REQUEST FOR AMENDMENT TO TECHNICAL SPECIFICATIONS

Attachment 1

REVISION B OF THE ITS SUBMITTAL

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SUMMARY DISPOSITION MATRIX FOR WNP-2

CURRENT TS NUMBER	TITLE	NEW TS NUMBER	RETAINED/ CRITERION FOR INCLUSION	BASIS FOR INCLUSION/EXCLUSION[(a)]
	REACTOR COOLANT SYSTEM (continued)			
3/4.4.1.2	Jet Pumps	3.4.3	Yes-3	Jet pump operability is assumed in the LOCA analysis to assure adequate core reflood capability.
3/4.4.1.3	Recirculation Loop Flow	3.4.1	Yes-2	Recirculation loop flow mismatch, within limits, is an initial condition in the safety analysis.
3/4.4.1.4	Idle Recirculation Loop Startup	3.4.12	Yes-2	Establishes initial conditions to operation such that operation is prohibited in areas or at temperature rate changes that might cause undetected flaws to propogate, in turn challenging the reactor coolant pressure boundary integrity.
3/4.4.2	Safety/Relief Valves	3.4.4 3.4.5	Yes-3	A minimum number of SRVs is assumed in the safety analyses to mitigate overpressure events.
3/4.4.3	Reactor Coolant System Leakage			
3/4.4.3.1	Leakage Detection System	3.4.8	Yes-1	Leak detection is used to indicate a significant abnormal condition of the reactor coolant system pressure boundary.
3/4.4.3.2	Operational Leakage	3.4.6 3.4.7	Yes-2	Leakage beyond limits would indicate an abnormal condition of the reactor coolant system pressure boundary. Operation in this condition is unanalyzed and may result in reactor coolant system pressure boundary failure.
3/4.4.4	Chemistry	Relocated	No	See Appendix A, Page 16.
3/4.4.5	Specific Activity	3.4.9	Yes-2	Specific activity provides an indication of the onset of significant fuel cladding failure and is an initial condition for evaluation of the consequences of an accident due to a main steam line break (MSLB) outside containment.
3/4.4.6	Pressure/Temperature Limits			
3/4.4.6.1	Reactor Coolant System	3.4.12	Yes-2	Establishes initial conditions to operation such that operation is prohibited in areas or at temperature rate changes that might cause undetected flaws to propagate in turn challenging the reactor coolant system pressure boundary integrity.

(a) The applicable safety analyses are discussed in the Bases for the individual Technical Specifications.

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

LCO Statement:

The isolation actuation instrumentation channels shown in Table 3.3.2-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.2-2. (13)

3/4.3.2.4.h RCIC Drywell Pressure - High

Discussion:

The function of the RCIC Drywell Pressure - High Function is to provide an isolation signal to the RCIC turbine exhaust inboard and outboard vacuum breaker isolation valves. A high drywell pressure signal in conjunction with a RCIC low steam line pressure signal will isolate the valves. The isolation of these portions of the RCIC system is not used to mitigate a design basis accident or transient. The two valves are not primary containment isolation valves. The isolation is provided for protection of the RCIC turbine exhaust lines against operation at high pressures which might cause damage to the equipment. Credit for this isolation is not assumed in any design basis analyses.

Comparison to Deterministic Screening Criteria:

1. The RCIC Drywell Pressure - High Function, in isolating the RCIC exhaust piping, is not used for, nor capable of, detecting a significant abnormal degradation of the reactor coolant pressure boundary prior to a design basis accident (DBA).

2. The RCIC Drywell Pressure - High Function is not a process variable that is an initial condition of a DBA or transient analysis.

3. The RCIC Drywell Pressure - High Function is not part of a primary success path in the mitigation of a DBA or transient. It is not assumed to function during a DBA or transient. In addition, the valves isolated by this function are not primary containment isolation valves.

4. As discussed in Sections 3.5 and 6, and summarized in Table 4.1 (Item 84) of NEDO-31466, the loss of the RCIC Drywell Pressure - High Function was found to be a non-significant risk contributor to core damage frequency and offsite releases. The Supply System has reviewed this evaluation, considers it applicable to WNP-2 and concurs with the assessment.

Conclusion:

Since the screening criteria have not been satisfied, the RCIC Drywell Pressure - High Function LCO and Surveillances may be relocated to other plant controlled documents outside the Technical Specifications.

3/4.3.3 ECCS ACTUATION INSTRUMENTATION

LCO Statement:

The emergency core cooling system (ECCS) actuation instrumentation channels shown in Table 3.3.3-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.3-2. (B)

3/4.3.3.A.2.g ADS 'A' - Manual Inhibit Switch.

3/4.3.3.B.2.f ADS 'B' - Manual Inhibit Switch.

Discussion:

The ADS Manual Inhibit Switch allows the operator to defeat ADS actuation as directed by the emergency operating procedures under conditions for which ADS would not be desirable. For example, during an ATWS event low pressure ECCS system activation would dilute sodium pentaborate injected by the Standby Liquid Control (SLC) System thereby reducing the effectiveness of the SLC System shutdown.

Comparison to Deterministic Screening Criteria:

1. The ADS Manual Inhibit Switch is not an instrument used for, nor capable of, detecting a significant abnormal degradation of the reactor coolant pressure boundary prior to a design basis accident (DBA).

2. The ADS Manual Inhibit Switch is not used for, nor capable of, monitoring a process variable that is an initial condition of a DBA or transient analyses.

3. The ADS Manual Inhibit Switch is not used as part of a primary success path in the mitigation of a DBA or transient. The inhibit feature was added to mitigate the consequences of an ATWS event, which is not a design basis accident or transient.

4. As discussed in Sections 3.5 and 6, and summarized in Table 4-1 (item 112B) of NEDO-31466, the loss of the ADS Manual Inhibit Switch was found to be a nonsignificant risk contributor to core damage frequency and offsite releases. The Supply System has reviewed this evaluation, considers it applicable to WNP-2 and concurs with the assessment.

Conclusion:

Since the screening criteria have not been satisfied, the portions of the LCO and Surveillances applicable to the ADS Manual Inhibit Switch may be relocated to other plant controlled documents outside the Technical Specifications.

1.1 Definitions (continued)

LEAKAGE	LEAKAGE shall be: a. Identified LEAKAGE 1. LEAKAGE into the drywell such as that from pump seals or valve packing, that is captured and conducted to a sump or collecting tank; or 2. LEAKAGE into the drywell atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary LEAKAGE; b. Unidentified LEAKAGE All LEAKAGE into the drywell that is not identified LEAKAGE; c. Total LEAKAGE Sum of the identified and unidentified LEAKAGE; and d. Pressure Boundary LEAKAGE LEAKAGE through a nonisolable fault in a Reactor Coolant System (RCS) component body, pipe wall, or vessel wall.
LINEAR HEAT GENERATION RATE (LHGR)	The LHGR shall be the heat generation rate per unit length of fuel rod. It is the integral of the heat flux over the heat transfer area associated with the unit length.
LOGIC SYSTEM FUNCTIONAL TEST	A LOGIC SYSTEM FUNCTIONAL TEST shall be a test of all required logic components (i.e., all required relays and contacts, trip units, solid state logic elements, etc.) of a logic circuit, from as close to the sensor as practicable up to, but not including, the actuated device, to verify OPERABILITY. The LOGIC SYSTEM FUNCTIONAL TEST may be performed by means of any series of sequential, overlapping, or total system steps so that the entire logic system is tested.

(continued)

1.1 Definitions (continued)

MAXIMUM FRACTION OF LIMITING POWER DENSITY (MFLPD)	The MFLPD shall be the largest value of the fraction of limiting power density (FLPD) in the core. The FLPD shall be the LHGR existing at a given location divided by the specified LHGR limit for that bundle type. (G)
MINIMUM CRITICAL POWER RATIO (MCPR)	The MCPR shall be the smallest critical power ratio (CPR) that exists in the core for each class of fuel. The CPR is that power in the assembly that is calculated by application of the appropriate correlation(s) to cause some point in the assembly to experience boiling transition, divided by the actual assembly operating power.
MODE	A MODE shall correspond to any one inclusive combination of mode switch position, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.
OPERABLE—OPERABILITY	A system, subsystem, division, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, division, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).
PHYSICS TESTS	PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are: a. Described in Chapter 14, Initial Test Program of the FSAR; b. Authorized under the provisions of 10 CFR 50.59; or c. Otherwise approved by the Nuclear Regulatory Commission.

(continued)

1.1 Definitions (continued)

PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)	The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.6.6. Plant operation within these operating limits is addressed in LCO 3.4.12, "RCS Pressure and Temperature (P/T) Limits."
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3486 MWt.
REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME	The RPS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its RPS trip setpoint at the channel sensor until de-energization of the scram pilot valve solenoids. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured.
SHUTDOWN MARGIN (SDM)	SDM shall be the amount of reactivity by which the reactor is subcritical or would be subcritical assuming that: a. The reactor is xenon free; b. The moderator temperature is 68°F; and c. All control rods are fully inserted except for the single control rod of highest reactivity worth, which is assumed to be fully withdrawn. With control rods not capable of being fully inserted, the reactivity worth of these control rods must be accounted for in the determination of SDM.
STAGGERED TEST BASIS	A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency, so that all systems, subsystems, channels, or other designated components are tested during *n* Surveillance Frequency intervals,

(continued)

1.1 Definitions

STAGGERED TEST BASIS (continued)	where *n* is the total number of systems, subsystems, channels, or other designated components in the associated function.
THERMAL POWER	THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.
TURBINE BYPASS SYSTEM RESPONSE TIME	The TURBINE BYPASS SYSTEM RESPONSE TIME shall be the time from when the turbine bypass control unit generates a turbine bypass valve flow signal until 80% of the turbine bypass capacity is established. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured.

2.0 SAFETY LIMITS (SLs)

2.1 SLs

2.1.1 Reactor Core SLs

2.1.1.1 With the reactor steam dome pressure < 785 psig or core flow < 10% rated core flow:

THERMAL POWER shall be ≤ 25% RTP.

2.1.1.2 With the reactor steam dome pressure ≥ 785 psig and core flow ≥ 10% rated core flow:

MCPR shall be ≥ 1.07 for two recirculation loop operation or ≥ 1.08 for single recirculation loop operation.

2.1.1.3 Reactor vessel water level shall be greater than the top of active irradiated fuel.

2.1.2 Reactor Coolant System Pressure SL

Reactor steam dome pressure shall be ≤ 1325 psig.

2.2 SL Violations

With any SL violation, the following actions shall be completed within 2 hours:

2.2.1 Restore compliance with all SLs; and

2.2.2 Insert all insertable control rods.

B

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.2.2 Declare the associated control rod inoperable.	1 hour
C. One or more control rod scram accumulators inoperable with reactor steam dome pressure < 900 psig.	C.1 Verify the associated control rod is fully inserted. AND C.2 Declare the associated control rod inoperable.	Immediately upon discovery of charging water header pressure < 940 psig 1 hour
D. Required Action B.1 or C.1 and associated Completion Time not met.	D.1 --------NOTE-------- Not applicable if all inoperable control rod scram accumulators are associated with fully inserted control rods. ---------- Place the reactor mode switch in the shutdown position.	 Immediately

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.6	----------NOTE---------- Only required to be met during entry into MODE 2 from MODE 1. ---------- Verify the IRM and APRM channels overlap.	7 days
SR 3.3.1.1.7	Calibrate the local power range monitors.	1130 MWD/T average core exposure (B)
SR 3.3.1.1.8	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.1.1.9	----------NOTES---------- 1. Neutron detectors are excluded. 2. For Function 2.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ---------- Perform CHANNEL CALIBRATION.	184 days
SR 3.3.1.1.10	----------NOTES---------- 1. Neutron detectors are excluded. 2. For Function 1, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ---------- Perform CHANNEL CALIBRATION.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.3.1.2	Perform CHANNEL CALIBRATION for Function 8.	92 days (B)
SR 3.3.3.1.3	Perform CHANNEL CALIBRATION for Functions 1, 2, 4, 5, 7, 9, and 10.	18 months
SR 3.3.3.1.4	Perform CHANNEL CALIBRATION for Functions 3 and 6.	24 months

SURVEILLANCE REQUIREMENTS

----------NOTE----------
When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours.

SURVEILLANCE		FREQUENCY
SR 3.3.3.2.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	31 days
SR 3.3.3.2.2	Perform CHANNEL CALIBRATION for each required instrumentation channel, except the suppression pool water level instrumentation channel.	18 months
SR 3.3.3.2.3	Perform CHANNEL CALIBRATION for the suppression pool water level instrumentation channel.	24 months (B)
SR 3.3.3.2.4	Verify each required control circuit and transfer switch is capable of performing the intended functions.	24 months

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.5.1-1 to determine which SRs apply for each ECCS Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed as follows: (a) for up to 6 hours for Functions 3.c, 3.f, and 3.g; and (b) for up to 6 hours for Functions other than 3.c, 3.f, and 3.g provided the associated Function or the redundant Function maintains ECCS initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.5.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.5.1.2	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.5.1.3	Perform CHANNEL CALIBRATION.	92 days
SR 3.3.5.1.4	Perform CHANNEL CALIBRATION.	18 months
SR 3.3.5.1.5	Perform CHANNEL CALIBRATION.	24 months (B)
SR 3.3.5.1.6	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months (B)

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

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	
1. Low Pressure Coolant Injection-A (LPCI) and Low Pressure Core Spray (LPCS) Subsystems						
a. Reactor Vessel Water Level – Low Low Low, Level 1	1,2,3, $4^{(a)},5^{(a)}$	$2^{(b)}$	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ -148 inches	(B)
b. Drywell Pressure – High	1,2,3	$2^{(b)}$	B	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≤ 1.88 psig	(B)
c. LPCS Pump Start – LOCA Time Delay Relay	1,2,3, $4^{(a)},5^{(a)}$	1	C	SR 3.3.5.1.5 SR 3.3.5.1.6	≥ 8.53 seconds and ≤ 10.64 seconds	(B)
d. LPCI Pump A Start – LOCA Time Delay Relay	1,2,3 $4^{(a)},5^{(a)}$	1	C	SR 3.3.5.1.5 SR 3.3.5.1.6	≥ 17.24 seconds and ≤ 21.53 seconds	(B)
e. LPCI Pump A Start – LOCA/LOOP Time Delay Relay	1,2,3, $4^{(a)},5^{(a)}$	1	C	SR 3.3.5.1.3 SR 3.3.5.1.6	≥ 3.04 seconds and ≤ 6.00 seconds	(B)
f. Reactor Vessel Pressure – Low (Injection Permissive)	1,2,3,	1 per valve	C	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ 448 psig and ≤ 492 psig	(A)
	$4^{(a)},5^{(a)}$	1 per valve	B	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ 448 psig and ≤ 492 psig	(A)
g. LPCS Pump Discharge Flow – Low (Minimum Flow)	1,2,3, $4^{(a)},5^{(a)}$	1	E	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ 668 gpm and ≤ 1067 gpm	(B)
h. LPCI Pump A Discharge Flow – Low (Minimum Flow)	1,2,3, $4^{(a)},5^{(a)}$	1	E	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ 605 gpm and ≤ 984 gpm	(B)
i. Manual Initiation	1,2,3, $4^{(a)},5^{(a)}$	2	C	SR 3.3.5.1.6	NA	(B)

(continued)

(a) When associated subsystem(s) are required to be OPERABLE.

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

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

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	
2. LPCI B and LPCI C Subsystems						
a. Reactor Vessel Water Level – Low Low Low, Level 1	1,2,3, $4^{(a)},5^{(a)}$	$2^{(b)}$	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ -148 inches	(B)
b. Drywell Pressure – High	1,2,3	$2^{(b)}$	B	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≤ 1.88 psig	(B)
c. LPCI Pump B Start – LOCA Time Delay Relay	1,2,3, $4^{(a)},5^{(a)}$	1	C	SR 3.3.5.1.5 SR 3.3.5.1.6	≥ 17.24 seconds and ≤ 21.53 seconds	
d. LPCI Pump C Start – LOCA Time Delay Relay	1,2,3 $4^{(a)},5^{(a)}$	1	C	SR 3.3.5.1.5 SR 3.3.5.1.6	≥ 8.53 seconds and ≤ 10.64 seconds	(B)
e. LPCI Pump B Start – LOCA/LOOP Time Delay Relay	1,2,3 $4^{(a)},5^{(a)}$	1	C	SR 3.3.5.1.3 SR 3.3.5.1.6	≥ 3.04 seconds and ≤ 6.00 seconds	(B)
f. Reactor Vessel Pressure – Low (Injection Permissive)	1,2,3,	1 per valve	C	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ 448 psig and ≤ 492 psig	(B)
	$4^{(a)},5^{(a)}$	1 per valve	B	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ 448 psig and ≤ 492 psig	(B)
g. LPCI Pumps B & C Discharge Flow – Low (Minimum Flow)	1,2,3 $4^{(a)},5^{(a)}$	1 per pump	E	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ 605 gpm and ≤ 984 gpm	(B)
h. Manual Initiation	1,2,3, $4^{(a)},5^{(a)}$	2	C	SR 3.3.5.1.6	NA	
3. High Pressure Core Spray (HPCS) System						
a. Reactor Vessel Water Level – Low Low, Level 2	1,2,3, $4^{(a)},5^{(a)}$	$4^{(b)}$	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ -58 inches	(B)

(continued)

(a) When associated subsystem(s) are required to be OPERABLE.

(b) Also required to initiate the associated DG.

Table 3.3.5.1-1 (page 3 of 4)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	
3. HPCS System (continued)						
b. Drywell Pressure – High	1,2,3	4[b]	B	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≤ 1.88 psig	(B)
c. Reactor Vessel Water Level – High, Level 8	1,2,3, 4[a],5[a]	2	C	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≤ 56.0 inches	(B)
d. Condensate Storage Tank Level – Low	1,2,3, 4[c],5[c]	2	D	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ 448 ft 1 inch elevation	(B)
e. Suppression Pool Water Level – High	1,2,3	2	D	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≤ 466 ft 11 inches elevation	(B)
f. HPCS System Flow Rate – Low (Minimum Flow)	1,2,3, 4[a],5[a]	1	E	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ 1200 gpm and ≤ 1512 gpm	(B)
g. Manual Initiation	1,2,3, 4[a],5[a]	2	C	SR 3.3.5.1.6	NA	
4. Automatic Depressurization System (ADS) Trip System A						
a. Reactor Vessel Water Level – Low Low Low, Level 1	1,2[d],3[d]	2	F	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ -148 inches	(B)
b. ADS Initiation Timer	1,2[d],3[d]	1	G	SR 3.3.5.1.3 SR 3.3.5.1.6	≤ 115.0 seconds	(B)
c. Reactor Vessel Water Level – Low, Level 3 (Permissive)	1,2[d],3[d]	1	F	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ 9.5 inches	(B)
d. LPCS Pump Discharge Pressure – High	1,2[d],3[d]	2	G	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ 119 psig and ≤ 171 psig	(B)

(continued)

(a) When associated subsystem(s) are required to be OPERABLE.

(b) Also required to initiate the associated DG.

(c) When HPCS is OPERABLE for compliance with LCO 3.5.2, "ECCS – Shutdown," and aligned to the condensate storage tank while tank water level is not within the limit of SR 3.5.2.2.

(d) With reactor steam dome pressure > 150 psig.

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

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	
4. ADS Trip System A (continued)						
e. LPCI Pump A Discharge Pressure – High	1,2[(d)],3[(d)]	2	G	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ 116 psig and ≤ 134 psig	(16)
f. Accumulator Backup Compressed Gas System Pressure – Low	1,2[(d)],3[(d)]	3	F	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ 154 psig	(16)
g. Manual Initiation	1,2[(d)],3[(d)]	4	G	SR 3.3.5.1.6	NA	
5. ADS Trip System B						
a. Reactor Vessel Water Level – Low Low Low, Level 1	1,2[(d)],3[(d)]	2	F	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ -148 inches	(13)
b. ADS Initiation Timer	1,2[(d)],3[(d)]	1	G	SR 3.3.5.1.3 SR 3.3.5.1.6	≤ 115.0 seconds	(14)
c. Reactor Vessel Water Level – Low, Level 3 (Permissive)	1,2[(d)],3[(d)]	1	F	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ 9.5 inches	(16)
d. LPCI Pumps B & C Discharge Pressure – High	1,2[(d)],3[(d)]	2 per pump	G	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ 116 psig and ≤ 134 psig	(16)
e. Accumulator Backup Compressed Gas System Pressure – Low	1,2[(d)],3[(d)]	3	F	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ 154 psig	(16)
f. Manual Initiation	1,2[(d)],3[(d)]	4	G	SR 3.3.5.1.6	NA	(16)

(d) With reactor steam dome pressure > 150 psig.

Table 3.3.6.1-1 (page 1 of 4)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Main Steam Line Isolation					
a. Reactor Vessel Water Level – Low Low, Level 2	1,2,3	2	D	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.6 SR 3.3.6.1.7	≥ -58 inches
b. Main Steam Line Pressure – Low	1	2	E	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.6 SR 3.3.6.1.7	≥ 804 psig
c. Main Steam Line Flow – High	1,2,3	2 per MSL	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.6 SR 3.3.6.1.7	≤ 124.4 psid
d. Condenser Vacuum – Low	1,2[(a)], 3[(a)]	2	D	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.6	≥ 7.2 inches Hg vacuum (B)
e. Main Steam Tunnel Temperature – High	1,2,3	2	D	SR 3.3.6.1.3 SR 3.3.6.1.4 SR 3.3.6.1.6	≤ 170°F
f. Main Steam Tunnel Differential Temperature – High	1,2,3	2	D	SR 3.3.6.1.3 SR 3.3.6.1.4 SR 3.3.6.1.6	≤ 90°F
g. Manual Initiation	1,2,3	4	G	SR 3.3.6.1.6	NA
2. Primary Containment Isolation					
a. Reactor Vessel Water Level – Low, Level 3	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.6	≥ 9.5 inches
b. Reactor Vessel Water Level – Low Low, Level 2	1,2,3	2	H	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.6	≥ -58 inches
c. Drywell Pressure – High	1,2,3	2	H	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.6	≤ 1.88 psig
d. Reactor Building Vent Exhaust Plenum Radiation – High	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.6	≤ 16.0 mR/hr
e. Manual Initiation	1,2,3	4	G	SR 3.3.6.1.6	NA

(continued)

(a) With any turbine throttle valve not closed.

Table 3.3.6.1-1 (page 4 of 4)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
5. RHR SDC System Isolation (continued)					
b. Pump Room Area Ventilation Differential Temperature – High	3	1 per room(d)	F	SR 3.3.6.1.3 SR 3.3.6.1.4 SR 3.3.6.1.6	≤ 70°F
c. Heat Exchanger Area Temperature – High	3	1 per room(d)	F	SR 3.3.6.1.3 SR 3.3.6.1.4 SR 3.3.6.1.6	
Room 505 Area					≤ 140°F
Room 507 Area					≤ 160°F
Room 605 Area					≤ 150°F
Room 606 Area					≤ 140°F
d. Reactor Vessel Water Level – Low, Level 3	3,4,5	2(d)(e)	J	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.6	≥ 9.5 inches
e. Reactor Vessel Pressure – High	1,2,3	1(d)	F	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.6	≤ 113 psig
f. Manual Initiation	1,2,3	2(d)	G	SR 3.3.6.1.6	NA

(d) Only the inboard trip system required in MODES 1, 2, and 3, as applicable, when the outboard valve control is transferred to the alternate remote shutdown panel and the outboard valve is closed.

(e) Only one trip system required in MODES 4 and 5 with RHR Shutdown Cooling System integrity maintained.

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.8.1-1 to determine which SRs apply for each LOP Function.

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

SURVEILLANCE		FREQUENCY
SR 3.3.8.1.1	Perform CHANNEL FUNCTIONAL TEST.	31 days
SR 3.3.8.1.2	Perform CHANNEL CALIBRATION.	18 months
SR 3.3.8.1.3	Perform CHANNEL CALIBRATION.	24 months (B)
SR 3.3.8.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months (B)

Table 3.3.8.1-1 (page 1 of 1)
Loss of Power Instrumentation

FUNCTION	REQUIRED CHANNELS PER DIVISION	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	
1. Divisions 1 and 2 - 4.16 kV Emergency Bus Undervoltage				
a. TR-S Loss of Voltage – 4.16 kV Basis	1	SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 2450 V and ≤ 3135 V	(A)
b. TR-S Loss of Voltage – Time Delay	1	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 2.65 seconds and ≤ 5.9 seconds	(A)
c. TR-B Loss of Voltage – 4.16 kV Basis	1	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 2450 V and ≤ 3135 V	(A)
d. TR-B Loss of Voltage – Time Delay	1	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 3.00 seconds and ≤ 6.00 seconds	(A)
e. Degraded Voltage – 4.16 kV Basis	2[a]	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 3685 V and ≤ 3755 V	(K)
f. Degraded Voltage – Primary Time Delay	2[a]	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 5.0 seconds and ≤ 5.3 seconds	(G)
g. Degraded Voltage – Secondary Time Delay	1	SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 2.63 seconds and ≤ 3.39 seconds	(B)
2. Division 3 - 4.16 kV Emergency Bus Undervoltage				
a. Loss of Voltage – 4.16 kV Basis	1[b]	SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 2450 V and ≤ 3135 V	(A)
b. Loss of Voltage – Time Delay	1[b]	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 1.2 seconds and ≤ 3.5 seconds	(A)
c. Degraded Voltage – 4.16 kV Basis	2	SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 3685 V and ≤ 3755 V	(A)
d. Degraded Voltage – Time Delay	2	SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 7.36 seconds and ≤ 8.34 seconds	(A)

(a) The Degraded Voltage – 4.16 kV Basis and – Primary Time Delay Functions must be associated with one another.

(b) The Loss of Voltage – 4.16 kV Basis and – Time Delay Functions must be in the same trip system.

3.3 INSTRUMENTATION

3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

LCO 3.3.8.2 Two RPS electric power monitoring assemblies shall be OPERABLE for each inservice RPS motor generator set or alternate power supply that supports equipment required to be OPERABLE. A

APPLICABILITY: MODES 1, 2, and 3,
MODES 4 and 5 with both residual heat removal (RHR) shutdown cooling (SDC) suction isolation valves open,
MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies. B

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or both required inservice power supplies with one electric power monitoring assembly inoperable.	A.1	Remove associated inservice power supply(s) from service.	72 hours A
B. One or both required inservice power supplies with both electric power monitoring assemblies inoperable.	B.1	Remove associated inservice power supply(s) from service.	1 hour B
C. Required Action and associated Completion Time of Condition A or B not met in MODE 1, 2, or 3.	C.1 AND	Be in MODE 3.	12 hours
	C.2	Be in MODE 4.	36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition A or B not met in MODE 4 or 5 with both RHR SDC suction isolation valves open.	D.1 Initiate action to restore one electric power monitoring assembly to OPERABLE status for inservice power supply(s) supplying required instrumentation. OR D.2 Initiate action to isolate the RHR SDC System.	Immediately Immediately
E. Required Action and associated Completion Time of Condition A or B not met in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.	E.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. Required Action and associated Completion Time of Condition F not met. OR No recirculation loops in operation in a Region other than Region A of the power-to-flow map.	G.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	----------NOTE---------- Not required to be performed until 24 hours after both recirculation loops are in operation. ----------	
	Verify recirculation loop drive flow mismatch with both recirculation loops in operation is:	24 hours (B)
	a. ≤ 10% of rated recirculation loop drive flow when operating at < 70% of rated core flow; and	(B)
	b. ≤ 5% of rated recirculation loop drive flow when operating at ≥ 70% of rated core flow.	(B)

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.1.2	Verify operation is in the "Unrestricted" Region of the power-to-flow map specified in the COLR.	24 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.2 Flow Control Valves (FCVs)

LCO 3.4.2 A recirculation loop FCV shall be OPERABLE in each operating recirculation loop.

APPLICABILITY: MODES 1 and 2.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each FCV.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or two required FCVs inoperable.	A.1 Lock up the FCV.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.2.1	Verify each FCV fails "as is" on loss of hydraulic pressure at the hydraulic unit.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.2.2	Verify average rate of each FCV movement is: a. ≤ 11% of stroke per second for opening; and b. ≤ 11% of stroke per second for closing.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.3 Jet Pumps

LCO 3.4.3 All jet pumps shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more jet pumps inoperable.	A.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.3.1	----------NOTES---------- 1. Not required to be performed until 4 hours after associated recirculation loop is in operation. 2. Not required to be performed until 24 hours after > 25% RTP. ---------- Verify at least two of the following criteria (a, b, and c) are satisfied for each operating recirculation loop: a. Recirculation loop drive flow versus flow control valve position differs by ≤ 10% from established patterns. b. Recirculation loop drive flow versus total core flow differs by ≤ 10% from established patterns. c. Each jet pump diffuser to lower plenum differential pressure differs by ≤ 20% from established patterns, or each jet pump flow differs by ≤ 10% from established patterns.	24 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.4 Safety/Relief Valves (SRVs) – ≥ 25% RTP

LCO 3.4.4 The safety function of 12 SRVs shall be OPERABLE, with two SRVs in the lowest two lift setpoint groups OPERABLE.

APPLICABILITY: THERMAL POWER ≥ 25% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required SRVs inoperable.	A.1 Reduce THERMAL POWER to < 25% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.4.1	Verify the safety function lift setpoints of the required SRVs are as follows: Number of SRVs / Setpoint (psig) 2 / 1165 ± 34.9 4 / 1175 ± 35.2 4 / 1185 ± 35.5 4 / 1195 ± 35.8 4 / 1205 ± 36.1	In accordance with the Inservice Testing Program
SR 3.4.4.2	Verify each required SRV opens when manually actuated.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.5 Safety/Relief Valves (SRVs) – < 25% RTP

LCO 3.4.5 The safety function of four SRVs shall be OPERABLE.

APPLICABILITY: MODE 1 with THERMAL POWER < 25% RTP,
MODES 2 and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required SRVs inoperable.	A.1 Be in MODE 3. AND A.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.1	Verify the safety function lift setpoints of the required SRVs are as follows: Number of SRVs: 2 — Setpoint (psig): 1165 ± 34.9 Number of SRVs: 4 — Setpoint (psig): 1175 ± 35.2 Number of SRVs: 4 — Setpoint (psig): 1185 ± 35.5 Number of SRVs: 4 — Setpoint (psig): 1195 ± 35.8 Number of SRVs: 4 — Setpoint (psig): 1205 ± 36.1	In accordance with the Inservice Testing Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.4.5.2	----------NOTE---------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. ---------- Verify each required SRV opens when manually actuated.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.6 RCS Operational LEAKAGE

LCO 3.4.6 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE;

b. ≤ 5 gpm unidentified LEAKAGE;

c. ≤ 25 gpm total LEAKAGE averaged over the previous 24 hour period; and

d. ≤ 2 gpm increase in unidentified LEAKAGE within the previous 24 hour period in MODE 1.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Unidentified LEAKAGE not within limit. OR Total LEAKAGE not within limit.	A.1 Reduce LEAKAGE to within limits.	4 hours
B. Unidentified LEAKAGE increase not within limit.	B.1 Reduce unidentified LEAKAGE increase to within limit. OR	4 hours (continued)

ACTIONS.

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

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	Verify RCS unidentified and total LEAKAGE and unidentified LEAKAGE increase are within limits.	12 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.7 RCS Pressure Isolation Valve (PIV) Leakage

LCO 3.4.7 The leakage from each RCS PIV shall be within limit.

APPLICABILITY: MODES 1 and 2,
MODE 3, except valves in the residual heat removal shutdown cooling flowpath when in, or during transition to or from, the shutdown cooling mode of operation.

ACTIONS

----------NOTES----------
1. Separate Condition entry is allowed for each flow path.

2. Enter applicable Conditions and Required Actions for systems made inoperable by PIVs.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more flow paths with leakage from one or more RCS PIVs not within limit.	----------NOTE---------- Each check valve used to satisfy Required Action A.1 shall have been verified to meet SR 3.4.7.1 and be in the reactor coolant pressure boundary. ---------- A.1 Isolate the high pressure portion of the affected system from the low pressure portion by use of one closed manual, de-activated automatic, or check valve.	4 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.7.1	----------NOTE---------- Only required to be performed in MODES 1 and 2. ---------- Verify equivalent leakage of each RCS PIV is ≤ 0.5 gpm per nominal inch of valve size up to a maximum of 5 gpm, at an RCS pressure of 1035 psig. The actual test pressure shall be ≥ 935 psig.	In accordance with Inservice Testing Program (B)

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.8 RCS Leakage Detection Instrumentation

LCO 3.4.8 The following RCS leakage detection instrumentation shall be OPERABLE:

a. Drywell floor drain sump flow monitoring system; and

b. One channel of either drywell atmospheric particulate or atmospheric gaseous monitoring system.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Drywell floor drain sump flow monitoring system inoperable.	----------NOTE---------- LCO 3.0.4 is not applicable. ---------- A.1 Restore drywell floor drain sump flow monitoring system to OPERABLE status.	30 days
B. Required drywell atmospheric monitoring system inoperable.	----------NOTE---------- LCO 3.0.4 is not applicable. ---------- B.1 Analyze grab samples of drywell atmosphere. AND B.2 Restore required drywell atmospheric monitoring system to OPERABLE status.	Once per 12 hours 30 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours
D. All required leakage detection systems inoperable.	D.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

----------NOTE----------
When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the other required leakage detection instrumentation is OPERABLE.

SURVEILLANCE		FREQUENCY
SR 3.4.8.1	Perform CHANNEL CHECK of required drywell atmospheric monitoring system.	12 hours
SR 3.4.8.2	Perform CHANNEL FUNCTIONAL TEST of required leakage detection instrumentation.	31 days
SR 3.4.8.3	Perform CHANNEL CALIBRATION of required leakage detection instrumentation.	18 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.9 RCS Specific Activity

LCO 3.4.9 The specific activity of the reactor coolant shall be limited to DOSE EQUIVALENT I-131 specific activity ≤ 0.2 μCi/gm.

APPLICABILITY: MODE 1,
MODES 2 and 3 with any main steam line not isolated.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Reactor coolant specific activity > 0.2 μCi/gm and ≤ 4.0 μCi/gm DOSE EQUIVALENT I-131.	----------NOTE---------- LCO 3.0.4 is not applicable. ---------- A.1 Determine DOSE EQUIVALENT I-131. AND A.2 Restore DOSE EQUIVALENT I-131 to within limits.	 Once per 4 hours 48 hours
B. Required Action and associated Completion Time of Condition A not met. OR Reactor coolant specific activity > 4.0 μCi/gm DOSE EQUIVALENT I-131.	B.1 Determine DOSE EQUIVALENT I-131. AND B.2.1 Isolate all main steam lines. OR	Once per 4 hours 12 hours

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.2.2.1 Be in MODE 3. AND B.2.2.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.9.1	----------NOTE---------- Only required to be performed in MODE 1. ---------- Verify reactor coolant DOSE EQUIVALENT I-131 specific activity is ≤ 0.2 μCi/gm.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.10 Residual Heat Removal (RHR) Shutdown Cooling System – Hot Shutdown

LCO 3.4.10 Two RHR shutdown cooling subsystems shall be OPERABLE, and, with no recirculation pump in operation, at least one RHR shutdown cooling subsystem shall be in operation.

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

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

2. One RHR shutdown cooling subsystem may be inoperable for up to 2 hours for performance of Surveillances.

APPLICABILITY: MODE 3 with reactor steam dome pressure less than the RHR cut-in permissive pressure.

ACTIONS

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

1. LCO 3.0.4 is not applicable.

2. Separate Condition entry is allowed for each RHR shutdown cooling subsystem.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2	Verify an alternate method of decay heat removal is available for each inoperable RHR shutdown cooling subsystem.	1 hour
	AND		
	A.3	Be in MODE 4.	24 hours
B. No RHR shutdown cooling subsystem in operation. AND No recirculation pump in operation.	B.1	Initiate action to restore one RHR shutdown cooling subsystem or one recirculation pump to operation.	Immediately
	AND		
	B.2	Verify reactor coolant circulation by an alternate method.	1 hour from discovery of no reactor coolant circulation AND Once per 12 hours thereafter
	AND		
	B.3	Monitor reactor coolant temperature and pressure.	Once per hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.10.1	----------NOTE---------- Not required to be met until 2 hours after reactor steam dome pressure is less than the RHR cut-in permissive pressure. ---------- Verify one RHR shutdown cooling subsystem or recirculation pump is operating.	12 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.11 Residual Heat Removal (RHR) Shutdown Cooling System – Cold Shutdown

LCO 3.4.11 Two RHR shutdown cooling subsystems shall be OPERABLE, and, with no recirculation pump in operation, at least one RHR shutdown cooling subsystem shall be in operation.

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

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

2. One RHR shutdown cooling subsystem may be inoperable for up to 2 hours for the performance of Surveillances.

APPLICABILITY: MODE 4.

ACTIONS

----------NOTE----------

Separate Condition entry is allowed for each RHR shutdown cooling subsystem.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or two RHR shutdown cooling subsystems inoperable.	A.1 Verify an alternate method of decay heat removal is available for each inoperable RHR shutdown cooling subsystem.	1 hour AND Once per 24 hours thereafter

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. No RHR shutdown cooling subsystem in operation. AND No recirculation pump in operation.	B.1 Verify reactor coolant circulating by an alternate method. AND B.2 Monitor reactor coolant temperature and pressure.	1 hour from discovery of no reactor coolant circulation AND Once per 12 hours thereafter Once per hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.11.1	Verify one RHR shutdown cooling subsystem or recirculation pump is operating.	12 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.12 RCS Pressure and Temperature (P/T) Limits

LCO 3.4.12 RCS pressure, RCS temperature, RCS heatup and cooldown rates, and the recirculation loop temperature requirements shall be maintained within the limits specified in the PTLR.

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. ---------NOTE--------- Required Action A.2 shall be completed if this Condition is entered. ---------- Requirements of the LCO not met in MODE 1, 2, or 3.	A.1	Restore parameter(s) to within limits.	30 minutes
	AND		
	A.2	Determine RCS is acceptable for continued operation.	72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 3.	12 hours
	AND		
	B.2	Be in MODE 4.	36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. ---------NOTE--------- Required Action C.2 shall be completed if this Condition is entered. ---------- Requirements of the LCO not met in other than MODES 1, 2, and 3.	C.1 Initiate action to restore parameter(s) to within limits. AND C.2 Determine RCS is acceptable for operation.	Immediately Prior to entering MODE 2 or 3

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.12.1	----------NOTE---------- Only required to be performed during RCS heatup and cooldown operations, and RCS inservice leak and hydrostatic testing. ---------- Verify RCS pressure, RCS temperature, and RCS heatup and cooldown rates are within the limits specified in the PTLR.	30 minutes
SR 3.4.12.2	Verify RCS pressure and RCS temperature are within the criticality limits specified in the PTLR.	Once within 15 minutes prior to control rod withdrawal for the purpose of achieving criticality

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.12.3	----------NOTE---------- Only required to be met in MODES 1, 2, 3, and 4 during recirculation pump startup. ---------- Verify the difference between the bottom head coolant temperature and the reactor pressure vessel (RPV) coolant temperature is within the limits specified in the PTLR.	Once within 15 minutes prior to each startup of a recirculation pump
SR 3.4.12.4	----------NOTE---------- Only required to be met in MODES 1, 2, 3, and 4 during recirculation pump startup. ---------- Verify the difference between the reactor coolant temperature in the recirculation loop to be started and the RPV coolant temperature is within the limits specified in the PTLR.	Once within 15 minutes prior to each startup of a recirculation pump
SR 3.4.12.5	----------NOTE---------- Only required to be met in single loop operation with THERMAL POWER ≤ 25% RTP or the operating recirculation loop flow ≤ 10% rated loop flow. ---------- Verify the difference between the bottom head coolant temperature and the RPV coolant temperature is within the limits specified in the PTLR.	Once within 15 minutes prior to an increase in THERMAL POWER or an increase in loop flow

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.4.12.6	----------NOTE---------- Only required to be met in single loop operation when the idle recirculation loop is not isolated from the RPV, and with THERMAL POWER ≤ 25% RTP or the operating recirculation loop flow ≤ 10% rated loop flow. ---------- Verify the difference between the reactor coolant temperature in the recirculation loop not in operation and the RPV coolant temperature is within the limits specified in the PTLR.	Once within 15 minutes prior to an increase in THERMAL POWER or an increase in loop flow
SR 3.4.12.7	----------NOTE---------- Only required to be performed when tensioning the reactor vessel head bolting studs. ---------- Verify reactor vessel flange and head flange temperatures are within the limits specified in the PTLR.	30 minutes
SR 3.4.12.8	----------NOTE---------- Not required to be performed until 30 minutes after RCS temperature ≤ 90°F in MODE 4. ---------- Verify reactor vessel flange and head flange temperatures are within the limits specified in the PTLR.	30 minutes

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.12.9	----------NOTE---------- Not required to be performed until 12 hours after RCS temperature ≤ 100°F in MODE 4. ---------- Verify reactor vessel flange and head flange temperatures are within the limits specified in the PTLR.	12 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.13 Reactor Steam Dome Pressure

LCO 3.4.13 The reactor steam dome pressure shall be ≤ 1035 psig.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Reactor steam dome pressure not within limit.	A.1 Restore reactor steam dome pressure to within limit.	15 minutes
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.13.1 Verify reactor steam dome pressure is ≤ 1035 psig.	12 hours

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

3.5.1 ECCS – Operating

LCO 3.5.1 Each ECCS injection/spray subsystem and the Automatic Depressurization System (ADS) function of six safety/relief valves shall be OPERABLE. |(B)

APPLICABILITY: MODE 1,
MODES 2 and 3, except ADS valves are not required to be OPERABLE with reactor steam dome pressure ≤ 150 psig.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One low pressure ECCS injection/spray subsystem inoperable.	A.1 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	14 days
B. High Pressure Core Spray (HPCS) System inoperable.	B.1 Verify by administrative means RCIC System is OPERABLE when RCIC System is required to be OPERABLE. AND B.2 Restore HPCS System to OPERABLE status.	Immediately 14 days

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.1.1	Perform required visual examinations and leakage rate testing except for primary containment air lock testing, in accordance with the Primary Containment Leakage Rate Testing Program.	In accordance with the Primary Containment Leakage Rate Testing Program
SR 3.6.1.1.2	Verify drywell to suppression chamber bypass leakage rate is less than or equal to the equivalent leakage rate through an orifice 0.005 ft^2 at an initial differential pressure of $\geq$ 1.5 psid.	24 months AND -----NOTE------ Only required after two consecutive tests fail and continues until two consecutive tests pass ---------- 12 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.2.1	----------NOTES---------- 1. An inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. 2. Results shall be evaluated against acceptance criteria applicable to SR 3.6.1.1.1. ---------- Perform required primary containment air lock leakage rate testing in accordance with the Primary Containment Leakage Rate Testing Program.	In accordance with the Primary Containment Leakage Rate Testing Program (B) (B)
SR 3.6.1.2.2	Verify only one door in the primary containment air lock can be opened at a time.	24 months

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.7	Verify each automatic PCIV actuates to the isolation position on an actual or simulated isolation signal.	24 months
SR 3.6.1.3.8	Verify each EFCV actuates to the isolation position on an actual or simulated instrument line break signal.	24 months
SR 3.6.1.3.9	Remove and test the explosive squib from each shear isolation valve of the TIP System.	24 months on a STAGGERED TEST BASIS
SR 3.6.1.3.10	Verify the combined leakage rate for all secondary containment bypass leakage paths is $\leq$ 0.74 scfh when pressurized to $\geq P_a$.	In accordance with the Primary Containment Leakage Rate Testing Program
SR 3.6.1.3.11	Verify leakage rate through each MSIV is $\leq$ 11.5 scfh when tested at $\geq$ 25.0 psig.	In accordance with the Primary Containment Leakage Rate Testing Program
SR 3.6.1.3.12	Verify combined leakage rate through hydrostatically tested lines that penetrate the primary containment is within limits.	In accordance with the Primary Containment Leakage Rate Testing Program

3.6 CONTAINMENT SYSTEMS

3.6.1.4 Drywell Air Temperature

LCO 3.6.1.4 Drywell average air temperature shall be ≤ 135°F.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Drywell average air temperature not within limit.	A.1 Restore drywell average air temperature to within limit.	8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.4.1	Verify drywell average air temperature is within limit.	24 hours

3.6 CONTAINMENT SYSTEMS

3.6.1.5 Residual Heat Removal (RHR) Drywell Spray

LCO 3.6.1.5 Two RHR drywell spray subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR drywell spray subsystem inoperable.	A.1 Restore RHR drywell spray subsystem to OPERABLE status.	7 days
B. Two RHR drywell spray subsystems inoperable.	B.1 Restore one RHR drywell spray subsystem to OPERABLE status.	8 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.5.1	Verify each RHR drywell spray subsystem manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, is in the correct position or can be aligned to the correct position.	31 days
SR 3.6.1.5.2	Verify each spray nozzle is unobstructed.	10 years

3.6 CONTAINMENT SYSTEMS

3.6.1.6 Reactor Building-to-Suppression Chamber Vacuum Breakers

LCO 3.6.1.6 Each reactor building-to-suppression chamber vacuum breaker shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each line.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more lines with one reactor building-to-suppression chamber vacuum breaker not closed.	A.1 Close the open vacuum breaker.	72 hours
B. One or more lines with two reactor building-to-suppression chamber vacuum breakers not closed.	B.1 Close one open vacuum breaker.	1 hour
C. One line with one or more reactor building-to-suppression chamber vacuum breakers inoperable for opening.	C.1 Restore the vacuum breaker(s) to OPERABLE status.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Two or more lines with one or more reactor building-to-suppression chamber vacuum breakers inoperable for opening.	D.1 Restore all vacuum breakers in two lines to OPERABLE status.	1 hour
E. Required Action and associated Completion Time not met.	E.1 Be in MODE 3. AND E.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.6.1	----------NOTES---------- 1. Not required to be met for vacuum breakers that are open during Surveillances. 2. Not required to be met for vacuum breakers open when performing their intended function. ---------- Verify each vacuum breaker is closed.	14 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.6.2	Perform a functional test of each vacuum breaker.	In accordance with the Inservice Testing Program
SR 3.6.1.6.3	Verify the full open setpoint of each vacuum breaker is ≤ 0.5 psid.	24 months

3.6 CONTAINMENT SYSTEMS

3.6.1.7 Suppression Chamber-to-Drywell Vacuum Breakers

LCO 3.6.1.7 Seven suppression chamber-to-drywell vacuum breakers shall be OPERABLE for opening.

AND

Nine suppression chamber-to-drywell vacuum breakers shall be closed, except when performing their intended function.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required suppression chamber-to-drywell vacuum breaker inoperable for opening.	A.1 Restore one vacuum breaker to OPERABLE status.	72 hours
B. ---------NOTE--------- Separate Condition entry is allowed for each suppression chamber-to-drywell vacuum breaker. ---------- One or more suppression chamber-to-drywell vacuum breakers with one disk not closed.	B.1 Close the open vacuum breaker disk.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. ---------NOTE--------- Separate Condition entry is allowed for each suppression chamber-to-drywell vacuum breaker. ---------- One or more suppression chamber-to-drywell vacuum breakers with two disks not closed.	C.1 Close one open vacuum breaker disk.	2 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.7.1	----------NOTE---------- Not required to be met for vacuum breakers that are open during Surveillances. ---------- Verify each vacuum breaker is closed.	14 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.7.2	Perform a functional test of each required vacuum breaker.	31 days AND Within 12 hours after any discharge of steam to the suppression chamber from the safety/ relief valves
SR 3.6.1.7.3	Verify the full open setpoint of each required vacuum breaker is ≤ 0.5 psid.	24 months

3.6 CONTAINMENT SYSTEMS

3.6.1.8 Main Steam Isolation Valve Leakage Control (MSLC) System

LCO 3.6.1.8 Two MSLC subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One MSLC subsystem inoperable.	A.1 Restore MSLC subsystem to OPERABLE status.	30 days
B. Two MSLC subsystems inoperable.	B.1 Restore one MSLC subsystem to OPERABLE status.	7 days
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.6.1.8.1 Operate each MSLC blower ≥ 15 minutes.	31 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.8.2	Verify electrical continuity of each inboard MSLC subsystem heater element circuitry.	31 days
SR 3.6.1.8.3	Perform a system functional test of each MSLC subsystem.	18 months

3.6 CONTAINMENT SYSTEMS

3.6.2.1 Suppression Pool Average Temperature

LCO 3.6.2.1 Suppression pool average temperature shall be:

a. ≤ 90°F when THERMAL POWER is > 1% RTP and no testing that adds heat to the suppression pool is being performed;

b. ≤ 105°F when THERMAL POWER is > 1% RTP and testing that adds heat to the suppression pool is being performed; and

c. ≤ 110°F when THERMAL POWER is ≤ 1% RTP.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Suppression pool average temperature > 90°F but ≤ 110°F. AND THERMAL POWER > 1% RTP. AND Not performing testing that adds heat to the suppression pool.	A.1 Verify suppression pool average temperature ≤ 110°F. AND A.2 Restore suppression pool average temperature to ≤ 90°F.	Once per hour 24 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Reduce THERMAL POWER to ≤ 1% RTP.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Suppression pool average temperature > 105°F. AND THERMAL POWER > 1% RTP. AND Performing testing that adds heat to the suppression pool.	C.1 Suspend all testing that adds heat to the suppression pool.	Immediately
D. Suppression pool average temperature > 110°F but ≤ 120°F.	D.1 Place the reactor mode switch in the shutdown position. AND D.2 Verify suppression pool average temperature ≤ 120°F. AND D.3 Be in MODE 4.	Immediately Once per 30 minutes 36 hours
E. Suppression pool average temperature > 120°F.	E.1 Depressurize the reactor vessel to < 200 psig. AND E.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.1.1	Verify suppression pool average temperature is within the applicable limits.	24 hours AND 5 minutes when performing testing that adds heat to the suppression pool

3.6 CONTAINMENT SYSTEMS

3.6.2.2 Suppression Pool Water Level

LCO 3.6.2.2 Suppression pool water level shall be ≥ 30 ft 9.75 inches and ≤ 31 ft 1.75 inches. 1 (B)

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Suppression pool water level not within limits.	A.1 Restore suppression pool water level to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.2.1	Verify suppression pool water level is within limits.	24 hours

3.6 CONTAINMENT SYSTEMS

3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

LCO 3.6.2.3 Two RHR suppression pool cooling subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR suppression pool cooling subsystem inoperable.	A.1 Restore RHR suppression pool cooling subsystem to OPERABLE status.	7 days
B. Two RHR suppression pool cooling subsystems inoperable.	B.1 Restore one RHR suppression pool cooling subsystem to OPERABLE status.	8 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.3.1	Verify each RHR suppression pool cooling subsystem manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, is in the correct position or can be aligned to the correct position.	31 days
SR 3.6.2.3.2	Verify each RHR pump develops a flow rate ≥ 7100 gpm through the associated heat exchanger while operating in the suppression pool cooling mode.	In accordance with the Inservice Testing Program

3.6 CONTAINMENT SYSTEMS

3.6.3.1 Primary Containment Hydrogen Recombiners

LCO 3.6.3.1 Two primary containment hydrogen recombiners shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One primary containment hydrogen recombiner inoperable.	A.1 --------NOTE-------- LCO 3.0.4 is not applicable. ---------- Restore primary containment hydrogen recombiner to OPERABLE status.	30 days
B. Two primary containment hydrogen recombiners inoperable.	B.1 Verify by administrative means that the hydrogen and oxygen control function is maintained. AND B.2 Restore one primary containment hydrogen recombiner to OPERABLE status.	1 hour AND One per 12 hours thereafter 7 days
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.1.1	Perform a system functional test for each primary containment hydrogen recombiner.	24 months
SR 3.6.3.1.2	Visually examine each primary containment hydrogen recombiner enclosure and verify there is no evidence of abnormal conditions.	24 months
SR 3.6.3.1.3	Perform a resistance to ground test for each heater phase.	24 months

3.6 CONTAINMENT SYSTEMS

3.6.3.2 Primary Containment Atmosphere Mixing System

LCO 3.6.3.2 Two head area return fans shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One head area return fan inoperable.	----------NOTE---------- LCO 3.0.4 is not applicable. ---------- A.1 Restore head area return fan to OPERABLE status.	30 days
B. Two head area return fans inoperable.	B.1 Verify by administrative means that the hydrogen and oxygen control function is maintained. AND B.2 Restore one head area return fan to OPERABLE status.	1 hour 7 days
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.2.1	Operate each head area return fan for ≥ 15 minutes.	92 days

3.6 CONTAINMENT SYSTEMS

3.6.3.3 Primary Containment Oxygen Concentration

LCO 3.6.3.3 The primary containment oxygen concentration shall be < 3.5 volume percent.

APPLICABILITY: MODE 1 during the time period:

a. From 24 hours after THERMAL POWER is > 15% RTP following startup, to

b. 24 hours prior to reducing THERMAL POWER to < 15% RTP prior to the next scheduled reactor shutdown.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Primary containment oxygen concentration not within limit.	A.1 Restore oxygen concentration to within limit.	24 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to ≤ 15% RTP.	8 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.3.1	Verify primary containment oxygen concentration is within limits.	7 days

3.6 CONTAINMENT SYSTEMS

3.6.4.1 Secondary Containment

LCO 3.6.4.1 The secondary containment shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
During movement of irradiated fuel assemblies in the secondary containment,
During CORE ALTERATIONS,
During operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Secondary containment inoperable in MODE 1, 2, or 3.	A.1 Restore secondary containment to OPERABLE status.	4 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Secondary containment inoperable during movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs.	C.1 --------NOTE-------- LCO 3.0.3 is not applicable. ---------- Suspend movement of irradiated fuel assemblies in the secondary containment.	Immediately
	AND	
	C.2 Suspend CORE ALTERATIONS.	Immediately
	AND	
	C.3 Initiate action to suspend OPDRVs.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.1.1	Verify secondary containment vacuum is ≥ 0.25 inch of vacuum water gauge.	24 hours
SR 3.6.4.1.2	Verify all secondary containment equipment hatches are closed and sealed.	31 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.4.1.3	Verify each secondary containment access inner door or each secondary containment access outer door in each access opening is closed.	31 days
SR 3.6.4.1.4	Verify each standby gas treatment (SGT) subsystem will draw down the secondary containment to ≥ 0.25 inch of vacuum water gauge in ≤ 120 seconds.	24 months on a STAGGERED TEST BASIS
SR 3.6.4.1.5	Verify each SGT subsystem can maintain ≥ 0.25 inch of vacuum water gauge in the secondary containment for 1 hour at a flow rate ≤ 2240 cfm.	24 months on a STAGGERED TEST BASIS

3.6 CONTAINMENT SYSTEMS

3.6.4.2 Secondary Containment Isolation Valves (SCIVs)

LCO 3.6.4.2 Each SCIV shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
During movement of irradiated fuel assemblies in the secondary containment,
During CORE ALTERATIONS,
During operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

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

1. Penetration flow paths may be unisolated intermittently under administrative controls.
2. Separate Condition entry is allowed for each penetration flow path.
3. Enter applicable Conditions and Required Actions for systems made inoperable by SCIVs.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more penetration flow paths with one SCIV inoperable.	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange. AND	8 hours (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 --------NOTE-------- Isolation devices in high radiation areas may be verified by use of administrative means. ---------- Verify the affected penetration flow path is isolated.	Once per 31 days
B. --------NOTE-------- Only applicable to penetration flow paths with two isolation valves. ---------- One or more penetration flow paths with two SCIVs inoperable.	B.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	4 hours
C. Required Action and associated Completion Time of Condition A or B not met in MODE 1, 2, or 3.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. Required Action and associated Completion Time of Condition A or B not met during movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs.	D.1	--------NOTE-------- LCO 3.0.3 is not applicable. ---------- Suspend movement of irradiated fuel assemblies in the secondary containment.	Immediately
	AND		
	D.2	Suspend CORE ALTERATIONS.	Immediately
	AND		
	D.3	Initiate action to suspend OPDRVs.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.2.1	----------NOTES---------- 1. Valves and blind flanges in high radiation areas may be verified by use of administrative controls. 2. Not required to be met for SCIVs that are open under administrative controls. ---------- Verify each secondary containment isolation manual valve and blind flange that is required to be closed during accident conditions is closed.	31 days
SR 3.6.4.2.2	Verify the isolation time of each power operated and each automatic SCIV is within limits.	In accordance with the Inservice Testing Program
SR 3.6.4.2.3	Verify each automatic SCIV actuates to the isolation position on an actual or simulated automatic isolation signal.	24 months

3.6 CONTAINMENT SYSTEMS

3.6.4.3 Standby Gas Treatment (SGT) System

LCO 3.6.4.3 Two SGT subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
During movement of irradiated fuel assemblies in the secondary containment,
During CORE ALTERATIONS,
During operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One SGT subsystem inoperable.	A.1 Restore SGT subsystem to OPERABLE status.	7 days
B. Required Action and associated Completion Time of Condition A not met in MODE 1, 2, or 3.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours
C. Required Action and associated Completion Time of Condition A not met during movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs.	----------NOTE---------- LCO 3.0.3 is not applicable. ---------- C.1 Place OPERABLE SGT subsystem in operation. OR	Immediately

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2.1 Suspend movement of irradiated fuel assemblies in the secondary containment. AND C.2.2 Suspend CORE ALTERATIONS. AND C.2.3 Initiate action to suspend OPDRVs.	Immediately Immediately Immediately
D. Two SGT subsystems inoperable in MODE 1, 2, or 3.	D.1 Enter LCO 3.0.3.	Immediately
E. Two SGT subsystems inoperable during movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs.	E.1 --------NOTE-------- LCO 3.0.3 is not applicable. ---------- Suspend movement of irradiated fuel assemblies in the secondary containment. AND E.2 Suspend CORE ALTERATIONS. AND E.3 Initiate action to suspend OPDRVs.	 Immediately Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.3.1	Operate each SGT subsystem for ≥ 10 continuous hours with heaters operating.	31 days
SR 3.6.4.3.2	Perform required SGT filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP
SR 3.6.4.3.3	Verify each SGT subsystem actuates on an actual or simulated initiation signal.	24 months
SR 3.6.4.3.4	Verify each SGT filter cooling recirculation valve can be opened and the fan started.	24 months

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.15	----------NOTES---------- 1. This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ 1 hour loaded ≥ 4000 kW for DG-1 and DG-2, and ≥ 2340 kW for DG-3. Momentary transients outside of load range do not invalidate this test. 2. All DG starts may be preceded by an engine prelube period. ---------- Verify each required DG starts and achieves: a. For DG-1 and DG-2, in ≤ 15 seconds, voltage ≥ 3910 V and frequency ≥ 58.8 Hz, and after steady state conditions are reached, maintains voltage ≥ 3910 V and ≤ 4400 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz; and b. For DG-3, in ≤ 15 seconds, voltage ≥ 3740 V and frequency ≥ 58.8 Hz, and after steady state conditions are reached, maintains voltage ≥ 3740 V and ≤ 4400 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	24 months

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.2 AC Sources – Shutdown

LCO 3.8.2 The following AC electrical power sources shall be OPERABLE:

a. One qualified circuit between the offsite transmission network and the onsite Class 1E AC electrical power distribution subsystem(s) required by LCO 3.8.8, "Distribution Systems – Shutdown"; (B)

b. One diesel generator (DG) capable of supplying one division of the Division 1 or 2 onsite Class 1E AC electrical power distribution subsystem(s) required by LCO 3.8.8; and

c. The Division 3 DG capable of supplying the Division 3 onsite Class 1E AC electrical power distribution subsystem, when the Division 3 onsite Class 1E electrical power distribution subsystem is required by LCO 3.8.8.

APPLICABILITY: MODES 4 and 5,
During movement of irradiated fuel assemblies in the secondary containment.

3.8 ELECTRICAL POWER SYSTEMS

3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

LCO 3.8.3 The stored diesel fuel oil, lube oil, and starting air subsystem shall be within limits for each required diesel generator (DG).

APPLICABILITY: When associated DG is required to be OPERABLE.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each DG.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more DGs with stored fuel oil level: 1. For DG-1 or DG-2, < 55,500 gal and ≥ 47,520 gal; and 2. For DG-3, < 33,000 gal and ≥ 28,340 gal.	A.1 Restore stored fuel oil level to within limit.	48 hours
B. One or more DGs with lube oil inventory: 1. For DG-1 or DG-2, < 330 gal and ≥ 283 gal; and 2. For DG-3, < 165 gal and ≥ 142 gal.	B.1 Restore lube oil inventory to within limit.	48 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more DGs with stored fuel oil total particulates not within limit.	C.1 Restore stored fuel oil total particulates to within limit.	7 days
D. One or more DGs with new fuel oil properties not within limits.	D.1 Restore stored fuel oil properties to within limits.	30 days
E. One or more DGs with required starting air receiver pressure: 1. For DG-1 and DG-2, < 230 psig and ≥ 150 psig; and 2. For DG-3, < 223 psig and ≥ 150 psig.	E.1 Restore required starting air receiver pressure to within limit.	48 hours
F. Required Action and associated Completion Time of Condition A, B, C, D, or E not met. OR One or more DGs with stored diesel fuel oil, lube oil, or starting air subsystem not within limits for reasons other than Condition A, B, C, D, or E.	F.1 Declare associated DG inoperable.	Immediately

(B)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.4.1	Verify battery terminal voltage on float charge is: a. ≥ 126 V for the 125 V batteries; and b. ≥ 252 V for the 250 V battery.	7 days
SR 3.8.4.2	Verify no visible corrosion at battery terminals and connectors. OR Verify battery connection resistance is ≤ 24.4 E-6 ohms for inter-cell connectors of the Division 1 and 2 batteries, ≤ 169 E-6 ohms for inter-cell connectors of the Division 3 battery, and ≤ 20% above the resistance as measured during installation for inter-tier and inter-rack connectors.	92 days
SR 3.8.4.3	Verify battery cells, cell plates, and racks show no visual indication of physical damage or abnormal deterioration that degrades battery performance.	12 months
SR 3.8.4.4	Remove visible corrosion, and verify battery cell to cell and terminal connections are coated with anti-corrosion material.	12 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.4.5	Verify battery connection resistance is ≤ 24.4 E-6 ohms for inter-cell connectors of the Division 1 and 2 batteries, ≤ 169 E-6 ohms for inter-cell connectors of the Division 3 battery, and ≤ 20% above the resistance as measured during installation for inter-tier and inter-rack connectors.	12 months
SR 3.8.4.6	Verify each required battery charger supplies the required load for ≥ 1.5 hours at: a. ≥ 126 V for the 125 V battery chargers; and b. ≥ 252 V for the 250 V battery charger.	24 months
SR 3.8.4.7	----------NOTES---------- 1. The modified performance discharge test in SR 3.8.4.8 may be performed in lieu of the service test in SR 3.8.4.7 once per 60 months. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify battery capacity is adequate to supply, and maintain in OPERABLE status, the required emergency loads for the design duty cycle when subjected to a battery service test.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.4.8	----------NOTE---------- This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ----------	
	Verify battery capacity is ≥ 80% of the manufacturer's rating for the 125 V batteries and ≥ 83.4% of the manufacturer's rating for the 250 V battery, when subjected to a performance discharge test or a modified performance discharge test.	60 months AND 12 months when battery shows degradation or has reached 85% of expected life with capacity < 100% of manufacturer's rating AND 24 months when battery has reached 85% of the expected life with capacity ≥ 100% of manufacturer's rating

(B)

3.9 REFUELING OPERATIONS

3.9.1 Refueling Equipment Interlocks

LCO 3.9.1 The refueling equipment interlocks associated with the refuel position shall be OPERABLE. (B)

APPLICABILITY: During in-vessel fuel movement with equipment associated with the interlocks when the reactor mode switch is in the refuel position. (B)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required refueling equipment interlocks inoperable.	A.1 Suspend in-vessel fuel movement with equipment associated with the inoperable interlock(s).	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.1.1	Perform CHANNEL FUNCTIONAL TEST on each of the following required refueling equipment interlock inputs: a. All-rods-in, b. Refueling platform position, c. Refueling platform fuel grapple fuel-loaded, d. Refueling platform frame-mounted hoist fuel-loaded, and e. Refueling platform trolley-mounted hoist fuel-loaded.	7 days

3.9 REFUELING OPERATIONS

3.9.2 Refuel Position One-Rod-Out Interlock

LCO 3.9.2 The refuel position one-rod-out interlock shall be OPERABLE.

APPLICABILITY: MODE 5 with the reactor mode switch in the refuel position and any control rod withdrawn.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Refuel position one-rod-out interlock inoperable.	A.1 Suspend control rod withdrawal. AND	Immediately
	A.2 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.2.1	Verify reactor mode switch locked in refuel position.	12 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.9.2.2	----------NOTE---------- Not required to be performed until 1 hour after any control rod is withdrawn. ---------- Perform CHANNEL FUNCTIONAL TEST.	7 days

3.9 REFUELING OPERATIONS

3.9.3 Control Rod Position

LCO 3.9.3 All control rods shall be fully inserted.

APPLICABILITY: When loading fuel assemblies into the core.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more control rods not fully inserted.	A.1 Suspend loading fuel assemblies into the core.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.3.1	Verify all control rods are fully inserted.	12 hours

3.9 REFUELING OPERATIONS

3.9.4 Control Rod Position Indication

LCO 3.9.4 Each control rod "full-in" position indication channel shall be OPERABLE.

APPLICABILITY: MODE 5.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each required channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required control rod position indication channels inoperable.	A.1.1 Suspend in-vessel fuel movement.	Immediately
	AND	
	A.1.2 Suspend control rod withdrawal.	Immediately
	AND	
	A.1.3 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately
	OR	
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.1 Initiate action to fully insert the control rod associated with the inoperable position indicator. AND A.2.2 Initiate action to disarm the control rod drive associated with the fully inserted control rod.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.4.1	Verify each channel has no "full-in" indication on each control rod that is not "full-in."	Each time the control rod is withdrawn from the "full-in" position

3.9 REFUELING OPERATIONS

3.9.5 Control Rod OPERABILITY—Refueling

LCO 3.9.5 Each withdrawn control rod shall be OPERABLE.

APPLICABILITY: MODE 5.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more withdrawn control rods inoperable.	A.1 Initiate action to fully insert inoperable withdrawn control rods.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.5.1	----------NOTE---------- Not required to be performed until 7 days after the control rod is withdrawn. ---------- Insert each withdrawn control rod at least one notch.	7 days
SR 3.9.5.2	Verify each withdrawn control rod scram accumulator pressure is ≥ 940 psig.	7 days

3.9 REFUELING OPERATIONS

3.9.6 Reactor Pressure Vessel (RPV) Water Level – Irradiated Fuel

LCO 3.9.6 RPV water level shall be ≥ 22 ft above the top of the RPV flange.

APPLICABILITY: During movement of irradiated fuel assemblies within the RPV.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RPV water level not within limit.	A.1 Suspend movement of irradiated fuel assemblies within the RPV.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.6.1	Verify RPV water level is ≥ 22 ft above the top of the RPV flange.	24 hours

3.9 REFUELING OPERATIONS

3.9.7 Reactor Pressure Vessel (RPV) Water Level—New Fuel or Control Rods

LCO 3.9.7 RPV water level shall be ≥ 22 ft above the top of irradiated fuel assemblies seated within the RPV.

APPLICABILITY: During movement of new fuel assemblies or handling of control rods within the RPV when irradiated fuel assemblies are seated within the RPV.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RPV water level not within limit.	A.1 Suspend movement of new fuel assemblies and handling of control rods within the RPV.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.7.1	Verify RPV water level is ≥ 22 ft above the top of irradiated fuel assemblies seated within the RPV.	24 hours

3.9 REFUELING OPERATIONS

3.9.8 Residual Heat Removal (RHR)—High Water Level

LCO 3.9.8 One RHR shutdown cooling subsystem shall be OPERABLE and in operation.

---NOTE---
The required RHR shutdown cooling subsystem may be removed from operation for up to 2 hours per 8 hour period.

APPLICABILITY: MODE 5 with irradiated fuel in the reactor pressure vessel (RPV) and with the water level ≥ 22 ft above the top of the RPV flange.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required RHR shutdown cooling subsystem inoperable.	A.1 Verify an alternate method of decay heat removal is available.	1 hour AND Once per 24 hours thereafter
B. Required Action and associated Completion Time of Condition A not met.	B.1 Suspend loading irradiated fuel assemblies into the RPV. AND B.2 Initiate action to restore secondary containment to OPERABLE status. AND	Immediately Immediately (continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.3	Initiate action to restore one standby gas treatment subsystem to OPERABLE status.	Immediately
	AND		
	B.4	Initiate action to restore isolation capability in each required secondary containment penetration flow path not isolated.	Immediately
C. No RHR shutdown cooling subsystem in operation.	C.1	Verify reactor coolant circulation by an alternate method.	1 hour from discovery of no reactor coolant circulation AND Once per 12 hours thereafter
	AND		
	C.2	Monitor reactor coolant temperature.	Once per hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.8.1	Verify one RHR shutdown cooling subsystem is operating.	12 hours

3.9 REFUELING OPERATIONS

3.9.9 Residual Heat Removal (RHR) – Low Water Level

LCO 3.9.9 Two RHR shutdown cooling subsystems shall be OPERABLE, and one RHR shutdown cooling subsystem shall be in operation.

---NOTE---
The required operating shutdown cooling subsystem may be removed from operation for up to 2 hours per 8 hour period.

APPLICABILITY: MODE 5 with irradiated fuel in the reactor pressure vessel (RPV) and with the water level < 22 ft above the top of the RPV flange.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or two RHR shutdown cooling subsystems inoperable.	A.1 Verify an alternate method of decay heat removal is available for each inoperable RHR shutdown cooling subsystem.	1 hour AND Once per 24 hours thereafter
B. Required Action and associated Completion Time of Condition A not met.	B.1 Initiate action to restore secondary containment to OPERABLE status. AND	Immediately (continued)

ACTIONS.

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.2 Initiate action to restore one standby gas treatment subsystem to OPERABLE status. AND B.3 Initiate action to restore isolation capability in each required secondary containment penetration flow path not isolated.	Immediately Immediately
C. No RHR shutdown cooling subsystem in operation.	C.1 Verify reactor coolant circulation by an alternate method. AND C.2 Monitor reactor coolant temperature.	1 hour from discovery of no reactor coolant circulation AND Once per 12 hours thereafter Once per hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.9.1	Verify one RHR shutdown cooling subsystem is operating.	12 hours

3.10 SPECIAL OPERATIONS

3.10.4 Single Control Rod Withdrawal—Cold Shutdown

LCO 3.10.4 The reactor mode switch position specified in Table 1.1-1 for MODE 4 may be changed to include the refuel position, and operation considered not to be in MODE 2, to allow withdrawal of a single control rod, and subsequent removal of the associated control rod drive (CRD) if desired, provided the following requirements are met:

a. All other control rods are fully inserted;

b. 1. LCO 3.9.2, "Refuel Position One-Rod-Out Interlock," and

LCO 3.9.4, "Control Rod Position Indication,"

OR

2. A control rod withdrawal block is inserted; and

c. 1. LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," MODE 5 requirements for Functions 1.a, 1.b, 7.a, 7.b, 10, and 11 of Table 3.3.1.1-1,

LCO 3.3.8.2, "Reactor Protection System (RPS) Electric Power Monitoring," MODE 5 requirements, and

LCO 3.9.5, "Control Rod OPERABILITY—Refueling,"

OR

2. All other control rods in a five by five array centered on the control rod being withdrawn are disarmed, at which time LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," MODE 5 requirements may be changed to allow the single control rod withdrawn to be assumed to be the highest worth control rod.

APPLICABILITY: MODE 4 with the reactor mode switch in the refuel position.

5.5 Programs and Manuals

5.5.7 Ventilation Filter Testing Program (VFTP) (continued)

c. Demonstrate for each of the ESF systems that a laboratory test of a sample of the charcoal adsorber, when obtained as described in Regulatory Guide 1.52, Revision 2, Section C.6.b shows the methyl iodide penetration less than the value specified below when tested in accordance with ASTM D3803-1986 (Method B for the SGT System and Method A for the CREF System) at a relative humidity greater than or equal to the value specified below: | B

ESF Ventilation System	Penetration (%)	RH (%)
SGT System	0.175	70
CREF System	1.0	70

d. Demonstrate for each of the ESF systems that the pressure drop across the combined HEPA filters and the charcoal adsorbers is less than the value specified below when tested at the system flowrate specified below:

ESF Ventilation System	Delta P (inches wg)	Flowrate (cfm)
SGT System	< 8	4012 to 4902
CREF System	< 6	900 to 1100

e. Demonstrate that the heaters for each of the ESF systems dissipate the nominal value specified below when tested in accordance with ANSI N510-1989, Section 14.5.1:

ESF Ventilation System	Wattage (kW)
SGT System	18.6 to 22.8
CREF System	4.5 to 5.5

5.5.8 Explosive Gas and Storage Tank Radioactivity Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the Main Condenser Offgas Treatment System and the quantity of radioactivity contained in unprotected outdoor liquid storage tanks.

The program shall include:

(continued)

5.5 Programs and Manuals

5.5.8 Explosive Gas and Storage Tank Radioactivity Monitoring Program (continued)

a. The limits for concentrations of hydrogen in the Main Condenser Offgas Treatment System and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion); and

b. A surveillance program to ensure that the quantity of radioactivity contained in all outside temporary liquid radwaste tanks that are not surrounded by liners, dikes, or walls, capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the Liquid Radwaste Treatment System is less than the amount that would result in concentrations greater than the limits of Appendix B, Table 2, Column 2 to 10 CFR 20.1001 - 20.2402, at the nearest potable water supply and the nearest surface water supply in an unrestricted area, in the event of an uncontrolled release of the tanks' contents. (B)

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program Surveillance Frequencies.

5.5.9 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program shall establish the required testing of both new fuel oil and stored fuel oil. The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with procedures based on applicable ASTM Standards. The purpose of the program is to establish the following:

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

1. An API gravity, a specific gravity, or an absolute specific gravity within limits,

2. A kinematic viscosity, when required, and a flash point within limits for ASTM 2-D fuel oil,

(continued)

5.5 Programs and Manuals

5.5.9 Diesel Fuel Oil Testing Program (continued)

3. A water and sediment content within limits or a clear and bright appearance with proper color;

b. Other properties for ASTM 2-D fuel oil are within limits within 31 days following sampling and addition to storage tanks; and

c. Total particulate concentration of the fuel oil in the storage tanks is ≤ 10 mg/l when tested every 31 days.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel Fuel Oil Testing Program test Frequencies. (B)

5.5.10 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases to these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not involve either of the following:

1. A change in the TS incorporated in the license; or

2. A change to the FSAR or Bases that involves an unreviewed safety question as defined in 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the FSAR.

d. Proposed changes that meet the criteria of 5.5.10.b above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

(continued)

5.5 Programs and Manuals

5.5.11 Safety Function Determination Program (SFDP) (continued)

c. The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

5.5.12 Primary Containment Leakage Rate Testing Program

The Primary Containment Leakage Rate Testing Program shall establish the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995, as modified by the following exception: Compensation for flow meter inaccuracies in excess of those specified in ANSI/ANS 56.8-1994 will be accomplished by increasing the actual instrument reading by the amount of the full scale inaccuracy when assessing the effect of local leak rates against the criteria established in Specification 5.5.12.a.

The peak calculated primary containment internal pressure for the design basis loss of coolant accident, P_a, is 38 psig.

The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 0.5% of primary containment air weight per day.

Leakage rate acceptance criteria are:

a. Primary containment leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $< 0.60\ L_a$ for the Type B and Type C tests (except for main steam isolation valves) and $< 0.75\ L_a$ for Type A tests;

(continued)

5.5 Programs and Manuals

5.5.12 Primary Containment Leakage Rate Testing Program (continued)

b. Primary containment air lock testing acceptance criteria are:

1) Overall primary containment air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$; and

2) For each door, leakage rate is $\leq 0.025\ L_a$ when pressurized to ≥ 10 psig.

The provisions of SR 3.0.3 are applicable to the Primary Containment Leakage Rate Testing Program.

(2)

5.0 ADMINISTRATIVE CONTROLS

5.6 Reporting Requirements

The following reports shall be submitted in accordance with 10 CFR 50.4.

5.6.1 Occupational Radiation Exposure Report

A tabulation on an annual basis of the number of station, utility, and other personnel (including contractors) receiving exposures > 100 mrem/yr and their associated man rem exposure according to work and job functions (e.g., reactor operations and surveillance, inservice inspection, routine maintenance, special maintenance (describe maintenance), waste processing, and refueling). This tabulation supplements the requirements of 10 CFR 20.407. The dose assignments to various duty functions may be estimated based on electronic or pocket dosimeter, thermoluminescent dosimeter (TLD), or film badge measurements. Small exposures totalling < 20% of the individual total dose need not be accounted for. In the aggregate, at least 80% of the total whole body dose received from external sources should be assigned to specific major work functions. The report shall be submitted by April 30 of each year.

5.6.2 Annual Radiological Environmental Operating Report

The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted by May 15 of each year. The report shall include summaries, interpretations, and analyses of trends of the results of the Radiological Environmental Monitoring Program for the reporting period. The material provided shall be consistent with the objectives outlined in the Offsite Dose Calculation Manual (ODCM), and in 10 CFR 50, Appendix I, Sections IV.B.2, IV.B.3, and IV.C.

The Annual Radiological Environmental Operating Report shall include the results of analyses of all radiological environmental samples and of all environmental radiation measurements taken during the period pursuant to the locations specified in the table and figures in the ODCM, as well as summarized and tabulated results of these analyses and measurements in the format of the table in the Radiological Assessment Branch Technical Position, Revision 1, November 1979. In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting and explaining the reasons for the missing results. The missing data shall be submitted in a supplementary report as soon as possible.

(continued)

5.6 Reporting Requirements (continued)

5.6.3 Radioactive Effluent Release Report

The Radioactive Effluent Release Report covering the operation of the unit shall be submitted in accordance with 10 CFR 50.36a. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be consistent with the objectives outlined in the ODCM and the Process Control Program and in conformance with 10 CFR 50.36a and 10 CFR 50, Appendix I, Section IV.B.1.

5.6.4 Monthly Operating Reports

Routine reports of operating statistics and shutdown experience, including documentation of all challenges to the safety/relief valves, shall be submitted on a monthly basis no later than the 15th of each month following the calendar month covered by the report.

5.6.5 CORE OPERATING LIMITS REPORT (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

   1. The APLHGR for Specification 3.2.1;

   2. The MCPR for Specification 3.2.2;

   3. The LHGR for Specification 3.2.3; and

   4. The power-to-flow map for Specification 3.4.1.

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

   1. ANF-1125(P)(A), and Supplements 1 and 2, "ANFB Critical Power Correlation," April 1990;

   2. Letter, R.C. Jones (NRC) to R.A. Copeland (ANF), "NRC Approval of ANFB Additive Constants for ANF 9x9-9X BWR Fuel," dated November 14, 1990;

(continued)

5.6 Reporting Requirements

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

3. ANF-NF-524(P)(A), Revision 2 and Supplements 1 and 2, "Advanced Nuclear Fuels Corporation Critical Power Methodology for Boiling Water Reactors," November 1990;

4. ANF-913(P)(A), Volume 1, Revision 1 and Volume 1, Supplements 2, 3, and 4, "COTRANSA 2: A Computer Program for Boiling Water Reactor Transient Analysis," August 1990;

5. ANF-CC-33(P)(A), Supplement 2, "HUXY: A Generalized Multirod Heatup Code with 10 CFR 50, Appendix K Heatup Option," January 1991;

6. XN-NF-80-19(P)(A), Volume 1, Supplements 3 and 4, "Advanced Nuclear Fuel Methodology for Boiling Water Reactors," November 1990;

7. XN-NF-80-19(P)(A), Volume 4, Revision 1, "Exxon Nuclear Methodology Boiling Water Reactors: Application of the ENC Methodology to BWR Reloads," June 1986;

8. XN-NF-80-19(P)(A), Volume 3, Revision 2, "Exxon Nuclear Methodology for Boiling Water Reactors THERMEX: Thermal Limits Methodology Summary Description," January 1987;

9. XN-NF-85-67(P)(A), Revision 1, "Generic Mechanical Design for Exxon Nuclear Jet Pump BWR Reload Fuel," September 1986;

10. ANF-89-014(P)(A), Revision 1 and Supplements 1 and 2, "Advanced Nuclear Fuels Corporation Generic Mechanical Design for Advanced Nuclear Fuels Corporation 9x9-IX and 9x9-9X BWR Reload Fuel," October 1991;

11. XN-NF-81-22(P)(A), "Generic Statistical Uncertainty Analysis Methodology," November 1983;

12. NEDE-24011-P-A-10-US, "General Electric Standard Application for Reactor Fuel," U.S. Supplement, March 1991;

(continued)

5.6 Reporting Requirements

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

13. NEDE-23785-1-PA, Revision 1, "The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident, Volume III, SAFER/GESTR Application Methodology," October 1984;

14. NEDO-20566A, "General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10 CFR 50, Appendix K," September 1986; and

15. EMF-CC-074(P)(A), "Volume 1 -- STAIF - A Computer Program for BWR Stability in the Frequency Domain, Volume 2 -- STAIF - A Computer Program for BWR Stability in the Frequency Domain, Code Qualification Report," July 1994.

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

5.6.6 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

a. RCS pressure and temperature limits for heatup, cooldown, low temperature operation, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR for Specification 3.4.12, "RCS Pressure and Temperature (P/T) Limits."

b. The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents: [identify documents].

c. The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplement thereto.

(continued)

5.6 Reporting Requirements (continued)

5.6.7 Post Accident Monitoring (PAM) Instrumentation Report

When a report is required by Condition B or F of LCO 3.3.3.1, "Post Accident Monitoring (PAM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

5.0 ADMINISTRATIVE CONTROLS

5.7 High Radiation Area

As provided in paragraph 20.1601(c) of 10 CFR Part 20, the following controls shall be applied to high radiation areas in place of the controls required by paragraph 20.1601(a) and (b) of 10 CFR Part 20.

5.7.1 High Radiation Areas with Dose Rates not Exceeding 1.0 rem/hour (at 30 centimeters from the radiation sources or from any surface penetrated by the radiation)

a. Each entryway to such an area shall be barricaded and conspicuously posted as a high radiation area. Such barricades may be opened as necessary to permit entry or exit of personnel or equipment. (A)

b. Access to, and activities in, each such area shall be controlled by means of a Radiation Work Permit (RWP) or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures (e.g., health physics technicians) and personnel continuously escorted by such individuals may be exempted from the requirement for an RWP or equivalent while performing their assigned duties provided that they are following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess: (B)

1. A radiation monitoring device that continuously displays radiation dose rates in the area ("radiation monitoring and indicating device");

2. A radiation monitoring device that continuously integrates the radiation dose rates in the area and alarms when the device's dose alarm setpoint is reached ("alarming dosimeter"), with an appropriate alarm setpoint;

3. A radiation monitoring device that continuously transmits dose rate and cumulative dose to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area; or

(continued)

5.7 High Radiation Area

5.7.1 High Radiation Areas with Dose Rates not Exceeding 1.0 rem/hour (at 30 centimeters from the radiation sources or from any surface penetrated by the radiation) (continued)

4. A self-reading dosimeter and,

   (a) Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual at the work site, qualified in radiation protection procedures, equipped with a radiation monitoring and indicating device who is responsible for controlling personnel radiation exposure within the area, or

   (b) Be under the surveillance, as specified in the RWP or equivalent, while in the area, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area.

e. Except for individuals qualified in radiation protection procedures, entry into such areas shall be made only after dose rates in the area have been established and entry personnel are knowledgeable of them. (E)

5.7.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour (at 30 centimeters from the radiation source or from any surface penetrated by the radiation), but less than 500 rads/hour (at 1 meter from the radiation source or from any surface penetrated by the radiation)

a. Each entryway to such an area shall be conspicuously posted as a high radiation area and shall be provided with a locked door, gate, or guard that prevents unauthorized entry, and in addition:

   1. All such door and gate keys shall be maintained under the administrative control of the Shift Manager or Health Physics supervision on duty; and

   2. Doors and gates shall remain locked or guarded except during periods of personnel entry or exit.

(continued)

5.7 High Radiation Area

5.7.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour (at 30 centimeters from the radiation source or from any surface penetrated by the radiation), but less than 500 rads/hour (at 1 meter from the radiation source or from any surface penetrated by the radiation) (continued)

b. Access to, and activities in, each such area shall be controlled by means of an RWP or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures may be exempted from the requirement for an RWP or equivalent while performing radiation surveys in such areas provided that they are following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess: (B)

1. An alarming dosimeter with an appropriate alarm setpoint;

2. A radiation monitoring device that continuously transmits dose rate and cumulative dose to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area with the means to communicate with and control every individual in the area; (B)

3. A self-reading dosimeter and,

(a) Be under the surveillance, as specified in the RWP or equivalent, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring and indicating device who is responsible for controlling personnel exposure within the area, or

(b) Be under the surveillance, as specified in the RWP or equivalent, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with and control every individual in the area; or (B)

(continued)

5.7 High Radiation Area

5.7.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour (at 30 centimeters from the radiation source or from any surface penetrated by the radiation), but less than 500 rads/hour (at 1 meter from the radiation source or from any surface penetrated by the radiation) (continued)

4. A radiation monitoring and indicating device in those cases where the options of Specification 5.7.2.d.2 and 5.7.2.d.3, above, are impractical or determined to be inconsistent with the "As Low As is Reasonably Achievable" principle.

e. Except for individuals qualified in radiation protection procedures, entry into such areas shall be made only after dose rates in the area have been established and entry personnel are knowledgeable of them.

f. Such individual areas that are within a larger area that is controlled as a high radiation area, where no enclosure exists for purpose of locking and where no enclosure can reasonably be constructed around the individual area need not be controlled by a locked door or gate, but shall be barricaded and conspicuously posted as a high radiation area, and a conspicuous, clearly visible flashing light shall be activated at the area as a warning device.

BASES (continued)

SAFETY LIMIT VIOLATIONS

Exceeding an SL may cause fuel damage and create a potential for radioactive releases in excess of 10 CFR 100, "Reactor Site Criteria," limits (Ref. 4). Therefore, it is required to insert all insertable control rods and restore compliance with the SL within 2 hours. The 2 hour Completion Time ensures that the operators take prompt remedial action and the probability of an accident occurring during this period is minimal. (B)

REFERENCES

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

2. ANF-1125(P)(A), Revision 0, including Supplements 1 and 2, April 1990.

3. ANF-524(P)(A), Revision 2, including Supplements 1 and 2, November 1990.

4. 10 CFR 100. (B)

B 2.0 SAFETY LIMITS (SLs)

B 2.1.2 Reactor Coolant System (RCS) Pressure SL

BASES

BACKGROUND

The SL on reactor steam dome pressure protects the RCS against overpressurization. In the event of fuel cladding failure, fission products are released into the reactor coolant. The RCS then serves as the primary barrier in preventing the release of fission products into the atmosphere. Establishing an upper limit on reactor steam dome pressure ensures continued RCS integrity. According to 10 CFR 50, Appendix A, GDC 14, "Reactor Coolant Pressure Boundary," and GDC 15, "Reactor Coolant System Design" (Ref. 1), the reactor coolant pressure boundary (RCPB) shall be designed with sufficient margin to ensure that the design conditions are not exceeded during normal operation and anticipated operational occurrences (AOOs).

During normal operation and AOOs, RCS pressure is limited from exceeding the design pressure by more than 10%, in accordance with Section III of the ASME Code (Ref. 2). To ensure system integrity, all RCS components are hydrostatically tested at 125% of design pressure, in accordance with ASME Code requirements, prior to initial operation when there is no fuel in the core. Any further hydrostatic testing with fuel in the core may be done under LCO 3.10.1, "Inservice Leak and Hydrostatic Testing Operation." Following inception of unit operation, RCS components shall be pressure tested in accordance with the requirements of ASME Code, Section XI (Ref. 3).

Overpressurization of the RCS could result in a breach of the RCPB reducing the number of protective barriers designed to prevent radioactive releases from exceeding the limits specified in 10 CFR 100, "Reactor Site Criteria" (Ref. 4). If this occurred in conjunction with a fuel cladding failure, the number of protective barriers designed to prevent radioactive releases from exceeding the limits would be reduced.

The RCS safety/relief valves and the Reactor Protection System Reactor Vessel Steam Dome Pressure—High Function have settings established to ensure that the RCS pressure SL will not be exceeded.

(continued)

BASES

BACKGROUND (continued)

The RCS pressure SL has been selected such that it is at a pressure below which it can be shown that the integrity of the system is not endangered. The reactor pressure vessel is designed to ASME, Boiler and Pressure Vessel Code, Section III, 1971 Edition, including Addenda through the summer of 1971 (Ref. 5), which permits a maximum pressure transient of 110%, 1375 psig, of design pressure 1250 psig. The SL of 1325 psig, as measured in the reactor steam dome, is equivalent to 1375 psig at the lowest elevation of the RCS. The RCS is designed to ASME Code, Section III, 1971 Edition, including Addenda through the summer of 1971 (Ref. 5), for the reactor recirculation piping, which permits a maximum pressure transient of 125% of design pressures of 1250 psig for suction piping and 1550 psig for discharge piping. The RCS pressure SL is selected to be the lowest transient overpressure allowed by the applicable codes.

SAFETY LIMITS

The maximum transient pressure allowable in the RCS pressure vessel under the ASME Code, Section III, is 110% of design pressure. The maximum transient pressure allowable in the RCS piping, valves, and fittings is 125% of design pressures of 1250 psig for suction piping and 1550 psig for discharge piping. The most limiting of these allowances is the 110% of design pressure; therefore, the SL on maximum allowable RCS pressure is established at 1325 psig as measured at the reactor steam dome.

APPLICABILITY

SL 2.1.2 applies in all MODES.

SAFETY LIMIT VIOLATIONS

Exceeding the RCS pressure SL may cause RCS failure and create a potential for radioactive releases in excess of 10 CFR 100, "Reactor Site Criteria," limits (Ref. 4). Therefore, it is required to insert all insertable control rods and restore compliance with the SL within 2 hours. The 2 hour Completion Time ensures that the operators take prompt remedial action and the probability of an accident occurring during this period is minimal. (B)

(B)

(continued)

BASES (continued)

REFERENCES

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

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

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

4. 10 CFR 100.

5. ASME, Boiler and Pressure Vessel Code, 1971 Edition, Addenda, summer of 1971.

(B)

BASES

SR 3.0.2 (continued)

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. The requirements of regulations take precedence over the TS. Therefore, when a test interval is specified in the regulations, the test interval cannot be extended by the TS, and the SR includes a Note in the Frequency stating, "SR 3.0.2 is not applicable." B

As stated in SR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per..." basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required Action, whether it is a particular Surveillance or some other remedial action, is considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner.

The provisions of SR 3.0.2 are not intended to be used repeatedly merely as an operational convenience to extend Surveillance intervals (other than those consistent with refueling intervals) or periodic Completion Time intervals beyond those specified.

SR 3.0.3

SR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified Frequency. A delay period of up to 24 hours or up to the limits of the specified Frequency, whichever is less, applies from the point in time it is discovered that the Surveillance has not been performed in accordance with SR 3.0.2, and not at the time that the specified Frequency was not met. This delay period provides adequate time to complete Surveillances that

(continued)

BASES

SR 3.0.3 (continued)

have been missed. This delay period permits the completion of a Surveillance before complying with Required Actions or other remedial measures that might preclude completion of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements.

When a Surveillance with a Frequency based not on time intervals, but upon specified unit conditions or operational situations, is discovered not to have been performed when specified, SR 3.0.3 allows the full delay period of 24 hours to perform the Surveillance.

SR 3.0.3 also provides a time limit for completion of Surveillances that become applicable as a consequence of MODE changes imposed by Required Actions.

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable then is considered outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the Completion Time of the ACTIONS, restores compliance with SR 3.0.1.

(continued)

BASES

LCO (continued)

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

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

APPLICABILITY

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

ACTIONS

A.1

If the APRM gain or Flow Biased Simulated Thermal Power–High Function Allowable Value is not within limits while the MFLPD has exceeded FRTP, the margin to the fuel cladding integrity SL and the fuel cladding 1% plastic strain limit may be reduced. Therefore, prompt action should be taken to

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The individual Functions are required to be OPERABLE in the MODES or other specified conditions specified in the Table that may require an RPS trip to mitigate the consequences of a design basis accident or transient. To ensure a reliable scram function, a combination of Functions is required in each MODE to provide primary and diverse initiation signals.

The only MODES specified in Table 3.3.1.1-1 are MODES 1 and 2, and MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies. No RPS Function is required in MODES 3 and 4 since all control rods are fully inserted and the Reactor Mode Switch Shutdown Position control rod withdrawal block (LCO 3.3.2.1) does not allow any control rod to be withdrawn. In MODE 5, control rods withdrawn from a core cell containing no fuel assemblies do not affect the reactivity of the core and, therefore, are not required to have the capability to scram. Provided all other control rods remain inserted, no RPS Function is required. In this condition, the required SDM (LCO 3.1.1) and refuel position one-rod-out interlock (LCO 3.9.2) ensure that no event requiring RPS will occur. (B)

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

1.a. Intermediate Range Monitor (IRM) Neutron Flux–High

The IRMs monitor neutron flux levels from the upper range of the source range monitors (SRMs) to the lower range of the average power range monitors (APRMs). The IRMs are capable of generating trip signals that can be used to prevent fuel damage resulting from abnormal operating transients in the intermediate power range. In this power range, the most significant source of reactivity change is due to control rod withdrawal. The IRM provides diverse protection from the rod worth minimizer (RWM), which monitors and controls the movement of control rods at low power. The RWM prevents the withdrawal of an out of sequence control rod during startup that could result in an unacceptable neutron flux excursion (Ref. 7). The IRM provides mitigation of the neutron flux excursion. To demonstrate the capability of the IRM System to mitigate control rod withdrawal events, a generic analysis has been performed (Ref. 8) to evaluate the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.5 and SR 3.3.1.1.6 (continued)

If overlap for a group of channels is not demonstrated (e.g., IRM/APRM overlap), the reason for the failure of the Surveillance should be determined and the appropriate channel(s) declared inoperable. Only those appropriate channel(s) that are required in the current MODE or condition should be declared inoperable.

A Frequency of 7 days is reasonable based on engineering judgment and the reliability of the IRMs and APRMs.

SR 3.3.1.1.7

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the APRM System. The 1130 MWD/T Frequency is based on operating experience with LPRM sensitivity changes. (B)

SR 3.3.1.1.8 and SR 3.3.1.1.13

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

For Function 2.b, the CHANNEL FUNCTIONAL TEST includes the adjustment of the APRM channel to conform to a calibrated flow signal. This ensures that the total loop drive flow signals from the flow unit used to vary the setpoint are appropriately compared to an injection test flow signal to verify the flow signal trip setpoint and, therefore, the APRM Function accurately reflects the required setpoint as a function of flow. If the flow signal trip setpoint is not within the appropriate limit, the APRMs that receive an input from the inoperable flow unit must be declared inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.2.7

Performance of a CHANNEL CALIBRATION verifies the performance of the SRM detectors and associated circuitry. The Frequency considers the plant conditions required to perform the test, the ease of performing the test, and the likelihood of a change in the system or component status. The neutron detectors are excluded from the CHANNEL CALIBRATION (Note 1) because they cannot readily be adjusted. The detectors are fission chambers that are designed to have a relatively constant sensitivity over the range, and with an accuracy specified for a fixed useful life.

Note 2 to the Surveillance allows the Surveillance to be delayed until entry into the specified condition of the Applicability. The SR must be performed in MODE 2 within 12 hours of entering MODE 2 with IRMs on Range 2 or below. The allowance to enter the Applicability with the 18 month Frequency not met is reasonable, based on the limited time of 12 hours allowed after entering the Applicability and the inability to perform the Surveillance while at higher power levels. Although the Surveillance could be performed while on IRM Range 3, the plant would not be expected to maintain steady state operation at this power level. In this event, the 12 hour Frequency is reasonable, based on the SRMs being otherwise verified to be OPERABLE (i.e., satisfactorily performing the CHANNEL CHECK) and the time required to perform the Surveillances.

REFERENCES None.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.2.1 (continued)

something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. As specified in the Surveillance, a CHANNEL CHECK is only required for those channels that are normally energized.

The Frequency is based upon plant operating experience that demonstrates channel failure is rare.

SR 3.3.3.2.2 and SR 3.3.3.2.3 (A)

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

The 18 month Frequency of SR 3.3.3.2.2 is based upon operating experience and is consistent with the typical industry refueling cycle. (B) The 24 month Frequency of SR 3.3.3.2.3 is based upon operating experience and engineering judgment. (A)

SR 3.3.3.2.4 (A)

SR 3.3.3.2.4 verifies each required Remote Shutdown System transfer switch and control circuit performs the intended function. (B) This verification is performed from the remote and alternate shutdown panels, as appropriate. Operation of the equipment from the remote shutdown panel or alternate remote 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 plant can be placed and maintained in MODE 3 from the remote or alternate shutdown panels. The 24 month Frequency

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.2.4 (continued)

is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience demonstrates that Remote Shutdown System controls usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

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

2. "Final Policy Statement on Technical Specifications Improvements," July 22, 1993 (58 FR 39132).

3. Licensee Controlled Specifications Manual.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1.1 (continued)

between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

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

SR 3.3.5.1.2

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

The Frequency of 92 days is based on the reliability analyses of Reference 7.

SR 3.3.5.1.3, SR 3.3.5.1.4, and SR 3.3.5.1.5

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1.3, SR 3.3.5.1.4, and SR 3.3.5.1.5 (continued)

The Frequencies are based upon the assumption of a 92 day, 18 month, or 24 month calibration interval, as applicable, in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.5.1.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.5.1, LCO 3.5.2, LCO 3.8.1, and LCO 3.8.2 overlaps this Surveillance to provide complete testing of the assumed safety function.

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

REFERENCES

1. FSAR, Section 5.2.
2. FSAR, Section 6.3.
3. FSAR, Chapter 15.
4. FSAR, Section 15.F.6.
5. NEDC-32115P, "Washington Public Power Supply System Nuclear Project 2, SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," July 1993.
6. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
7. NEDC-30936-P-A, "BWR Owners' Group Technical Specification Improvement Analyses for ECCS Actuation Instrumentation, Part 2," December 1988.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.e, 1.f, 1.g, 2.c, 2.d. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) (continued)

equipment. The Time Delay Allowable Values are long enough to provide time for the offsite power supply to recover to normal voltages, but short enough to ensure that sufficient power is available to the required equipment.

Three channels of the Division 1 and 2 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)—4.16 kV Basis and —Primary Time Delay Functions per associated emergency bus are available, but only two channels of Division 1 and 2 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)—4.16 kV Basis and —Primary Time Delay Functions per associated emergency bus are required to be OPERABLE when the associated DG is required to be OPERABLE. One channel of Division 1 and 2 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)—Secondary Time Delay Function per associated emergency bus is available and required to be OPERABLE when the associated DG is required to be OPERABLE. Two channels of Division 3 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) Function and Time Delay Function are available and required to be OPERABLE when the associated DG is required to be OPERABLE. These requirements ensure that no single instrument failure can preclude the DG function. Note (a) has been added for the Division 1 and 2 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) protection requirements to ensure the required Degraded Voltage—4.16 kV Basis and —Primary Time Delay Functions are associated with one another, since only two of the available channels for each Function are required to be OPERABLE. Refer to LCO 3.8.1 and LCO 3.8.2 for Applicability Bases for the DGs.

ACTIONS

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

(continued)

BASES

ACTIONS (continued)

such, a Note has been provided that allows separate Condition entry for each inoperable LOP instrumentation channel.

A.1

With one or more channels of a Function inoperable, the Function may not be capable of performing the intended function. Therefore, only 1 hour is allowed to restore the inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the channel in trip would result in a bus transfer and DG initiation), Condition B must be entered and its Required Action taken.

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

B.1, B.2.1, and B.2.2 (B)

If any Required Action and associated Completion Time is not met, the associated Function may not be capable of performing the intended function. Therefore, the associated DG(s) are declared inoperable immediately (Required Action B.1). (B) This requires entry into applicable Conditions and Required Actions of LCO 3.8.1 and LCO 3.8.2, which provide appropriate actions for the inoperable DG(s). Alternately, for Functions 1.c and 1.d only, the TR-B loss of voltage instrumentation, the offsite circuit supply breaker to the associated 4.16 kV ESF bus must be opened immediately (Required Action B.2.1) and the associated offsite circuit declared inoperable immediately (Required Action B.2.2). (B) These alternate Required Actions also provide appropriate compensatory measures since the TR-B loss of voltage instrumentation only affects the loss of voltage trip capability of the alternate offsite circuit.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each LOP Instrumentation Function are located in the SRs column of Table 3.3.8.1-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 2 hours provided the associated Function maintains initiation capability. Initiation capability is maintained provided the following can be initiated by the Function (i.e., Loss of Voltage and Degraded Voltage) for two of the three DGs and 4.16 kV ESF buses: DG start, disconnect from the offsite power source, transfer to the alternate offsite power source, if available, DG output breaker closure, and load shed. Upon completion of the Surveillance, or expiration of the 2 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken.

SR 3.3.8.1.1

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. Any setpoint adjustments shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 31 days is based on plant operating experience with regard to channel OPERABILITY and drift that demonstrates that failure of more than one channel of a given Function in any 31 day interval is rare.

SR 3.3.8.1.2 and SR 3.3.8.1.3 (B)

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1.2 and SR 3.3.8.1.3 (continued) (B)

The Frequencies are based on the assumption of an 18 month or 24 month calibration interval, as applicable, in the determination of the magnitude of equipment drift in the setpoint analysis. (B) (B)

SR 3.3.8.1.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required actuation logic for a specific channel. The system functional testing performed in LCO 3.8.1 and LCO 3.8.2 overlaps this Surveillance to provide complete testing of the assumed safety functions.

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

REFERENCES

1. FSAR, Section 8.3.1.1.1.
2. FSAR, Section 5.2.
3. FSAR, Section 6.3.
4. FSAR, Chapter 15.
5. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

BASES

BACKGROUND (continued)

Class 1E overvoltage, undervoltage, and underfrequency sensing logic. Together, a circuit breaker and its sensing logic constitute an electric power monitoring assembly. If the output of the MG set or the alternate power supply exceeds the predetermined limits of overvoltage, undervoltage, or underfrequency, a trip coil driven by this logic circuitry opens the circuit breaker, which removes the associated power supply from service.

APPLICABLE SAFETY ANALYSES

RPS electric power monitoring is necessary to meet the assumptions of the safety analyses by ensuring that the equipment powered from the RPS buses can perform its intended function. RPS electric power monitoring provides protection to the RPS and other systems that receive power from the RPS buses, by disconnecting the RPS from the power supply under specified conditions that could damage the RPS bus powered equipment.

RPS electric power monitoring satisfies Criterion 3 of the NRC Policy Statement (Ref. 2).

LCO

The OPERABILITY of each RPS electric power monitoring assembly is dependent upon the OPERABILITY of the overvoltage, undervoltage, and underfrequency logic, as well as the OPERABILITY of the associated circuit breaker. Two electric power monitoring assemblies are required to be OPERABLE for each inservice power supply that supports equipment required to be OPERABLE (i.e., if the inservice power supply is not supporting any equipment required to be OPERABLE by Technical Specifications, then the associated electric power monitoring assemblies are not required to be OPERABLE). This provides redundant protection against any abnormal voltage or frequency conditions to ensure that no single RPS electric power monitoring assembly failure can preclude the function of RPS bus powered components. Each of the inservice electric power monitoring assembly trip logic setpoints is required to be within the specific Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each RPS electric power monitoring assembly trip logic (refer to SR 3.3.8.2.2). Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between

(continued)

BASES

LCO (continued)

CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., overvoltage), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip relay) changes state. The analytic limits are derived from the limiting values of the process parameters, including associated line losses, obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for process and all instrument uncertainties, except drift and calibration. The trip setpoints are derived from the analytic limits, corrected for process, and all instrument uncertainties, including drift and calibration. The trip setpoints derived in this manner provide adequate protection because all instrumentation uncertainties and process effects are taken into account.

The Allowable Values for the instrument settings are based on the RPS providing $\geq$ 57 Hz, 120 V $\pm$ 10% (to all equipment), and 115 V $\pm$ 10 V (to scram and MSIV solenoids). The most limiting voltage requirement determines the settings of the electric power monitoring instrument channels. The settings are calculated based on the loads on the buses and RPS MG set or alternate power supply being 120 VAC and 60 Hz.

APPLICABILITY

The operation of the RPS electric power monitoring assemblies is essential to disconnect the RPS bus powered components from the MG set or alternate power supply during abnormal voltage or frequency conditions. Since the degradation of a nonclass 1E source supplying power to the RPS bus can occur as a result of any random single failure, the OPERABILITY of the RPS electric power monitoring assemblies is required when the RPS bus powered components are required to be OPERABLE. This results in the RPS Electric Power Monitoring System OPERABILITY being required in MODES 1, 2, and 3, MODES 4 and 5 with both residual heat removal (RHR) shutdown cooling suction isolation valves open, and MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies. (B)

(continued)

BASES (continued)

ACTIONS

A.1

If one RPS electric power monitoring assembly for an inservice power supply (MG set or alternate) is inoperable, or one RPS electric power monitoring assembly on each inservice power supply is inoperable, the OPERABLE assembly will still provide protection to the RPS bus powered components under degraded voltage or frequency conditions. However, the reliability and redundancy of the RPS Electric Power Monitoring System are reduced and only a limited time (72 hours) is allowed to restore the inoperable assembly(s) to OPERABLE status. If the inoperable assembly(s) cannot be restored to OPERABLE status, the associated power supply must be removed from service (Required Action A.1). This places the RPS bus in a safe condition. An alternate power supply with OPERABLE power monitoring assemblies may then be used to power the RPS bus.

The 72 hour Completion Time takes into account the remaining OPERABLE electric power monitoring assembly and the low probability of an event requiring RPS Electric Power Monitoring protection occurring during this period. It allows time for plant operations personnel to take corrective actions or to place the plant in the required condition in an orderly manner and without challenging plant systems.

Alternatively, if it is not desired to remove the power supply(s) from service (e.g., as in the case where removing the power supply(s) from service would result in a scram or isolation), Condition C or D, as applicable, must be entered and its Required Actions taken.

B.1

If both power monitoring assemblies for an inservice power supply (MG set or alternate) are inoperable, or both power monitoring assemblies in each inservice power supply are inoperable, the system protective function is lost. In this condition, 1 hour is allowed to restore one assembly to OPERABLE status for each inservice power supply. If one inoperable assembly for each inservice power supply cannot be restored to OPERABLE status, the associated power supplies must be removed from service within 1 hour

(continued)

BASES

ACTIONS

B.1 (continued)

(Required Action B.1). An alternate power supply with OPERABLE assemblies may then be used to power one RPS bus. The 1 hour Completion Time is sufficient for the plant operations personnel to take corrective actions and is acceptable because it minimizes risk while allowing time for restoration or removal from service of the electric power monitoring assemblies.

Alternately, if it is not desired to remove the power supply(s) from service (e.g., as in the case where removing the power supply(s) from service would result in a scram or isolation), Condition C or D, as applicable, must be entered and its Required Actions taken.

C.1 and C.2

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 1, 2, or 3, a plant shutdown must be performed. This places the plant in a condition where minimal equipment, powered through the inoperable RPS electric power monitoring assembly(s), is required and ensures that the safety function of the RPS (e.g., scram of control rods) is not required. The plant shutdown is accomplished by placing the plant in MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1 and D.2

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 4 or 5 with both RHR shutdown cooling suction isolation valves open, action must be immediately initiated to either restore one electric power monitoring assembly to OPERABLE status for the inservice power source supplying the required instrumentation powered from the RPS bus (Required Action D.1) or to isolate the RHR Shutdown Cooling System (Required Action D.2). Required Action D.1 is provided

(B)

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

because the RHR Shutdown Cooling System may be needed to provide core cooling. All actions must continue until the applicable Required Actions are completed.

E.1

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, the operator must immediately initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies (Required Action E.1). This Required Action results in the least reactive condition for the reactor core and ensures that the safety function of the RPS (e.g., scram of control rods) is not required.

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when an RPS electric power monitoring assembly is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the other RPS electric power monitoring assembly for the associated power supply maintains trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the assembly must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This 6 hour allowance is acceptable since it does not significantly reduce the probability that the RPS electric power monitoring assembly function will initiate when necessary.

SR 3.3.8.2.1

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.1 (continued)

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

SR 3.3.8.2.2 and SR 3.3.8.2.3

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

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

SR 3.3.8.2.4

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.4 (continued)

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

REFERENCES

1. FSAR, Section 8.3.1.1.6.

2. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

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

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1 (continued)

requirements provide larger margins to the fuel cladding integrity Safety Limit such that the potential adverse effect of early boiling transition during a LOCA is reduced. A larger flow mismatch can therefore be allowed when core flow is < 70% of rated core flow. (C)

The mismatch is measured in terms of percent of rated recirculation loop drive flow. If the flow mismatch exceeds the specified limits, the loop with the lower flow is considered not in operation. (A) (However, for the purpose of performing SR 3.4.1.2, the flow rate of both loops shall be used.) This SR is not required when both loops are not in operation since the mismatch limits are meaningless during single loop or natural circulation operation. The Surveillance must be performed within 24 hours after both loops are in operation. The 24 hour Frequency is consistent with the Frequency for jet pump OPERABILITY verification and has been shown by operating experience to be adequate to detect off normal jet pump loop flows in a timely manner.

SR 3.4.1.2

This SR ensures the combination of core flow and THERMAL POWER are within appropriate limits to prevent uncontrolled thermal-hydraulic oscillations. At low recirculation flows and high reactor power, the reactor exhibits increased susceptibility to thermal-hydraulic instability. The power-to-flow map specified in the COLR is based on guidance provided in References 6, 7, and 8. The 24 hour Frequency is based on operating experience and the operator's inherent knowledge of the reactor status, including significant changes in THERMAL POWER and core flow.

REFERENCES

1. FSAR, Sections 6.3 and 15.F.4.

2. FSAR, Section 6.3.3.7.2.

3. FSAR, Section 5.4.1.1.

4. EMF-95-007, "WNP-2 Cycle 11 Reload Analysis," March 1995.

(continued)

BASES

REFERENCES (continued)

5. EMF-95-006, "WNP-2 Cycle 11 Plant Transient Analysis," March 1995.

6. GE Service Information Letter No. 380, "BWR Core Thermal Hydraulic Stability," Revision 1, February 10, 1984.

7. NRC Generic Letter 86-02, "Technical Resolution of Generic Issue B-19, Thermal Hydraulic Stability," January 22, 1986.

8. EMF-CC-074(P)(A), "STAIF - A Computer Program for BWR Stability in the Frequency Domain (Volume 1)" and "STAIF - A Computer Program for BWR Stability in the Frequency Domain, Code Qualification Report (Volume 2)," July 1994.

9. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

BASES

LCO (continued)

b. Unidentified LEAKAGE

Five gpm of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the drywell atmosphere monitoring and drywell floor drain sump flow monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB. (B)

c. Total LEAKAGE

The total LEAKAGE limit is based on a reasonable minimum detectable amount. The limit also accounts for LEAKAGE from known sources (identified LEAKAGE). Violation of this LCO indicates an unexpected amount of LEAKAGE and, therefore, could indicate new or additional degradation in an RCPB component or system.

d. Unidentified LEAKAGE Increase

An unidentified LEAKAGE increase of > 2 gpm within the previous 24 hour period indicates a potential flaw in the RCPB and must be quickly evaluated to determine the source and extent of the LEAKAGE. The increase is measured relative to the steady state value; temporary changes in LEAKAGE rate as a result of transient conditions (e.g., startup) are not considered. As such, the 2 gpm increase limit is only applicable in MODE 1 when operating pressures and temperatures are established. Violation of this LCO could result in continued degradation of the RCPB.

APPLICABILITY

In MODES 1, 2, and 3, the RCS operational LEAKAGE LCO applies because the potential for RCPB LEAKAGE is greatest when the reactor is pressurized.

In MODES 4 and 5, RCS operational LEAKAGE limits are not required since the reactor is not pressurized and stresses in the RCPB materials and potential for LEAKAGE are reduced.

(continued)

BASES

ACTIONS

A.1 (continued)

4 hours. Required Action A.1 is modified by a Note stating that a check valve used for isolation must meet the same leakage requirements as the PIVs and must be on the RCPB. (B)

Four hours provides time to reduce leakage in excess of the allowable limit and to isolate the flow path if leakage cannot be reduced while corrective actions to reseat the leaking PIVs are taken. The 4 hours allows time for these actions, restricts the time of operation with leaking valves, and considers the low probability of a second valve failing during this time period and the low probability of a pressure boundary rupture of the low pressure ECCS piping when overpressurized to reactor pressure (Ref. 8).

B.1 and B.2

If leakage cannot be reduced or the system isolated, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. This action may reduce the leakage and also reduces the potential for a LOCA outside the containment. The Completion Times are reasonable, based on operating experience, to achieve the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

Performance of leakage testing on each RCS PIV is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit of 0.5 gpm per inch of nominal valve diameter up to 5 gpm maximum applies to each valve. Leakage testing requires a stable pressure condition. As stated in the LCO section of the Bases, the test pressure may be at a lower pressure than the maximum pressure differential (at the RCS maximum pressure of 1035 psig), provided the observed leakage rate is adjusted in accordance with Reference 4. The actual test pressure shall be $\geq$ 935 psig. For the two PIVs in series, the leakage requirement applies to each valve individually and not to the combined leakage across both valves. If the PIVs are not individually leakage tested, one valve may have (A)

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1 (continued)

failed completely and not be detected if the other valve in series meets the leakage requirement. In this situation, the protection provided by redundant valves would be lost.

The Frequency required by the Inservice Testing Program is within the ASME Code, Section XI, Frequency requirement and is based on the need to perform this Surveillance under the conditions that apply during an outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

Therefore, this SR is modified by a Note that states the leakage Surveillance is only required to be performed in MODES 1 and 2. Entry into MODE 3 is permitted for leakage testing at high differential pressures with stable conditions not possible in the lower MODES.

REFERENCES

1. 10 CFR 50.2.

2. 10 CFR 50.55a(c).

3. 10 CFR 50, Appendix A, GDC 55.

4. ASME, Boiler and Pressure Vessel Code, Section XI.

5. NUREG-0677, "The Probability of Intersystem LOCA: Impact Due to Leak Testing and Operational Changes," May 1980.

6. Licensee Controlled Specifications Manual.

7. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

8. NEDC-31339, "BWR Owners' Group Assessment of Emergency Core Cooling System Pressurization in Boiling Water Reactors," November 1986.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.8.2

This SR requires the performance of a CHANNEL FUNCTIONAL TEST of the required RCS leakage detection instrumentation. The test ensures that the monitors can perform their function in the desired manner. The test also verifies the alarm setpoint and relative accuracy of the instrument string. The Frequency of 31 days considers instrument reliability, and operating experience has shown it proper for detecting degradation.

SR 3.4.8.3

This SR requires the performance of a CHANNEL CALIBRATION of the required RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside the drywell. The Frequency of 18 months is a typical refueling cycle and considers channel reliability. Operating experience has proven this Frequency is acceptable.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 30.
2. Regulatory Guide 1.45, May 1973.
3. FSAR, Section 5.2.5.5.5.
4. GEAP-5620, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flaws," April 1968. (B)
5. NUREG-75/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactors," October 1975.
6. FSAR, Section 5.2.5.5.
7. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

BASES

ACTIONS

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

The required cooling capacity of the alternate method should be ensured by verifying (by calculation or demonstration) its capability to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as, or contributing to, the alternate method capability. Alternate methods that can be used include (but are not limited to) the Condensate and Main Steam Systems, the Reactor Water Cleanup System (by itself, or using feed and bleed in combination with the Control Rod Drive System or Condensate System) and, a combination of an ECCS pump and a safety/relief valve. 1 B

However, due to the potentially reduced reliability of the alternate methods of decay heat removal, it is also required to reduce the reactor coolant temperature to the point where MODE 4 is entered.

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

With no RHR shutdown cooling subsystem and no recirculation pump in operation, except as is permitted by LCO Note 1, reactor coolant circulation by the RHR shutdown cooling subsystem or one recirculation pump must be restored without delay.

Until RHR or recirculation pump operation is re-established, an alternate method of reactor coolant circulation must be placed into service. This will provide the necessary circulation for monitoring coolant temperature. The 1 hour Completion Time is based on the coolant circulation function and is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation. Furthermore, verification of the functioning of the alternate method must be reconfirmed every 12 hours thereafter. This will provide assurance of continued temperature monitoring capability.

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

(continued)

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 Residual Heat Removal (RHR) Shutdown Cooling System—Cold Shutdown

BASES

BACKGROUND

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed to maintain the temperature of the reactor coolant at ≤ 200°F in preparation for performing Refueling maintenance operations, or the decay heat must be removed for maintaining the reactor in the Cold Shutdown condition. (B)

The two redundant, manually controlled shutdown cooling subsystems of the RHR System provide decay heat removal. Each loop consists of a motor driven pump, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via the associated recirculation loop. The RHR heat exchangers transfer heat to the Standby Service Water (SW) System.

APPLICABLE SAFETY ANALYSES

Decay heat removal by the RHR System in the shutdown cooling mode is not required for mitigation of any event or accident evaluated in the safety analyses. Decay heat removal is, however, an important safety function that must be accomplished or core damage could result. The RHR Shutdown Cooling System meets Criterion 4 of the NRC Policy Statement (Ref. 1).

LCO

Two RHR shutdown cooling subsystems are required to be OPERABLE, and, when no recirculation pump is in operation, one RHR shutdown cooling subsystem must be in operation. An OPERABLE RHR shutdown cooling subsystem consists of one OPERABLE RHR pump, one heat exchanger, one SW pump providing cooling to the heat exchanger; and the associated piping and valves. Each shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. In MODE 4, one RHR shutdown cooling subsystem can provide the required cooling, but two subsystems are required to be OPERABLE to provide redundancy. Operation of one subsystem

(continued)

BASES (continued)

ACTIONS

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

A.1

With one of the two RHR shutdown cooling subsystems inoperable except as permitted by LCO Note 2, the remaining subsystem is capable of providing the required decay heat removal. However, the overall reliability is reduced. Therefore, an alternate method of decay heat removal must be provided. With both RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of these alternate method(s) must be reconfirmed every 24 hours thereafter. This will provide assurance of continued heat removal capability.

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

(continued)

BASES

ACTIONS

A.1 (continued)

and bleed in combination with the Control Rod Drive System or Condensate System) and a combination of an ECCS pump and a safety/relief valve.

B.1 and B.2

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

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

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

This Surveillance verifies that one RHR shutdown cooling subsystem or recirculation pump is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR subsystem in the control room.

REFERENCES

1. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

BASES

BACKGROUND (continued)

manifold subsystems will then provide a nominal pressure of 180 psig nitrogen from banks of high pressure compressed nitrogen cylinders. These cylinders provide a 30 day supply of nitrogen for the ADS function during a post LOCA condition.

APPLICABLE SAFETY ANALYSES

The ECCS performance is evaluated for the entire spectrum of break sizes for a postulated LOCA. The accidents for which ECCS operation is required are presented in References 5, 6, and 7. The required analyses and assumptions are defined in 10 CFR 50 (Ref. 8), and the results of these analyses are described in Reference 9.

This LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 10), will be met following a LOCA assuming the worst case single active component failure in the ECCS:

a. Maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from zirconium water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;

d. The core is maintained in a coolable geometry; and

e. Adequate long term cooling capability is maintained.

The limiting single failures are discussed in Reference 11. For a large break LOCA, failure of ECCS subsystems in Division 1 (LPCS and LPCI A) or Division 2 (LPCI B and LPCI C) due to failure of its associated diesel generator is, in general, the most severe failure. For a small break LOCA, HPCS System failure is the most severe failure. The small break analysis also assumes two ADS valves are inoperable at the time of the accident. The remaining OPERABLE ECCS subsystems provide the capability to adequately cool the core and prevent excessive fuel damage. (13)

The ECCS satisfy Criterion 3 of the NRC Policy Statement (Ref. 12).

(continued)

BASES (continued)

LCO

Each ECCS injection/spray subsystem and six ADS valves are required to be OPERABLE. The ECCS injection/spray subsystems are defined as the three LPCI subsystems, the LPCS System, and the HPCS System. The low pressure ECCS injection/spray subsystems are defined as the LPCS System and the three LPCI subsystems. (B)

With less than the required number of ECCS subsystems OPERABLE during a limiting design basis LOCA concurrent with the worst case single failure, the limits specified in 10 CFR 50.46 (Ref. 10) could potentially be exceeded. All ECCS subsystems must therefore be OPERABLE to satisfy the single failure criterion required by 10 CFR 50.46 (Ref. 10).

LPCI subsystems may be considered OPERABLE during alignment and operation for decay heat removal when below the actual RHR cut in permissive pressure in MODE 3, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. Alignment and operation for decay heat removal includes when the required RHR pump is not operating or when the system is being realigned from or to the RHR shutdown cooling mode. At these low pressures and decay heat levels, a reduced complement of ECCS subsystems should provide the required core cooling, thereby allowing operation of RHR shutdown cooling when necessary.

APPLICABILITY

All ECCS subsystems are required to be OPERABLE during MODES 1, 2, and 3 when there is considerable energy in the reactor core and core cooling would be required to prevent fuel damage in the event of a break in the primary system piping. In MODES 2 and 3, the ADS function is not required when pressure is $\leq$ 150 psig because the low pressure ECCS subsystems (LPCS and LPCI) are capable of providing flow into the RPV below this pressure. ECCS requirements for MODES 4 and 5 are specified in LCO 3.5.2, "ECCS – Shutdown."

ACTIONS

A.1

If any one low pressure ECCS injection/spray subsystem is inoperable, the inoperable subsystem must be restored to OPERABLE status within 14 days. In this condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced because a single failure in one of the remaining OPERABLE subsystems concurrent with a LOCA may result in the ECCS not

(continued)

BASES

ACTIONS

C.1 (continued)

during a LOCA. However, overall ECCS reliability is reduced in this Condition because a single failure in one of the remaining OPERABLE subsystems concurrent with a design basis LOCA may result in the ECCS not being able to perform its intended safety function. Since the ECCS availability is reduced relative to Condition A, a more restrictive Completion Time is imposed. The 7 days Completion Time is based on a reliability study, as provided in Reference 13.

D.1 and D.2

If any Required Action and associated Completion Time of Condition A, B, or C are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

The LCO requires six ADS valves to be OPERABLE to provide the ADS function. Reference 15 contains the results of an analysis that evaluated the effect of two ADS valves being out of service. This analysis showed that assuming a failure of the HPCS System, operation of only five ADS valves will provide the required depressurization. However, overall reliability of the ADS is reduced because a single failure in the OPERABLE ADS valves could result in a reduction in depressurization capability. Therefore, operation is only allowed for a limited time. The 14 day Completion Time is based on a reliability study (Ref. 14) and has been found to be acceptable through operating experience. (B)

F.1 and F.2

If any one low pressure ECCS injection/spray subsystem is inoperable in addition to one required ADS valve inoperable, adequate core cooling is ensured by the OPERABILITY of HPCS

(continued)

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

B 3.5.2 ECCS – Shutdown

BASES

BACKGROUND	A description of the High Pressure Core Spray (HPCS) System, Low Pressure Core Spray (LPCS) System, and low pressure coolant injection (LPCI) mode of the Residual Heat Removal (RHR) System is provided in the Bases for LCO 3.5.1, "ECCS – Operating."
APPLICABLE SAFETY ANALYSES	ECCS performance is evaluated for the entire spectrum of break sizes for a postulated loss of coolant accident (LOCA). The long term cooling analysis following a design basis LOCA (Ref. 1) demonstrates that only one ECCS injection/spray subsystem is required, post LOCA, to maintain adequate reactor vessel water level in the event of an inadvertent vessel draindown. It is reasonable to assume, based on engineering judgement, that while in MODES 4 and 5, one ECCS injection/spray subsystem can maintain adequate reactor vessel water level. To provide redundancy, a minimum of two ECCS injection/spray subsystems are required to be OPERABLE in MODES 4 and 5. (B) (B) The ECCS satisfy Criterion 3 of the NRC Policy Statement (Ref. 2).
LCO	Two ECCS injection/spray subsystems are required to be OPERABLE. The ECCS injection/spray subsystems are defined as the three LPCI subsystems, the LPCS System, and the HPCS System. The LPCS System and each LPCI subsystem consist of one motor driven pump, piping, and valves to transfer water from the suppression pool to the RPV. The HPCS System consists of one motor driven pump, piping, and valves to transfer water from the suppression pool or condensate storage tank (CST) to the RPV. The necessary portions of the Standby Service Water and HPCS Service Water Systems, as applicable, are also required to provide appropriate cooling to each required ECCS injection/spray subsystem. One LPCI subsystem (A or B) may be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.1 Primary Containment

BASES

BACKGROUND

The function of the primary containment is to isolate and contain fission products released from the Reactor Primary System following a Design Basis Accident (DBA) and to confine the postulated release of radioactive material to within limits. The primary containment consists of a free-standing steel pressure vessel, which surrounds the Reactor Primary System and provides an essentially leak tight barrier against an uncontrolled release of radioactive material to the environment. Additionally, this structure is enclosed in a reinforced concrete vessel, which provides shielding from the fission products that may be present in the primary containment atmosphere following accident conditions.

The isolation devices for the penetrations in the primary containment boundary are a part of the primary containment leak tight barrier. To maintain this leak tight barrier:

a. All penetrations required to be closed during accident conditions are either:

   1. capable of being closed by an OPERABLE automatic containment isolation system, or

   2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)";

b. Primary containment air locks are OPERABLE, except as provided in LCO 3.6.1.2, "Primary Containment Air Locks"; and

c. All equipment hatches are closed.

This Specification ensures that the performance of the primary containment, in the event of a DBA, meets the assumptions used in the safety analyses of References 1 and 2. SR 3.6.1.1.1 leakage rate requirements are in conformance with 10 CFR 50, Appendix J, Option B (Ref. 3), as modified by approved exemptions. (B)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The safety design basis for the primary containment is that it must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBA that postulates the maximum release of radioactive material within primary containment is a double-ended recirculation suction line break LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE such that release of fission products to the environment is controlled by the rate of primary containment leakage.

Analytical methods and assumptions involving the primary containment are presented in References 1 and 2. The safety analyses assume a nonmechanistic fission product release following a DBA, which forms the basis for determination of offsite doses. The fission product release is, in turn, based on an assumed leakage rate from the primary containment. OPERABILITY of the primary containment ensures that the leakage rate assumed in the safety analyses is not exceeded.

The maximum allowable leakage rate for the primary containment (L_a) is 0.5% by weight of the containment air per 24 hours at the design basis LOCA maximum peak containment pressure (P_a) of 38 psig (Ref. 4). (A)

Primary containment satisfies Criterion 3 of the NRC Policy Statement (Ref. 5).

LCO

Primary containment OPERABILITY is maintained by limiting leakage to $\leq 1.0\ L_a$, except prior to the first startup after performing a required Primary Containment Leakage Rate Testing Program leakage test. At this time, applicable leakage limits must be met. In addition, the leakage from the drywell to the suppression chamber must be limited to ensure the pressure suppression function is accomplished and the suppression chamber pressure does not exceed design limits. Compliance with this LCO will ensure a primary containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis. Individual leakage rates specified for the primary containment air locks are addressed in LCO 3.6.1.2. (B)

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, primary containment is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

ACTIONS

A.1

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

B.1 and B.2

If primary containment cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1

Maintaining the primary containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Primary Containment Leakage Rate Testing Program. Failure to meet air lock leakage (SR 3.6.1.2.1), secondary containment bypass leakage (SR 3.6.1.3.10), or main steam isolation valve leakage (SR 3.6.1.3.10) limit does not necessarily result in a failure of this SR. The impact of the failure to meet these

(B)

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1 (continued)

SRs must be evaluated against the Type A, B, and C acceptance criteria of the Primary Containment Leakage Rate Testing Program. (B)

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

SR 3.6.1.1.2

Maintaining the pressure suppression function of primary containment requires limiting the leakage from the drywell to the suppression chamber. Thus, if an event were to occur that pressurized the drywell, the steam would be directed through the downcomers into the suppression pool. This SR measures drywell to suppression chamber differential pressure during a 4 hour period to ensure that the leakage paths that would bypass the suppression pool are within allowable limits.

Satisfactory performance of this SR can be achieved by establishing a known differential pressure (≥ 1.5 psid) between the drywell and the suppression chamber and verifying that the bypass leakage is equivalent to that through an area $\leq 0.005\ ft^2$. The leakage test is performed every 24 months. The 24 month Frequency was developed considering it is prudent that this Surveillance be performed during a unit outage and also in view of the fact that component failures that might have affected this test are identified by other primary containment SRs. Two consecutive test failures, however, would indicate unexpected primary containment degradation; in this event, as the Note indicates, increasing the Frequency to once every 12 months is required until the situation is remedied as evidenced by passing two consecutive tests.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Section 6.2.1.1.3.5.

2. FSAR, Section 15.F.6.

3. 10 CFR 50, Appendix J, Option B. (B)

4. FSAR, Section 6.2.6.1.

5. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132). (B)

BASES

ACTIONS

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

conservative to immediately declare the primary containment inoperable if both doors in the air lock have failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed) primary containment remains OPERABLE, yet only 1 hour (according to LCO 3.6.1.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

Required Action C.2 requires that one door in the primary containment air lock must be verified closed. This Required Action must be completed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1.1, which require that primary containment be restored to OPERABLE status within 1 hour.

Additionally, the air lock must be restored to OPERABLE status within 24 hours (Required Action C.3). The 24 hour Completion Time is reasonable for restoring the inoperable air lock to OPERABLE status considering that at least one door is maintained closed in the air lock.

D.1 and D.2

If the inoperable primary containment air lock cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1

Maintaining the primary containment air lock OPERABLE requires compliance with the leakage rate test requirements of the Primary Containment Leakage Rate Testing Program. This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The

(B)

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1 (continued)

acceptance criteria were established as a small fraction of the total allowable primary containment leakage. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall primary containment leakage rate. The Frequency is required by the Primary Containment Leakage Rate Testing Program. (6)

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR, requiring the results to be evaluated against the acceptance criteria of SR 3.6.1.1.1 (the Primary Containment Leakage Rate Testing Program). This ensures that air lock leakage is properly accounted for in determining the combined Type B and C primary containment leakage. (6)

SR 3.6.1.2.2

The air lock interlock mechanism is designed to prevent simultaneous opening of both doors in the air lock. Since both the inner and outer doors of the air lock are designed to withstand the maximum expected post accident primary containment pressure (Ref. 6), closure of either door will support primary containment OPERABILITY. Thus, the interlock feature supports primary containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous inner and outer door opening will not inadvertently occur. Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is not normally challenged when the primary containment air lock door is used for entry and exit (procedures require strict adherence to single door opening), this test is only required to be performed every 24 months. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage, and the potential for loss of primary containment OPERABILITY if the Surveillance were performed with the reactor at power. Operating experience has shown

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.2 (continued)

these components usually pass the Surveillance when performed at the 24 month Frequency. The 24 month Frequency is based on engineering judgment and is considered adequate given that the interlock is not challenged during use of the air lock.

REFERENCES

1. FSAR, Section 3.8.2.1.1.4.

2. FSAR, Section 3.8.2.7.5.

3. FSAR, Section 6.2.6.1.

4. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

5. 10 CFR 50, Appendix J, Option B. (B)

6. FSAR, Section 3.8.2.7.3.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The single failure criterion required to be imposed in the conduct of unit safety analyses was considered in the original design of the primary containment purge valves. Two valves in series on each purge line provide assurance that both the supply and exhaust lines could be isolated even if a single failure occurred.

PCIVs satisfy Criterion 3 of the NRC Policy Statement (Ref. 3).

LCO

PCIVs form a part of the primary containment boundary. The PCIV safety function is related to minimizing the loss of reactor coolant inventory and establishing the primary containment boundary during a DBA.

The power operated, automatic isolation valves are required to have isolation times within limits and actuate on an automatic isolation signal. While the reactor building-to-suppression chamber vacuum breakers isolate primary containment penetrations, they are excluded from this Specification. Controls on their isolation function are adequately addressed in LCO 3.6.1.6, "Reactor Building-to-Suppression Chamber Vacuum Breakers." The valves covered by this LCO are listed with their associated stroke times in Reference 4.

The normally closed PCIVs are considered OPERABLE when manual valves are closed or open in accordance with appropriate administrative controls, automatic valves are de-activated and secured in their closed position, blind flanges are in place, and closed systems are intact. These passive isolation valves and devices are those listed in Reference 4. MSIV and hydrostatically tested valve leakage are exempt from Type C testing limits and must meet specific leakage rate requirements, and secondary containment bypass valves must meet additional leakage rate requirements. Other PCIV leakage rates are addressed by LCO 3.6.1.1, "Primary Containment," as Type B or C testing. I 6

This LCO provides assurance that the PCIVs will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the primary containment boundary during accidents.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.10

This SR ensures that the leakage rate of secondary containment bypass leakage paths is less than the specified leakage rate. This provides assurance that the assumptions in the radiological evaluations that form the basis of the FSAR (Ref. 1) are met. The leakage rate of each bypass leakage path is assumed to be the maximum pathway leakage (leakage through the worse of the two isolation valves) unless the penetration is isolated by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. In this case, the leakage rate of the isolated bypass leakage path is assumed to be the actual pathway leakage through the isolation device. If both isolation valves in the penetration are closed, the actual leakage rate is the lesser leakage rate of the two valves. The Frequency is required by the Primary Containment Leakage Rate Testing Program. This SR simply imposes additional acceptance criteria. (B)

SR 3.6.1.3.11

The analyses in Reference 1 are based on leakage that is less than the specified leakage rate. Leakage through each MSIV must be $\leq$ 11.5 scfh when tested at P_t (25 psig). This ensures that MSIV leakage is properly accounted for in determining the overall primary containment leakage rate. The Frequency is required by the Primary Containment Leakage Rate Testing Program. (B) (B)

SR 3.6.1.3.12

Surveillance of hydrostatically tested lines provides assurance that the calculation assumptions of Reference 1 are met. The acceptance criteria for the combined leakage of all hydrostatically tested lines is $\leq$ 1.0 gpm times the total number of hydrostatically tested PCIVs when tested at 1.1 P_a (41.8 psig). The combined leakage rates must be tested at the Frequency required by the Primary Containment Leakage Rate Testing Program. (B) (B)

(continued)

BASES (continued)

REFERENCES

1. FSAR, Chapter 6.2.

2. FSAR, Section 15.F.2.2.1.

3. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

4. Licensee Controlled Specifications Manual.

(B)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.5 Residual Heat Removal (RHR) Drywell Spray

BASES

BACKGROUND

The primary containment is designed with a suppression pool so that, in the event of a loss of coolant accident (LOCA), steam released from the primary system is channeled through the suppression pool water and condensed without producing significant pressurization of the primary containment. The primary containment is designed so that with the pool initially at the minimum water volume and the worst single failure of the primary containment heat removal systems, suppression pool energy absorption combined with subsequent operator controlled pool cooling will prevent the primary containment pressure from exceeding its design value. However, the primary containment must also withstand a postulated bypass leakage pathway that allows the passage of steam from the drywell directly into the suppression pool airspace, bypassing the suppression pool. The RHR Drywell Spray System is designed to mitigate the effects of bypass leakage.

There are two redundant, 100% capacity RHR drywell spray subsystems. Each subsystem consists of a suction line from the suppression pool, an RHR pump, and one spray sparger inside the drywell. Dispersion of the spray water is accomplished by spray nozzles in each subsystem. 13

The RHR drywell spray mode will be manually initiated, if required, following a LOCA, according to emergency procedures.

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses that predict the primary containment pressure response for a LOCA with the maximum allowable bypass leakage area.

The equivalent flow path area for bypass leakage has been specified to be 0.05 ft^2. The analysis demonstrates that with drywell spray operation the primary containment pressure remains within design limits.

The RHR drywell spray satisfies Criterion 3 of the NRC Policy Statement (Ref. 2).

(continued)

BASES (continued)

LCO

In the event of a Design Basis Accident (DBA), a minimum of one RHR drywell spray subsystem is required to mitigate the effects of potential bypass leakage paths and maintain the primary containment peak pressure below design limits. To ensure that these requirements are met, two RHR drywell spray subsystems must be OPERABLE. Therefore, in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active failure. An RHR drywell spray subsystem is OPERABLE when the pump and associated piping, valves, instrumentation, and controls are OPERABLE. (B)

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause pressurization of primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining RHR drywell spray subsystems OPERABLE is not required in MODE 4 or 5.

ACTIONS

A.1

With one RHR drywell spray subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE RHR drywell spray subsystem is adequate to perform the primary containment bypass leakage mitigation function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced primary containment bypass leakage mitigation capability. The 7 day Completion Time was chosen in light of the redundant RHR drywell spray capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

B.1

With two RHR drywell spray subsystems inoperable, one subsystem must be restored to OPERABLE status within 8 hours. In this condition, there is a substantial loss of the primary containment bypass leakage mitigation function. The 8 hour Completion Time is based on this loss of function and is considered acceptable due to the low probability of a DBA and because alternative methods to reduce primary containment pressure are available.

(continued)

BASES (continued)

LCO

Only 7 of the 9 vacuum breakers must be OPERABLE for opening. All suppression chamber-to-drywell vacuum breakers, however, are required to be closed (except when the vacuum breakers are performing their intended design function). A vacuum breaker is OPERABLE for opening and closed when both disks in the vacuum breaker are OPERABLE for opening and closed. The vacuum breaker OPERABILITY requirement provides assurance that the drywell-to-suppression chamber negative differential pressure remains below the design value. The requirement that the vacuum breakers be closed ensures that there is no excessive bypass leakage should a LOCA occur.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could result in excessive negative differential pressure across the drywell wall, caused by the rapid depressurization of the drywell. The event that results in the limiting rapid depressurization of the drywell is the primary system rupture that purges the drywell of air and fills the drywell free airspace with steam. Subsequent condensation of the steam would result in depressurization of the drywell. The limiting pressure and temperature of the primary system prior to a DBA occur in MODES 1, 2, and 3. Excessive negative pressure inside the drywell could also occur due to inadvertent actuation of the Drywell Spray System.

In MODES 4 and 5, the probability and consequences of these events are reduced by the pressure and temperature limitations in these MODES; therefore, maintaining suppression chamber-to-drywell vacuum breakers OPERABLE is not required in MODE 4 or 5.

ACTIONS

A.1

With one of the required vacuum breakers inoperable for opening (e.g., a vacuum breaker disk is not open and may be stuck closed or not within its opening setpoint limit, so that it would not function as designed during an event that depressurized the drywell), the remaining six OPERABLE vacuum breakers are capable of providing the vacuum relief function. However, overall system reliability is reduced because a single failure in one of the remaining vacuum breakers could result in an excessive suppression chamber-to-drywell differential pressure during a DBA. Therefore, with one of the seven required vacuum breakers inoperable,

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.2 Primary Containment Atmosphere Mixing System

BASES

BACKGROUND

The Primary Containment Atmosphere Mixing System ensures a uniformly mixed post accident primary containment atmosphere, thereby minimizing the potential for local hydrogen burns due to a pocket of hydrogen above the flammable concentration.

The Primary Containment Atmosphere Mixing System is designed to withstand a loss of coolant accident (LOCA) in post accident environments without loss of function. The system has two independent subsystems consisting of head area return fans, motors, controls, and ducting. Each subsystem is sized to circulate 5000 scfm. The Primary Containment Atmosphere Mixing System employs forced circulation to ensure the proper mixing of hydrogen and oxygen in primary containment. The two subsystems are automatically initiated upon reactor scram signal. However, for the purposes of this LCO, the subsystems are only required to be initiated manually since flammability limits would not be reached until several days after a LOCA. Each subsystem is powered from a separate emergency power supply. Since each subsystem can provide 100% of the mixing requirements, the system will provide its design function with a worst case single active failure.

APPLICABLE SAFETY ANALYSES

The Primary Containment Atmosphere Mixing System provides the capability for reducing the local hydrogen and oxygen concentrations to approximately the bulk average concentrations following a Design Basis Accident (DBA). The limiting DBA relative to hydrogen and oxygen generation is a LOCA.

Oxygen may accumulate in the primary containment following a LOCA as a result of radiolytic decomposition of water in the Reactor Coolant System.

Hydrogen may accumulate in primary containment following a LOCA as a result of:

a. A metal steam reaction between the zirconium fuel rod cladding and the reactor coolant;

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

b. Radiolytic decomposition of water in the Reactor Coolant System; or

c. A reaction between the reactor coolant and the zinc rich paints used in the primary containment. However, since WNP-2 is an oxygen control plant, this form of hydrogen generation is not assumed (minimizing hydrogen production is conservative in calculating peak oxygen concentration).

To evaluate the potential for hydrogen and oxygen accumulation in primary containment following a LOCA, the hydrogen and oxygen generation as a function of time following the initiation of the accident is calculated. Conservative assumptions recommended by Reference 1 are used to maximize the amount of oxygen calculated.

The calculation confirms that one head area return fan started in accordance with plant procedures will ensure adequate mixing of hydrogen and oxygen within the primary containment atmosphere (Refs. 2 and 3). 1B

The Primary Containment Atmosphere Mixing System satisfies Criterion 3 of the NRC Policy Statement. 1B

LCO

Two head area return fans must be OPERABLE to ensure operation of at least one fan in the event of a worst case single active failure. Operation with at least one fan provides the capability of controlling the bulk hydrogen and oxygen concentrations in primary containment without exceeding the flammability limits.

APPLICABILITY

In MODES 1 and 2, the two head area return fans ensure the capability to prevent localized hydrogen and oxygen concentrations above the flammability limits of 4.0 v/o and 5.0 v/o, respectively, in the primary containment, assuming a worst case single active failure.

In MODE 3, both the hydrogen and oxygen production rates and the total hydrogen and oxygen produced after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in this MODE, the probability of an accident requiring the Containment Atmosphere Mixing System is low. Therefore, the Primary Containment Atmosphere Mixing System is not required in MODE 3. 1B

(continued)

BASES

APPLICABILITY (continued)

In MODES 4 and 5, the probability and consequences of a LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, the Primary Containment Atmosphere Mixing System is not required in these MODES.

ACTIONS

A.1

With one head area return fan inoperable, the inoperable fan must be restored to OPERABLE status within 30 days. In this condition, the remaining OPERABLE fan is adequate to perform the hydrogen and oxygen mixing function. However, the overall reliability is reduced because a single failure in the OPERABLE fan could result in reduced hydrogen and oxygen mixing capability. The 30 day Completion Time is based on the availability of the second fan, the low probability of the occurrence of a LOCA that would generate hydrogen and oxygen in amounts capable of exceeding the flammability limits, the amount of time available after the event for operator action to prevent exceeding these limits, and the availability of the Residual Heat Removal (RHR) Drywell Spray System.

Required Action A.1 has been modified by a Note indicating that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one head area return fan is inoperable. This allowance is provided because of the low probability of the occurrence of a LOCA that would generate hydrogen and oxygen in amounts capable of exceeding the flammability limits, the low probability of the failure of the OPERABLE fan, and the amount of time available after a postulated LOCA for operator action to prevent exceeding the flammability limits.

B.1 and B.2

With two head area return fans inoperable, the ability to perform the hydrogen and oxygen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen and oxygen control capability is provided by one RHR Drywell Spray subsystem. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen and oxygen control function does not exist. The verification may be performed as an administrative check by examining logs or

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

other information to determine the availability of the alternate hydrogen and oxygen control system. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen and oxygen control system. If the ability to perform the hydrogen and oxygen control function is maintained, continued operation is permitted with two head area return fans inoperable for up to 7 days. Seven days is a reasonable time to allow two head area return fans to be inoperable because the hydrogen and oxygen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen and oxygen in amounts capable of exceeding the flammability limits.

C.1

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.2.1

Operating each head area return fan for ≥ 15 minutes ensures that each subsystem is OPERABLE and that all associated controls are functioning properly. It also ensures that blockage or fan or motor failure can be detected for corrective action. The 92 day Frequency is consistent with the Inservice Testing Program Frequencies, operating experience, the known reliability of the fan motors and controls, and the two redundant fans available.

REFERENCES

1. Regulatory Guide 1.7, Revision 1, September 1976.

2. FSAR, Section 6.2.5.2.1.

3. WNP-2 Technical Memo TM-2065, "Requirements for Containment Mixing Fans," Revision 0, July 15, 1994.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

the 1280 kW standby service water pump, and for DG-3 the 2380 kW HPCS pump. This Surveillance may be accomplished by:

a. Tripping the DG output breaker with the DG carrying greater than or equal to its associated single largest post accident load while paralleled to offsite power, or while solely supplying the bus; or

b. Tripping its associated single largest post accident load with the DG solely supplying the bus.

Consistent with Regulatory Guide 1.9 (Ref. 13), the load rejection test is acceptable if the diesel speed does not exceed the nominal synchronous speed plus 75% of the difference between nominal speed and the overspeed trip setpoint, or 115% of nominal speed, whichever is lower. For all the DGs, this corresponds to 66.75 Hz, which is the nominal speed plus 75% of the difference between nominal speed and the overspeed trip setpoint.

The 24 month Frequency takes into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by two Notes. The reason for Note 1 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, Note 2 requires that, if synchronized to offsite power, testing must be performed within the power factor limit. The power factor limit is ≤ 0.92 for DG-1, ≤ 0.86 for DG-2, and ≤ 0.92 for DG-3. These power factors are chosen to be representative of the actual design basis inductive loading that the DGs could experience. To meet these power factor limits, the DGs must be loaded to the following reactive values when the SR is performed; 580 kVAR for DG-1, 760 kVAR for DG-2, and 1015 kVAR for DG-3. However, if the offsite electrical power distribution system voltage is high, increased excitation will be necessary for the DG to match system

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

voltage when synchronizing to the associated ESF bus. Once tied to the ESF bus, it may not be possible to increase DG excitation sufficiently to meet the required reactive load value that ensures the power factor limit is met, without exceeding the DG excitation system ratings. Therefore, to ensure the DG is not placed in an unsafe condition during this test, the power factor limit does not have to be met if grid voltage does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the power factor should be maintained as close to the limit as practicable.

SR 3.8.1.10

Consistent with Regulatory Guide 1.9 (Ref. 13), paragraph C.2.2.8, this Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide DG damage protection. While the DG is not expected to experience this transient during an event, and continues to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing must be performed within the power factor limit. The power factor limit is ≤ 0.89 for DG-1, ≤ 0.88 for DG-2, and ≤ 0.91 for DG-3. These power factors are chosen to be representative of the actual design basis inductive loading that the DGs could experience. To meet these power factor limits, the DGs must be loaded to the following reactive values when the SR is performed; 2165 kVAR for DG-1, 2085 kVAR for DG-2, and 1150 kVAR for DG-3.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

The 24 month Frequency takes into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by two Notes. The reason for Note 1 is that during operation with the reactor critical, performance of this SR could cause perturbation to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Note 2 is provided in recognition that if the offsite electrical power distribution system voltage is high, increased excitation will be necessary for the DG to match system voltage when synchronizing to the associated ESF bus. Once tied to the ESF bus, it may not be possible to increase DG excitation sufficiently to meet the required reactive load value that ensures the power factor limit is met, without exceeding the DG excitation system ratings. Therefore, to ensure the DG is not placed in an unsafe condition during this test, the power factor limit does not have to be met if grid voltage does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the power factor should be maintained as close to the limit as practicable. (B)

SR 3.8.1.11

Consistent with Regulatory Guide 1.9 (Ref. 13), paragraph C.2.2.4, this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

The DG auto-start and energization of permanently connected loads times of 15 seconds for Division 1 and 2 and 18 seconds for Division 3 are derived from requirements of the accident analysis for responding to a design basis large break LOCA (Ref. 17). The DG-3 18 second start time includes the Loss of Voltage—Time Delay Function specified

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

in LCO 3.3.8.1. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved.

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

The Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.12

Consistent with Regulatory Guide 1.9 (Ref. 13), paragraph C.2.2.5, this Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (15 seconds) from the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability. SR 3.8.1.12.d and SR 3.8.1.12.e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on an ECCS signal without loss of offsite power.

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

The Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with the expected fuel cycle lengths.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.13

Consistent with Regulatory Guide 1.9 (Ref. 13), paragraph C.2.2.12, this Surveillance demonstrates that DG non-critical protective functions (e.g., high jacket water temperature) are bypassed on a loss of voltage signal concurrent with an ECCS initiation test signal and critical protective functions (engine overspeed, generator differential current, and incomplete starting sequence) trip the DG to avert substantial damage to the DG unit. The non-critical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The 24 month Frequency is based on engineering judgment, taking into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

The SR is modified by a Note. The reason for the Note is that performing the Surveillance removes a required DG from service. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.14

Consistent with Regulatory Guide 1.9 (Ref. 13), paragraph C.2.2.9, this Surveillance requires demonstration that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours, 22 hours of which is at a load equivalent to 90% to 100% of the continuous rating of the DG and 2 hours of which is at a load equivalent to 105% to 110% of the continuous duty rating of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelube and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed within the power factor (R)

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

limit. The power factor limit is ≤ 0.89 for DG-1, ≤ 0.88 for DG-2, and ≤ 0.91 for DG-3. These power factors are chosen to be representative of the actual design basis inductive loading that the DGs could experience. To meet these power factor limits, the DGs must be loaded to the following reactive values when the SR is performed; 2165 kVAR for DG-1, 2085 kVAR for DG-2, and 1150 kVAR for DG-3. (B)

The 24 month Frequency takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by three Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. 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. Similarly, momentary power factor transients above the limit do not invalidate the test. The reason for Note 2 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that would challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Note 3 is provided in recognition that if the offsite electrical power distribution system voltage is high, increased excitation will be necessary for the DG to match system voltage when synchronizing to the associated ESF bus. Once tied to the ESF bus, it may not be possible to increase DG excitation sufficiently to meet the required reactive load value that ensures the power factor limit is met, without exceeding the DG excitation system ratings. Therefore, to ensure the DG is not placed in an unsafe condition during this test, the power factor limit does not have to be met if grid voltage does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the power factor should be maintained as close to the limit as practicable. (B)

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

limit. The power factor limit is ≤ 0.89 for DG-1, ≤ 0.88 for DG-2, and ≤ 0.91 for DG-3. These power factors are chosen to be representative of the actual design basis inductive loading that the DGs could experience. To meet these power factor limits, the DGs must be loaded to the following reactive values when the SR is performed; 2170 kVAR for DG-1, 2100 kVAR for DG-2, and 1140 kVAR for DG-3. (B)

The 24 month Frequency takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by three Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. 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. Similarly, momentary power factor transients above the limit do not invalidate the test. The reason for Note 2 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that would challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Note 3 is provided in recognition that if the offsite electrical power distribution system voltage is high, increased excitation will be necessary for the DG to match system voltage when synchronizing to the associated ESF bus. Once tied to the ESF bus, it may not be possible to increase DG excitation sufficiently to meet the required reactive load value that ensures the power factor limit is met, without exceeding the DG excitation system ratings. Therefore, to ensure the DG is not placed in an unsafe condition during this test, the power factor limit does not have to be met if grid voltage does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the power factor should be maintained as close to the limit as practicable. (B)

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 15 seconds. The 15 second time is derived from the requirements of the accident analysis for responding to a design basis large break LOCA (Ref. 17).

The 24 month Frequency takes into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The requirement that the diesel has operated for at least 1 hour at full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing.

SR 3.8.1.16

Consistent with Regulatory Guide 1.9 (Ref. 13), paragraph C.2.2.11, this Surveillance ensures that the manual synchronization and automatic load transfer from the DG to the offsite source can be made and that the DG can be returned to ready-to-load status when offsite power is restored. It also ensures that the auto-start logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready-to-load status when the DG is at rated speed and voltage, the output breaker is open and can receive an auto-close signal on bus undervoltage, and the individual load timers are reset.

The Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycles.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.16 (continued)

distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.17

Consistent with Regulatory Guide 1.9 (Ref. 13), paragraph C.2.2.13, demonstration of the parallel test mode override ensures that the DG availability under accident conditions is not compromised as the result of testing. Interlocks to the LOCA sensing circuits cause the DG to automatically reset to ready-to-load operation if an ECCS initiation signal is received during operation in the test mode. Ready-to-load operation is defined as the DG running at rated speed and voltage with the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. 19), paragraph 6.2.6(2).

The requirement to automatically energize the emergency loads with offsite power is essentially identical to that of SR 3.8.1.12. The intent in the requirement associated with SR 3.8.1.17.b is to show that the emergency loading is not affected by the DG operation in test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The 24 month Frequency takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.18

Under accident conditions, loads are sequentially connected to the bus by the automatic load sequence time delay relays. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor starting currents. The 10% load sequence time interval tolerance ensures that a sufficient time interval exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 2 provides a summary of the automatic loading of ESF buses. Since only DG-1 and DG-2 have more than one load block, this SR is only applicable to these DGs.

The Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance during these MODES would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.19

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates the DG operation, as discussed in the Bases for SR 3.8.1.11, during a loss of offsite power actuation test signal in conjunction with an ECCS initiation signal. Since the DG-3 Loss of Voltage—Time Delay Function is bypassed during an ECCS initiation signal, a 15 second DG-3 start time applies, consistent with the DBA LOCA analysis (Ref. 17). In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.19 (continued)

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

The Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with an expected fuel cycle length.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.20

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously.

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 13), paragraph C.2.2.14.

This SR is modified by a Note. The reason for the Note is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.

2. FSAR, Chapter 8.

(continued)

BASES

REFERENCES (continued)

3. FSAR, Figure 8.3-23.

4. FSAR, Tables 8.3-1, 8.3-2, and 8.3-3.

5. Safety Guide 9, Revision 0, March 1971.

6. FSAR, Chapter 6.

7. FSAR, Chapters 15 and 15.F.

8. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

9. Regulatory Guide 1.93, Revision 0, December 1974.

10. Generic Letter 84-15, July 2, 1984.

11. GE-NE-A00-05809-01, "Technical Specifications Improvements to the WNP-2 Emergency Core Cooling System for Perform Phase III Risk Method Application," September 1994.

12. 10 CFR 50, Appendix A, GDC 18.

13. Regulatory Guide 1.9, July 1993.

14. Regulatory Guide 1.108, Revision 1, August 1977.

15. Regulatory Guide 1.137, Revision 1, October 1979.

16. Supply System Calculations Nos. E/I-02-87-07 and E/I-02-90-01.

17. FSAR, Section 15.F.6.

18. ASME, Boiler and Pressure Vessel Code, Section XI.

19. IEEE Standard 308-1974.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1 (continued)

are consistent with the initial voltages assumed in the battery sizing calculations. The 7 day Frequency is conservative when compared with the manufacturers recommendations and IEEE-450 (Ref. 11).

SR 3.8.4.2

Visual inspection to detect corrosion of the battery cells and connections, or measurement of the resistance of each inter-cell, inter-rack, and inter-tier connection, provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

For inter-cell connectors, the limits are $\leq$ 24.4 E-6 ohms for the Division 1 and 2 batteries and $\leq$ 169 E-6 ohms for the Division 3 battery. For inter-tier and inter-rack connectors, the limits are $\leq$ 20% above the resistance as measured during installation.

The Surveillance Frequency for these inspections, which can detect conditions that can cause power losses due to resistance heating, is 92 days. This Frequency is considered acceptable based on operating experience related to detecting corrosion trends.

SR 3.8.4.3

Visual inspection of the battery cells, cell plates, and battery racks provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance. The presence of physical damage or deterioration does not necessarily represent a failure of this SR, provided an evaluation determines that the physical damage or deterioration does not affect the OPERABILITY of the battery (its ability to perform its design function).

The 12 month Frequency of this SR is consistent with IEEE-450 (Ref. 11), which recommends detailed visual inspection of cell condition on a yearly basis.

(B)

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.4 and SR 3.8.4.5

Visual inspection and resistance measurements of inter-cell, inter-rack, and inter-tier connections provides an indication of physical damage or abnormal deterioration that could indicate degraded battery condition. The anti-corrosion material is used to ensure good electrical connections and to reduce terminal deterioration. The visual inspection for corrosion is not intended to require removal of and inspection under each terminal connection.

The removal of visible corrosion is a preventive maintenance SR. The presence of visible corrosion does not necessarily represent a failure of this SR, provided visible corrosion is removed during performance of this Surveillance.

For inter-cell connectors, the limits are $\leq$ 24.4 E-6 ohms for the Division 1 and 2 batteries and $\leq$ 169 E-6 ohms for the Division 3 battery. For inter-tier and inter-rack connectors, the limits are $\leq$ 20% above the resistance as measured during installation.

The 12 month Frequency of these SRs is consistent with IEEE-450 (Ref. 11), which recommends detailed visual inspection of cell condition and inspection of cell to cell and terminal connection resistance on a yearly basis. (B)

SR 3.8.4.6

Battery charger capability requirements are based on the design capacity of the chargers (Ref. 4). According to Regulatory Guide 1.32 (Ref. 12), the battery charger supply is required to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensure that these requirements can be satisfied. The charger shall be loaded, to a minimum, at three separate and sequential load ratings, 50%, 75%, and 100%, for $\geq$ 30 minutes at each load rating.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.8 (continued)

factor of 120%. A capacity of 80% for the 125 V battery and 83.4% for the 250 V battery shows that the battery is getting old and capacity will decrease more rapidly, even if there is ample capacity to meet the load requirements.

The Surveillance Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 18 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's rating. Degradation is indicated, according to IEEE-450, 1975 (Ref. 14), when the battery capacity drops by more than 10% relative to its average on previous performance tests or when it is below 90% of the manufacturer's rating. For the 250 V battery, degradation is indicated when it is below 93.4% of the manufacturer's rating in lieu of 90%. This ensures the accelerated testing schedule is implemented when the 250 V battery capacity decreases to 10% above the capacity at which the battery must be replaced (consistent with the 125 V batteries), since the 250 V battery must be replaced when the capacity falls to 83.4%. The 12 month and 60 month Frequencies are consistent with the recommendations in IEEE-450 (Ref. 11). The 24 month Frequency is derived from the recommendations in IEEE-450 (Ref. 11). (B) (B)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.

2. Regulatory Guide 1.6, Revision 0, March 10, 1971.

3. IEEE Standard 308, 1974.

4. FSAR, Section 8.3.2.

(continued)

BASES

BACKGROUND (continued)

by an electronic load cell. The fuel grapple and frame-mounted hoist load signals are inputs to a programmable logic controller (PLC). The PLC performs the associated interlock and load functions. The trolley-mounted hoist load cell inputs to setpoint modules that perform their associated interlock and load functions. The PLC and setpoint modules open the associated fuel-loaded circuits at a load lighter than the weight of a single fuel assembly in water. The refueling interlocks use these indications to prevent operation of the refueling equipment with fuel loaded over the core whenever any control rod is withdrawn, or to prevent control rod withdrawal whenever fuel loaded refueling equipment is over the core (Ref. 2).

APPLICABLE SAFETY ANALYSES

The refueling interlocks are explicitly assumed in the FSAR analysis of the control rod removal error during refueling (Ref. 3). This analysis evaluates the consequences of control rod withdrawal during refueling. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment.

Criticality and, therefore, subsequent prompt reactivity excursions are prevented during the insertion of fuel, provided all control rods are fully inserted during the fuel insertion. The refueling interlocks accomplish this by preventing loading fuel into the core with any control rod withdrawn, or by preventing withdrawal of a rod from the core during fuel loading.

The refueling platform location switches activate at a point outside of the reactor core, such that, with a fuel assembly loaded and a control rod withdrawn, the fuel is not over the core.

Refueling equipment interlocks satisfy Criterion 3 of the NRC Policy Statement (Ref. 4).

LCO

To prevent criticality during refueling, the refueling interlocks associated with the refuel position ensure that fuel assemblies are not loaded into the core with any control rod withdrawn. 12

(continued)

BASES

LCO (continued)

To prevent these conditions from developing, the all-rods-in, the refueling platform position, the refueling platform fuel grapple fuel-loaded, the refueling platform frame-mounted hoist fuel-loaded, and the refueling platform trolley-mounted hoist fuel-loaded inputs are required to be OPERABLE. These inputs are combined in logic circuits that provide refueling equipment or control rod blocks to prevent operations that could result in criticality during refueling operations.

APPLICABILITY

In MODE 5, a prompt reactivity excursion could cause fuel damage and subsequent release of radioactive material to the environment. The refueling equipment interlocks protect against prompt reactivity excursions during MODE 5. The interlocks are only required to be OPERABLE during in-vessel fuel movement with refueling equipment associated with the interlocks when the reactor mode switch is in the refuel position. The interlocks are not required when the reactor mode switch is in the shutdown position since a control rod block (LCO 3.3.2.1, "Control Rod Block Instrumentation") ensures control rod withdrawals cannot occur simultaneously with in-vessel fuel movements.

In MODES 1, 2, 3, and 4, the reactor pressure vessel head is on, and no fuel loading activities are possible. Therefore, the refueling interlocks are not required to be OPERABLE in these MODES.

ACTIONS

A.1

With one or more of the required refueling equipment interlocks inoperable, the unit must be placed in a condition in which the LCO does not apply. In-vessel fuel movement with the affected refueling equipment must be immediately suspended. This action ensures that operations are not performed with equipment that would potentially not be blocked from unacceptable operations (e.g., loading fuel into a cell with a control rod withdrawn). Suspension of in-vessel fuel movement shall not preclude completion of movement of a component to a safe position.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

Performance of a CHANNEL FUNCTIONAL TEST demonstrates each required refueling equipment interlock will function properly when a simulated or actual signal indicative of a required condition is injected into the logic. The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping, or total channel steps so that the entire channel is tested.

The 7 day Frequency is based on engineering judgment and is considered adequate in view of other indications of refueling interlocks and their associated input status that are available to unit operations personnel.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.

2. FSAR, Section 7.7.1.13.

3. FSAR, Section 15.4.1.1.

4. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

B 3.9 REFUELING OPERATIONS

B 3.9.6 Reactor Pressure Vessel (RPV) Water Level – Irradiated Fuel

BASES

BACKGROUND

The movement of irradiated fuel assemblies within the RPV requires a minimum water level of 22 ft above the top of the RPV flange. During refueling, this maintains a sufficient water level in the reactor vessel cavity and spent fuel storage pool. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Refs. 1 and 2). Sufficient iodine activity would be retained to limit offsite doses from the accident to < 25% of 10 CFR 100 limits, as provided by the guidance of Reference 3. (B)

APPLICABLE SAFETY ANALYSES

During movement of irradiated fuel assemblies the water level in the RPV is an initial condition design parameter in the analysis of a fuel handling accident in containment postulated by Regulatory Guide 1.25 (Ref. 1). A minimum water level of 23 ft (Regulatory Position C.1.c of Ref. 1) allows a decontamination factor of 100 (Regulatory Position C.1.g of Ref. 1) to be used in the accident analysis for iodine. This relates to the assumption that 99% of the total iodine released from the pellet to cladding gap of all the dropped fuel assembly rods is retained by the refueling cavity water. The fuel pellet to cladding gap is assumed to contain 10% of the total fuel rod iodine inventory (Ref. 1).

Analysis of the fuel handling accident inside containment is described in Reference 2. With a minimum water level of 22 ft (a decontamination factor of 100 is still expected at a water level as low as 22 ft) and a minimum decay time of 24 hours prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water, and that offsite doses are maintained within allowable limits (Ref. 4). While the worst case assumptions include the dropping of the irradiated fuel assembly being handled onto the reactor core, the possibility exists of the dropped assembly striking the RPV flange and releasing fission products. Therefore, the minimum depth for water coverage to ensure acceptable radiological consequences is specified from the RPV flange. Since the worst case event

(continued)

B 3.9 REFUELING OPERATIONS

B 3.9.8 Residual Heat Removal (RHR)–High Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 5 is to remove decay heat and sensible heat from the reactor coolant, as required by GDC 34 (Ref. 1). Each of the two shutdown cooling loops of the RHR System can provide the required decay heat removal. Each loop consists of one motor driven pump, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchanger, to the reactor via the associated recirculation loop. The RHR heat exchangers transfer heat to the Standby Service Water (SW) System. The RHR shutdown cooling mode is manually controlled. (B)

In addition to the RHR subsystems, the volume of water above the reactor pressure vessel (RPV) flange provides a heat sink for decay heat removal.

APPLICABLE SAFETY ANALYSES

With the unit in MODE 5, the RHR Shutdown Cooling System is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR Shutdown Cooling System is required for removing decay heat to maintain the temperature of the reactor coolant.

The RHR System satisfies Criterion 4 of the NRC Policy Statement (Ref. 2).

LCO

Only one RHR shutdown cooling subsystem is required to be OPERABLE in MODE 5 with irradiated fuel in the RPV and the water level $\geq$ 22 ft above the RPV flange. Only one subsystem is required because the volume of water above the RPV flange provides backup decay heat removal capability.

An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, a heat exchanger, a SW pump providing cooling to the heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path.

(continued)

B 3.9 REFUELING OPERATIONS

B 3.9.9 Residual Heat Removal (RHR)—Low Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 5 is to remove decay heat and sensible heat from the reactor coolant, as required by GDC 34 (Ref. 1). Each of the two shutdown cooling loops of the RHR System can provide the required decay heat removal. Each loop consists of one motor driven pump, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchanger, to the reactor via the associated recirculation loop. The RHR heat exchangers transfer heat to the Standby Service Water (SW) System. The RHR shutdown cooling mode is manually controlled. (B)

APPLICABLE SAFETY ANALYSES

With the unit in MODE 5, the RHR Shutdown Cooling System is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR Shutdown Cooling System is required for removing decay heat to maintain the temperature of the reactor coolant.

The RHR System satisfies Criterion 4 of the NRC Policy Statement (Ref. 2).

LCO

In MODE 5 with irradiated fuel in the reactor pressure vessel (RPV) and the water level < 22 ft above the reactor pressure vessel (RPV) flange both RHR shutdown cooling subsystems must be OPERABLE.

An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, a heat exchanger, a SW pump providing cooling to the heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path.

Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one subsystem can maintain and reduce the reactor coolant temperature as required. However, to ensure adequate core

(continued)

BASES

LCO (continued)

criticality upon withdrawal of this control rod. Also, once this alternate (Item c.2) is completed, the SDM requirement to account for both the withdrawn-untrippable control rod and the highest worth control rod may be changed to allow the withdrawn-untrippable control rod to be the single highest worth control rod.

APPLICABILITY

Control rod withdrawals are adequately controlled in MODES 1, 2, and 5 by existing LCOs. In MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with Special Operations LCO 3.10.3, or this Special Operations LCO, and if limited to one control rod. This allowance is only provided with the reactor mode switch in the refuel position.

During these conditions, the full insertion requirements for all other control rods, the one-rod-out interlock (LCO 3.9.2), control rod position indication (LCO 3.9.4), and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," LCO 3.3.8.2, "Reactor Protection System (RPS) Electric Power Monitoring," and LCO 3.9.5, "Control Rod OPERABILITY – Refueling"), or the added administrative controls in Item b.2 and Item c.2 of this Special Operations LCO, provide mitigation of potential reactivity excursions. A

ACTIONS

A Note has been provided to modify the ACTIONS related to a single control rod withdrawal while in MODE 4. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

(continued)

BASES

ACTIONS

A.1 (continued)

not accomplished, operation may continue, provided the control rods are fully inserted within 3 hours and disarmed (electronically or hydraulically) within 4 hours. Inserting a control rod ensures the shutdown and scram capabilities are not adversely affected. The control rod is disarmed to prevent inadvertent withdrawal during subsequent operations. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically, the control rods can be disarmed by disconnecting power from all four directional control valve solenoids. Required Action A.1 is modified by a Note that allows the RWM to be bypassed if required to allow insertion of the inoperable control rods and continued operation. LCO 3.3.2.1, "Control Rod Block Instrumentation," ACTIONS provide additional requirements when the RWM is bypassed to ensure compliance with the CRDA analysis.

The allowed Completion Times are reasonable, considering the small number of allowed inoperable control rods, and provide time to insert and disarm the control rods in an orderly manner and without challenging plant systems.

Condition A is modified by a Note allowing separate Condition entry for each uncoupled control rod. This is acceptable since the Required Actions for this Condition provide appropriate compensatory actions for each uncoupled control rod. Complying with the Required Actions may allow for continued operation. Subsequent uncoupled control rods are governed by subsequent entry into the Condition and application of the Required Actions.

B.1

With one or more of the requirements of this LCO not met, for reasons other than an uncoupled control rod, the testing should be immediately stopped by placing the reactor mode switch in the shutdown or refuel position. This results in a condition that is consistent with the requirements for MODE 5 where the provisions of this Special Operations LCO are no longer required.

(continued)

END OF CYCLE (EOC)

1.12A The END-OF-CYCLE (EOC) shall be the core exposure at which rated thermal power, rated core flow, and rated feedwater temperature would all be achieved if all control rods were fully withdrawn.

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

1.13 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be that time interval from initial signal generation by the associated (EOC-RPT) breaker trip coil to energization of the recirculation pump circuit breaker trip coil from when the monitored parameter exceeds its trip setpoint at the channel sensor of the associated:

a. Turbine throttle valve, limit switch or from when the hydraulic control oil pressure drops below the pressure switch setpoint, and
b. Turbine governor valve, initiation of valve fast closure.

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

FINAL FEEDWATER TEMPERATURE REDUCTION (FFTR)

1.13A FINAL FEEDWATER TEMPERATURE REDUCTION (FFTR) shall be operation at or beyond EOC for the purpose of extending the normal fuel cycle by plant operation with a final feedwater temperature reduced from the normal rated power temperature condition.

FRACTION OF LIMITING POWER DENSITY

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

insert into MFLPD definition on page 1-4

FRACTION OF RATED THERMAL POWER

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

FREQUENCY NOTATION

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

1.17 Not Used

IDENTIFIED LEAKAGE

1.18 IDENTIFIED LEAKAGE shall be LEAKAGE shall be:

a. Leakage into the drywell that is from collection systems, such as pump seals or valve packing leaks, that is captured and conducted to a sump or collecting tank, or

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

ISOLATION SYSTEM RESPONSE TIME

1.19 The ISOLATION SYSTEM RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its isolation actuation setpoint at the channel sensor until the isolation valves travel to their required positions. Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.

INSTRUMENTATION initiation receive the isolation signal (e.g., de-energization of the MSIV solenoids) means of

A.25

INSERT 4

to complete suppression of the electric arc between the fully open contacts of the recirculation pump circuit breaker.

B

LIMITING CONTROL ROD PATTERN

1.20 A LIMITING CONTROL ROD PATTERN shall be a pattern which results in the core being on a thermal-hydraulic limit, i.e., operating on a limiting value for APLHGR, LHGR, or MCPR.

LINEAR HEAT GENERATION RATE (LHGR)

1.21 ~~LINEAR HEAT GENERATION RATE (LHGR)~~ The LINEAR HEAT GENERATION RATE (LHGR) shall be the heat generation per unit length of fuel rod. It is the integral of the heat flux over the heat transfer area associated with the unit length.

LOGIC SYSTEM FUNCTIONAL TEST

1.22 A LOGIC SYSTEM FUNCTIONAL TEST shall be a test of all logic components, i.e., all relays and contacts, ~~all~~ trip units, solid state logic elements, etc.) of a logic circuit, from sensor ~~through and~~ including the actuated device, to verify OPERABILITY. The LOGIC SYSTEM FUNCTIONAL TEST may be performed by any series of sequential, overlapping or total system steps ~~such~~ that the entire logic system is tested.

MAXIMUM FRACTION OF LIMITING POWER DENSITY (MFLPD)

1.23 ~~The MAXIMUM FRACTION OF LIMITING POWER DENSITY (MFLPD)~~ shall be ~~largest~~ highest value of the ~~FLPD which exists~~ in the core.

Insert definition of FLPD from page 1-3

MAXIMUM TOTAL PEAKING FACTOR

1.24 The MAXIMUM TOTAL PEAKING FACTOR (MTPF) shall be the largest ~~TPF~~ which exists in the core for a given class of fuel for a given operating condition.

MEMBER(S) OF THE PUBLIC

1.25 MEMBER(S) OF THE PUBLIC shall include all persons who are not occupationally associated with the plant. This category does not include employees of the utility, its contractors or vendors. Also excluded from this category are persons who enter the site to service equipment or to make deliveries. This category does include persons who use portions of the site for recreational, occupational or other purposes not associated with the plant.

MINIMUM CRITICAL POWER RATIO (MCPR)

1.26 The ~~MINIMUM CRITICAL POWER RATIO (MCPR)~~ shall be the smallest ~~CPR~~ which exists in the core.

Insert definition of CPR from pg 1-2

ADMINISTRATIVE (continued)

A.6 The definitions of CRITICAL POWER RATIO and FRACTION OF LIMITING POWER DENSITY, as editorially marked up, have been incorporated into the definitions of MINIMUM CRITICAL POWER RATIO and MAXIMUM FRACTION OF LIMITING POWER DENSITY, respectively. No separate use of CPR or FLPD is made in the WNP-2 ITS.

A.7 The definition of FREQUENCY NOTATION has been deleted since the abbreviations in Table 1.1 are no longer used. All Surveillance Requirement Frequencies in the WNP-2 ITS are directly specified.

A.8 The definitions for IDENTIFIED LEAKAGE, PRESSURE BOUNDARY LEAKAGE, and UNIDENTIFIED LEAKAGE have been combined into one defined term: LEAKAGE. The definitions of each of the categories of leakage are consistent with the current WNP-2 definitions.

The WNP-2 ITS definition of Total LEAKAGE has been added for clarity and completeness. The WNP-2 CTS use of the undefined term "total leakage" is consistent with the WNP-2 ITS definition.

A.9 As specified in the second portion of the WNP-2 definition, the intended leakage is that which occurs into the drywell space. The "collection systems" are intended to be those for collection of leakages into the drywell space. This change is a clarification of the term, and therefore the revised wording more accurately reflects this intent.

A.10 The ISOLATION SYSTEM RESPONSE TIME definition has been modified to only include the instrumentation portion of the response time. The isolation valve portion of the response time (i.e., valve stroke times) does not need to be included since it is redundant to the valve stroke time requirements specified in ASME Section XI, which is required by Specification 5.5.6, the IST Program. In addition, specific Surveillance Requirements in LCO 3.6.1.3, Primary Containment Isolation Valves, also require the valve stroke times to be verified. The requirement to include diesel generator starting and loading times has been deleted since they are redundant to the diesel generator Surveillance Requirements in LCO 3.8.1, AC Sources—Operating. This deletion was recommended in both NUREG-1366 and Generic Letter 93-05. Due to these changes, the definition has been renamed to be ISOLATION INSTRUMENTATION RESPONSE TIME. Since the actual technical requirements are not changing, this change is considered administrative.

A.11 Not used. (B)

A.1

2.0 SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS *Moved to LCO 3.3.1.1*

2.1 SAFETY LIMITS

THERMAL POWER, Low Pressure or Low Flow

2.1.1 THERMAL POWER shall not exceed 25% of RATED THERMAL POWER with the reactor vessel steam dome pressure less than 785 psig or core flow less than 10% of rated flow.

2.1.1.1

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2. M.1

ACTION:

2.2 With THERMAL POWER exceeding 25% of RATED THERMAL POWER and the reactor vessel steam dome pressure less than 785 psig or core flow less than 10% of rated flow, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.7.1. A.2 B

THERMAL POWER, High Pressure and High Flow

2.1.2 The MINIMUM CRITICAL POWER RATIO (MCPR) shall not be less than 1.07 with two recirculation loop operation and shall not be less than 1.08 with single recirculation loop operation with the reactor vessel steam dome pressure greater than 785 psig and core flow greater than 10% of rated flow.

2.1.1.2

M.2

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2. M.1

ACTION:

M.2

2.2 With MCPR less than 1.07 with two recirculation loop operation or less than 1.08 with single recirculation loop operation and the reactor vessel steam dome pressure greater than 785 psig and core flow greater than 10% of rated flow, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.7.1. A.2 B

REACTOR COOLANT SYSTEM PRESSURE

2.1.3 The reactor coolant system pressure, as measured in the reactor vessel steam dome, shall not exceed 1325 psig.

2.1.2

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, and 4. M.1

ACTION:

2.2 With the reactor coolant system pressure, as measured in the reactor vessel steam dome, above 1325 psig, be in at least HOT SHUTDOWN with reactor coolant system pressure less than or equal to 1325 psig within 2 hours and comply with the requirements of Specification 6.7.1. A.2 B

SAFETY LIMITS (Continued)

REACTOR VESSEL WATER LEVEL

2.1.1.3 2.1.4 The reactor vessel water level shall be above the top of the active irradiated fuel.

APPLICABILITY: OPERATIONAL CONDITIONS 3, 4 and 5 (M.1)

ACTION:

2.2 With the reactor vessel water level at or below the top of the active irradiated fuel, manually initiate the ECCS to restore the water level, after depressurizing the reactor vessel, if required. Comply with the requirements of Specification 6.7.1. (LA.1) (A.2) | B

2.2 LIMITING SAFETY SYSTEM SETTINGS

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

2.2.1 The reactor protection system instrumentation setpoints shall be set consistent with the Trip Setpoint values shown in Table 2.2.1-1.

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

With a reactor protection system instrumentation setpoint less conservative than the value shown in the Allowable Values column of Table 2.2.1-1, declare the channel inoperable and apply the applicable ACTION statement requirement of Specification 3.3.1 until the channel is restored to OPERABLE status with its setpoint adjusted consistent with the Trip Setpoint value.

A.1

moved to LCO 3.3.1.1

TABLE 2.2.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Intermediate Range Monitor, Neutron Flux - High	≤ 120/125 divisions of full scale	≤ 122/125 divisions of full scale
2. Average Power Range Monitor:		
a. Neutron Flux-High, Setdown	≤ 15% of RATED THERMAL POWER	≤ 20% of RATED THERMAL POWER
b. Flow Biased Simulated Thermal Power - High		
1) Flow Biased	≤ 0.58W + 59%, with a maximum of	≤ 0.58W + 62%, with a maximum of
2) High Flow Clamped	≤ 113.5% of RATED THERMAL POWER	≤ 114.9% of RATED THERMAL POWER
c. Fixed Neutron Flux - High	≤ 118% of RATED THERMAL POWER	≤ 120% of RATED THERMAL POWER
d. Inoperative	N.A.	N.A.
3. Reactor Vessel Steam Dome Pressure - High	≤ 1060 psig	≤ 1074 psig
4. Reactor Vessel Water Level - Low, Level 3	≥ 13.0 inches above Instrument zero*	≥ 11.0 inches above Instrument zero
5. Main Steam Line Isolation Valve - Closure	≤ 10.0% closed	≤ 12.5% closed
6. DELETED		

*See Bases Figure B 3/4 3-1.

A-1 moved to LCO 3.3.1.1

Chapter 2-0

Page 4 of 5

TABLE 2.2.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE ALLOWABLE VALUES
7. Primary Containment Pressure - High	≤ 1.68 psig	≤ 1.88 psig
8. Scram Discharge Volume Water Level - High		
a. Level Transmitter	≤ 529'7" elevation	≤ 529' 9" elevation
b. Float Switch	≤ 529'7" elevation	≤ 529' 9" elevation
9. Turbine Stop Valve - Closure	≤ 5% closed	≤ 7% closed
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≥ 1250 psig	≥ 1000 psig
11. Reactor Mode Switch Shutdown Position	N.A.	N.A.
12. Manual Scram	N.A.	N.A.

A.1 Moved to LCO 3.3.1.1

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DISCUSSION OF CHANGES
ITS: CHAPTER 2.0 - SAFETY LIMITS

ADMINISTRATIVE

A.1 The requirements for the Limiting Safety System Settings are being moved to Section 3.3 in accordance with the format of the BWR Standard Technical Specifications, NUREG-1434. Any technical changes to these requirements will be discussed in the Discussion of Changes for ITS: 3.3.1.1. (G)

A.2 The format of the proposed Technical Specifications does not include providing cross references. In addition, Specification 6.7.1 has been deleted from the Technical Specifications (see Discussion of Changes for CTS: 6.7 in proposed Chapter 5.0). Therefore, the existing reference to Specification 6.7.1 serves no functional purpose and its removal is an administrative change. (B)

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 The APPLICABILITY of each of the SLs is extended to all MODES of operation. Although it is physically impossible to violate some SLs in some MODES, any SL violation should receive the same attention and response.

M.2 Limits on steam dome pressure and core flow are now specified as "greater than or equal to." The current Safety Limits do not address the situation when steam dome pressure and core flow are equal to the limits. This change resolved a discontinuity between SL 2.1.1 and SL 2.1.2 in the current Safety Limits. (B)

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The required action of CTS 2.1.4 has been made less specific to allow operator flexibility in determining the best method to restore the reactor vessel water level. Directions for the methods of restoring reactor vessel water level (manually initiate the ECCS to restore the water level, after depressurizing the reactor vessel, if required) are proposed to be relocated to the appropriate Emergency Operating Procedures. This detail of how to restore the reactor vessel water level is not necessary to ensure restoration of the reactor vessel water level in a timely manner. The action to restore compliance with the Safety Limit has been maintained in ITS SL 2.2.1, which provides a 2 hour Completion Time for restoration of the limit. The time frame for completion of the action is consistent with the allowed time to restore other Safety Limit violations and allows appropriate actions to be evaluated by the operator and completed in a timely manner. Changes to the relocated requirements in plant procedures will be controlled by the provisions of 10 CFR 50.59. (B) (B)

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

"Specific"

None

Specification 3.1.3

REACTIVITY CONTROL SYSTEMS

3/4.1.3 CONTROL RODS

CONTROL ROD OPERABILITY

LIMITING CONDITION FOR OPERATION (A.1 <general reorganization>)

LCO 3.1.3

3.1.3.1 All control rods shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION: (add proposed ACTIONS Note A.2) (add proposed Required Action A.1 Note A.3)

ACTION A a. With 1 control rod inoperable due to being immovable, as a result of excessive friction or mechanical interference, or known to be untrippable: (A.4)

1. Within 1 hour: (L.1 ACTION D)

a) Verify that the inoperable control rod, if withdrawn, is separated from all other inoperable control rods by at least two control cells in all directions. (M.1)

b) Disarm the associated directional control valves** either: (L.2 Required Actions A.2 and A.4) (LA.1)

1) Electrically, or

2) Hydraulically by closing the drive water and exhaust water isolation valves.

c) Comply with Surveillance Requirement 4.1.1.c.

(add proposed Required Action A.1) (L.3)

ACTION F (M.2) Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

2. Restore the inoperable control rod to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours. (L.3)

(add proposed ACTION B)

b. With one or more control rods trippable but inoperable for causes other than addressed in ACTION a, above:

ACTION C 1. If the inoperable control rod(s) is withdrawn, within 1 hour: (M.1)

a) Verify that the inoperable withdrawn control rod(s) is separated from all other inoperable withdrawn control rods by at least two control cells in all directions, and (L.1 ACTION D)

b) Demonstrate the insertion capability of the inoperable withdrawn control rod(s) by inserting the control rod(s) at least one notch by drive water pressure within the normal operating range*. (L.4 Required Actions C.2 and C.3) (A.3) (M.3)

Otherwise, insert the inoperable withdrawn control rod(s) and disarm the associated directional control valves** either: (LA.1) (add proposed Required Action C.2 Note) (A.21)

*The inoperable control rod may then be withdrawn to a position no further withdrawn than its position when found to be inoperable.

**May be rearmed intermittently, under administrative control, to permit testing associated with restoring the control rod to OPERABLE status. (A.5)

TECHNICAL CHANGES - LESS RESTRICTIVE

L.3 (cont'd) (proposed Required A.3). Therefore, continued operation is proposed to be allowed, as are MODE changes in accordance with SR 3.0.4.

L.4 All inoperable non-stuck control rods are required to be fully inserted and disarmed (refer to comment M.3 above). The time allowed to complete the insertion is proposed to be extended to 3 hours for all cases. In the existing ACTIONS for an uncoupled control rod (LCO 3.1.3.6, ACTION a.2), time is provided to recouple and, if unsuccessful, insert the control rod before entering LCO 3.1.3.1, ACTION b.1. Two hours are currently allowed to perform these ACTIONS. LCO 3.1.3.1, ACTION b.1, gives an additional 1 hour to disarm the control rod (total of 3 hours to insert and disarm). Uncoupled control rod actions are proposed to be addressed by LCO 3.1.3, ACTION C, as are other non-stuck inoperable control rods. This existing 3 hour allowance, before requiring an inoperable (uncoupled) control rod to be inserted, is the time found in the proposed Required Action C.2 for control rod insertion. For consistency of presentation, this 3 hour limitation is also proposed for all other instances of inoperable control rods. These other instances (loss of position indication, excessive scram speed, certain combinations of conditions with a low pressure on a control rod scram accumulator) also warrant a minimal time to attempt restoration prior to inserting and disarming. It is for these other instances that the extended time to insert are proposed. Since these instances do not represent loss of SDM, and are limited to a total of no more than 8 inoperable control rods, the extended time does not represent a significant safety concern. (Refer to proposed ACTION F.) 1B

Disarming a control rod can involve personnel actions by other than control room operating personnel. This process requires coordination of personnel and preparation of equipment, and potentially requires anti-contamination "dress-out," in addition to the actual procedure of disarming the control rod. Currently, all these activities must be completed and the control room personnel must confirm completion within the same 1 hour allowed to insert the control rod. The disarming is proposed to be extended to 4 hours -- 1 hour beyond that allowed to insert (consistent with the BWR Standard Technical Specifications, NUREG-1434) in recognition of the potential for excessive haste required to complete this task. The proposed 4 hour time does not represent a significant safety concern since the control rod is already in its required position (in accordance with other actions), and the action to disarm is solely a mechanism for precluding the potential for future misoperation.

L.5 The Surveillance verifying control rods to be non-stuck is proposed to be extended from 7 days to 31 days for control rods that are not fully withdrawn. This is consistent with the BWR Standard Technical Specifications, NUREG-1434. Partially withdrawn control rods have a significantly greater effect on core

TECHNICAL CHANGES - LESS RESTRICTIVE

L.8 (cont'd) not desirable. Because of the frequent testing of control rod insertion capability (proposed SR 3.1.3.2 and SR 3.1.3.3) and accumulator OPERABILITY (proposed SR 3.1.5.1), and the operating history demonstrating a high degree of reliability, the more frequent scram time testing is not necessary to assure safe plant operations. In addition, since the shutdown requirement could have only applied to this ACTION (since a control rod can always be declared inoperable), this ACTION has also been deleted.

L.9 Coupling requirements during refueling are not necessary since only one control rod can be withdrawn from core cells containing fuel assemblies. The probability and consequences of a single control rod dropping from its fully inserted position to the withdrawn position of the control rod drive are negligible (i.e., reactor will remain subcritical and within the limits of the CRDA assumptions). However, these requirements are retained for the proposed SDM testing in MODE 5 (proposed LCO 3.10.8).

L.10 If an uncoupled control rod is not allowed by the RWM to be inserted to accomplish recoupling, the current Technical Specifications require the control rod be inserted. This will require bypassing the RWM and operation with an out-of-sequence control rod. Therefore, coupling attempts are allowed regardless of the RWM allowance because of the short time allowed. If coupling is not established within 3 hours, the control rod must be fully inserted and disarmed (proposed Required Actions C.2 and C.3). Also, because of the limited time allowed to recouple, the number of attempts does not need to be restricted. The number of attempts to recouple a control rod may be restricted by plant procedures which consider the potential for equipment damage during successive recoupling attempts.

L.11 Proposed SR 3.1.3.5 verifies a control rod does not go to the withdrawn overtravel position. An uncoupled control rod would fail to meet SR 3.1.3.5. After restoration of a component that caused a required SR to be failed, SR 3.0.1 requires the appropriate SRs (in this case SR 3.1.3.5) to be performed to demonstrate the OPERABILITY of the affected components. The requirement to verify control rod coupling by observation of nuclear instrumentation response is addressed in comment L.12 of this LCO. As a result, the requirements are not necessary for ensuring recoupling of the control rod and are proposed to be deleted. 1 B

L.12 The requirement to verify control rod coupling by withdrawing a control rod and observing any indicated response of the nuclear instrumentation is proposed to be deleted. If sufficient friction is present to uncouple the control rod from its drive, the control rod would not follow the drive being withdrawn. In this case, neutron flux level change, if discernible, would be indicative of an uncoupled rod. However, this is not a positive check that the control rod is uncoupled since if sufficient friction is not

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

LA.4 The testing requirements of CTS 4.1.5.d.2 for SLC System relief valve setting verification is proposed to be relocated to the Inservice Testing (IST) Program. These testing requirements do demonstrate the SLC System relief valves are OPERABLE. However, the IST Program, required by 10 CFR 50.55a, provides requirements for the testing of all ASME Code Class 1, 2, and 3 valves in accordance with Section XI of the ASME Code. Compliance with 10 CFR 50.55a, and as a result the IST Program and implementing procedures, is required by the WNP-2 Operating License. These controls are adequate to ensure the required testing to demonstrate OPERABILITY is performed. Changes to the relocated requirements in the IST Program will be controlled by the provisions of 10 CFR 50.59.

LA.5 The contained tank volumes associated with the SLC storage tank low level and high level alarms are details of the system design and are proposed to be relocated to the Bases and FSAR. These design details are not necessary to ensure the OPERABILITY of the SLC System. SLC System OPERABILITY requirements are adequately addressed in Specification 3.1.7 and the definition of OPERABILITY. Changes to the Bases will be controlled by the provisions of the Bases Control Program described in Chapter 5 of the Technical Specifications. Changes to the FSAR will be controlled by the provisions of 10 CFR 50.59.

LD.1 The Frequencies for performing current Surveillances 4.1.5.d.1 and 4.1.5.d.3 (proposed SRs 3.1.7.7 and 3.1.7.8) have been extended from 18 months to 24 months to facilitate a change to the WNP-2 maintenance cycle from 12 months to 24 months. The current conditions in the northwest require that WNP-2 shut down each spring for an annual maintenance and refueling outage. Currently, most of the current Surveillances that are required to be performed on an 18 month interval are performed annually because they must be performed while the plant is shut down. This has resulted in increased testing, with a resultant increase in cost and personnel exposure, with no comparable increase in reliability or safety. This change is being proposed to support limiting the amount of surveillance testing that must be performed each maintenance and refueling outage. The proposed change will allow these Surveillances to extend their Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2). This proposed change was evaluated in accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991. Reviews of historical maintenance and surveillance data have shown that these tests normally pass their Surveillances at the current Frequency. An evaluation has been performed using

1 B

Table 3.3.1.1-1

TABLE 4.3.1.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	SR 3.3.1.1.1 CHANNEL CHECK	SRs 3.3.1.1.9, 3.3.1.1.8, 3.3.1.1.13 CHANNEL FUNCTIONAL TEST	SR 3.3.1.1.10 CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
~~7~~ 8. Scram Discharge Volume Water Level - High				
a. Level Transmitter	N.A.	Q-8	R-10	1, 2, 5(j)
b. Float switch	N.A.	Q-8	R-10	1, 2, 5(j)
~~8~~ 9. Turbine Throttle Valve - Closure	N.A.	Q-8	R-10	1
~~9~~ 10. Turbine Governor Valve Fast Closure Valve Trip System Oil Pressure - Low	N.A.	Q-8	R-10	1
~~10~~ 11. Reactor Mode Switch Shutdown Position	N.A.	13-(R) 24mos	N.A.	1, 2, 3, 4, 5
~~11~~ 12. Manual Scram	N.A.	W-4	N.A.	1, 2, 3, 4, 5

(1.2) add proposed SR 3.3.1.1.12

(D.1)

(B)

See markup of Table 3.3.1-1

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Specification 3.3.1.1

TABLE 4.3.1.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TABLE NOTATIONS

NOTE 1 to SRs 3.3.1.1.9 and 3.3.1.1.10

(a) Neutron detectors may be excluded from CHANNEL CALIBRATION.

LA.1

SR 3.3.1.1.5

(b) The IRM and SRM channels shall be determined to overlap ~~for at least~~ 1/2 decade during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap ~~for at least~~ 1/2 decade during each ~~controlled~~ shutdown, if not performed within the previous 7 days.

SR 3.3.1.1.6

~~(c) Within 24 hours prior to startup, if not performed within the previous 7 days.~~

A.9

Add proposed Note to SR 3.3.1.1.2

L.11

SR 3.3.1.1.2

(d) This calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER > 25% of RATED THERMAL POWER. Adjust the APRM channel if the absolute difference is greater than 2% of RATED THERMAL POWER. Any APRM channel gain adjustment made in compliance with Specification 3.2.2 shall not be included in determining the absolute difference.

L.9

SR 3.3.1.1.8

(e) This calibration shall consist of the adjustment of the APRM flow biased channel to conform to a calibrated flow signal.

SR 3.3.1.1.7

A.10 1130 MWD/T average core exposure

B

(f) The LPRMs shall be calibrated at least once per A.10 1000 effective full power hours (EFPH) using the TIP system. LA.1 A.11

A.10

~~(g) Measure and compare core flow to rated core flow.~~

LA.6

SR 3.3.1.1.11

(h) This calibration shall consist of verifying the ~~5 ± 1~~ ≤7 second simulated thermal power time constant.

~~(i) DELETED~~

L.4

(j) With any control rod withdrawn ~~from a core cell containing one or more fuel assemblies.~~ ~~Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.~~

A.8

Note a to Table 3.3.1.1-1

ADMINISTRATIVE (continued)

A.8 The proposed Applicability requires RPS Functions to be OPERABLE in MODE 5 only with any control rod withdrawn from a core cell containing one or more fuel assemblies. This Applicability is consistent with current Note h, but clarified by removing the cross references to the Special Operations LCOs.

A.9 The Surveillance Frequency of "S/U" and Note c, "within 24 hours prior to startup, if not performed within the previous 7 days," is redundant to the requirements of SR 3.0.4 which require the Surveillance to be performed and current prior to entry into the applicable operational conditions. Once the applicable conditions are entered, the periodic Surveillance Frequency provides adequate assurance of OPERABILITY, if required. Therefore, the removal of this Frequency is considered administrative.

A.10 The Frequency "one per 1000 Effective Full Power Hours (EFPH)" has been changed to "1130 MWD/T average core exposure." Both Frequencies consider the LPRM sensitivity changes based on operating experience, and represent roughly the same time interval (approximately 6 weeks). The unit change allows a more convenient tracking parameter since MWD/T is commonly calculated and recorded by the core monitoring software system. | B

A.11 The requirement to perform a daily check on the APRM Flow Biased Simulated Thermal Power–High Function has been deleted. This daily Surveillance provides information redundant to other Surveillance Requirements (i.e., 4.4.1.2.1 and 4.4.1.2.2). Additionally, no credit is taken for this Function in the safety analysis. Further, this Surveillance would introduce confusion with respect to the jet pump Surveillance contained in proposed SR 3.4.2.1, which requires that the recirculation loop (jet pump) flow be within 10% of the established pattern. Current Note (g) requires the core flow to be measured and compared with the rated core flow. This is essentially what proposed SR 3.4.2.1 performs, except without the limits that are specified in proposed SR 3.4.2.1. Therefore, since this Surveillance is redundant to current Specification 4.4.1.2.1 and 4.4.1.2.2, it is unnecessary and has been deleted.

A.12 The Safety Limits Table 2.2.1-1 has been combined with the current RPS Technical Specifications. The setpoints and associated interlocks are now in Table 3.3.1.1-1.

A.13 The proper names for the Functions have been provided. Since this change is only a change of nomenclature, it is considered administrative.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 With two channels inoperable for the same Function in the same trip system, an RPS scram due to that Function cannot occur. Therefore, 12 hours to restore the channels is not allowed. Proposed Condition C will limit the time to 1 hour when one automatic Function or both manual Functions lose RPS trip capability. This proposed ACTION will still allow one manual RPS Function to lose trip capability, since RPS trip capability is lost for only one of the two manual RPS Functions. Manual RPS trip capability is still provided in the control room by the other RPS manual Function, which is controlled by Technical Specifications. This change is an additional restriction on plant operation. (B)

M.2 A Surveillance has been added (proposed SR 3.3.1.1.12) to verify the automatic enabling of the Turbine Throttle Valve and Turbine Governor Valve scrams at ≥ 30% RTP. This is consistent with the BWR Standard Technical Specifications, NUREG-1434, and is an additional restriction on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 Details of the methods for performing Surveillances are proposed to be relocated to the Bases. These details are not necessary to ensure the OPERABILITY of the Reactor Protection System (RPS) Instrumentation. The requirements of Specification 3.3.1.1 and the associated Surveillance Requirements are adequate to ensure the RPS instrumentation are maintained OPERABLE. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LA.2 These details, relating to placing channels in trip, are proposed to be relocated to the Bases. The ACTIONS of Specification 3.3.1.1 ensure inoperable channels are placed in trip or the unit is placed in a non-applicable MODE or condition, as appropriate. As a result, the proposed relocated details are not necessary for ensuring the appropriate actions are taken in the event of inoperable RPS channels. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LA.3 Requirements for the removal of RPS shorting links are proposed to be relocated from the Technical Specifications. The shorting links are required to be removed with any control rod withdrawn from a core cell containing one or more fuel assemblies when SHUTDOWN MARGIN has not been demonstrated. The primary reactivity control functions during refueling are the refueling interlocks and the SHUTDOWN MARGIN. The refueling interlocks are required to be OPERABLE by LCO 3.9.1 and LCO 3.9.2. Although SHUTDOWN MARGIN

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.3 (cont'd) may not yet have been demonstrated in MODE 5, SHUTDOWN MARGIN calculations would have been performed and, along with procedural compliance for any CORE ALTERATIONS, would provide indication that adequate SHUTDOWN MARGIN is available. In addition to SRM OPERABILITY with shorting links removed, IRM OPERABILITY will continue to provide backup for the credited functions for any significant reactivity excursions. Since the SRM channel high flux scram (with shorting links removed) provides only an uncredited backup in MODE 5, the relocation of the shorting link removal requirement does not significantly affect safety. Details for control of shorting link removal will be controlled by plant procedures. Changes to the relocated requirements in procedures will be controlled by the provisions of 10 CFR 50.59.

LA.4 The LPRM inputs for OPERABILITY of the APRM are proposed to be relocated to the Bases. The Bases states that if sufficient LPRMs are not available (the same number as in current Table 3.3.1-1, Note c), then the associated APRM is inoperable. As such, these details are not necessary in the RPS Instrumentation Tables. The definition of OPERABILITY suffices. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LA.5 Current Note (d) to Table 3.3.1-1 states the Main Steam Isolation Valve—Closure Function shall be automatically bypassed when the reactor mode switch is not in run and reactor pressure is < 1060 psig, current Note (g) to Table 3.3.1-1 states that the Primary Containment Pressure—High Function also actuates the Standby Gas Treatment System, current Note (i) to Table 3.3.1-1 states that the Turbine Throttle Valve—Closure and the Turbine Governor Valve Fast Closure, Valve Trip System Oil Pressure—Low Functions are automatically bypassed based on turbine first stage pressure when THERMAL POWER is less that 30% of RATED THERMAL POWER, and current Note (j) to Table 3.3.1-1 states that Turbine Throttle Valve—Closure and the Turbine Governor Valve Fast Closure, Valve Trip System Oil Pressure—Low Functions also actuate the EOC-RTP System. These system design details are proposed to be relocated to the FSAR. These are design details that are not necessary to be included in the Technical Specifications to ensure the OPERABILITY of the RPS instrumentation since OPERABILITY requirements are adequately addressed in Specification 3.3.1.1. In addition, the Applicabilities for the Turbine Throttle Valve—Closure and the Turbine Governor Valve Fast Closure, Valve Trip System Oil Pressure—Low Functions have been modified to be ≥ 30% RTP, consistent with the design and current Note (i), and the reference to turbine first stage pressure in ACTION 6 has been relocated to the FSAR since it describes how the 30% RTP signal is generated. Changes to the FSAR will be controlled by the provisions of 10 CFR 50.59. (2)

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

LA.6 The minimum thermal power time constant limit is proposed to be relocated to plant procedures. If the actual time constant is less than the minimum time, then the Function will cause an RPS trip sooner than is required. While this may be undesirable from an availability standpoint, it does not necessarily negatively impact safety. Other RPS Allowable Values only list the minimum or maximum values, not both, even though WNP-2 has a range to which the actual setpoint is set. In addition, the APRM Flow Biased Simulated Thermal Power-High Function is not assumed in any safety analysis. Changes to the relocated requirements in procedures will be controlled by the provisions of 10 CFR 50.59.

LA.7 Trip setpoints are an operational detail that is not directly related to the OPERABILITY of the instrumentation. These details are proposed to be relocated to plant procedures. The Allowable Value is the required limitation for the parameter and this value is retained in the Technical Specifications. Changes to the relocated trip setpoints in procedures will be controlled by the provisions of 10 CFR 50.59.

LB.1 The allowed out of service time (AOT) for placing the channel or trip system in trip is extended to 6 hours for the first trip system and 12 hours for the second trip system. This AOT has been shown to maintain an acceptable risk in accordance with previously conducted reliability analyses (NEDC-30851-P-A, March 1988). The results of the NRC review of this generic reliability analysis as it relates to WNP-2 is documented in NRC Safety Evaluation Report (SER) dated December 4, 1990. The SER concluded that the generic reliability analysis is applicable to WNP-2, and that WNP-2 meets all requirements of the NRC SER accepting the generic reliability analysis. (B)

LD.1 The Frequencies for performing the LOGIC SYSTEM FUNCTIONAL TEST and RPS RESPONSE TIME TEST requirements of current Surveillance 4.3.1.2 (proposed SRs 3.3.1.1.14 and 3.3.1.1.15) and the CHANNEL FUNCTIONAL TEST requirement of current Surveillance 4.3.1.1 (proposed SR 3.3.1.1.13) for Functional Unit 11, the Reactor Mode Switch Shutdown Position, have been extended from 18 months to 24 months to facilitate a change to the WNP-2 maintenance cycle from 12 months to 24 months. The current conditions in the northwest require that WNP-2 shut down each spring for an annual maintenance and refueling outage. Currently, most of the current Surveillances that are required to be performed on an 18 month interval are performed annually because they must be performed while the plant is shut down. This has resulted in increased testing, with a resultant increase in cost and personnel exposure, with no comparable increase in reliability or safety. This change is being proposed to support limiting the amount of surveillance testing that must be performed each maintenance and refueling outage. The proposed change will allow these Surveillances to extend their Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd) for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2). This proposed change was evaluated in accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991. Reviews of historical maintenance and surveillance data have shown that these tests normally pass their Surveillances at the current Frequency. An evaluation has been performed using this data, and it has been determined that the effect on safety due to the extended Surveillance Frequency will be small. In addition, the proposed 24 month Surveillance Frequencies, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) do not invalidate any assumptions in the plant licensing basis.

LF.1 This change revises the Technical Specification setpoints for proposed Section 3.3 instrumentation to reflect Allowable Values consistent with the philosophy of NUREG-1434. These Allowable Values (to be included in Technical Specifications) have been established consistent with the WNP-2 Instrument Setpoint Methodology. The Allowable Value selection evaluation used actual WNP-2 operating and surveillance trend information to ensure the validity of the evaluation input data. All changes to safety analysis limits, applied in the methodologies, were evaluated and confirmed as ensuring safety analysis licensing acceptance limits are maintained. All design limits, applied in the methodologies, were confirmed as ensuring that applicable design requirements of the associated systems are maintained. The methodologies used to derive the Allowable Values are based on combining the uncertainties of the associated channels. The methodologies used in the evaluation are consistent with the guidance of ISA Standard, SP67.04-1982, "Setpoints for Nuclear Safety-Related Instruments used in Nuclear Power Plants," which was approved for use by the NRC in RG 1.105, Revision 2, February 1986. Plant calibration procedures will ensure the assumptions regarding calibration accuracy are maintained. The proposed Allowable Values have been established from each design or safety analysis limit by accounting for instrument accuracy, calibration and drift uncertainties, environmental effects, power supply fluctuations, as well as uncertainties related to process and primary element measurement accuracy using the WNP-2 Instrument Setpoint Methodology. The use of these methodologies for establishing Allowable Values ensures design or safety analysis limits are not exceeded in the event of transients or accidents and accounts for uncertainties and environmental conditions.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.7 A Proposed Note to SR 3.3.1.1.3, Note 2 to SR 3.3.1.1.9, and Note 2 to SR 3.3.1.1.10 are being added to exempt the CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION requirements until 12 hours after entering MODE 2 from MODE 1. The IRM and APRM setdown functions are required in MODE 2, but not in MODE 1, and the required surveillances cannot be performed in MODE 1 (prior to entry in the applicable MODE 2) without utilizing jumpers or lifted leads. Use of these devices is not recommended since minor errors in their use may significantly increase the probability of a reactor transient or event which is a precursor to a previously analyzed accident. Therefore, time is allowed to conduct the SRs after entering the applicable MODE. This Frequency is consistent with the BWR Standard Technical Specifications, NUREG-1434.

L.8 These surveillance tests are required to be performed periodically (quarterly) while in the applicable MODES, as required by SR 3.0.1, and must be current prior to entering the applicable MODES, as required by SR 3.0.4. The required periodic Frequency has been determined to be sufficient verification that the APRMs are properly functioning. Performing a reactor startup does not impact the ability of the monitors to perform their required function. Therefore, an additional surveillance required to be performed "prior to a reactor startup" is an extraneous and unnecessary performance of a surveillance.

L.9 The Frequency for performing this Surveillance (current Note e) has been extended from 7 days to 92 days, as part of the CHANNEL FUNCTIONAL TEST requirement for the APRM Flow Biased Simulated Thermal Power–High Function (current WNP-2 requirements test this feature as part of a CHANNEL FUNCTIONAL TEST in addition to its normally required 7 day Surveillance Frequency, since this test is really a CHANNEL FUNCTIONAL TEST, not a CHANNEL CALIBRATION). A review of historical maintenance and surveillance data for the past two years has shown that this test always passes the Surveillance at the current Frequency (i.e., the instruments have never been required to be adjusted due to a failure of this Surveillance). An evaluation has been performed using this data, and it has been determined that the effect on safety due to the extended Surveillance Frequency will be small. The effect of the increased interval on instrument drift has also been considered in this evaluation. In addition, the proposed 92 day Surveillance Frequency, if performed at the maximum interval allowed by SR 3.0.2 (115 days) does not invalidate any assumptions in the plant licensing basis.

L.10 The CHANNEL CHECK requirement for the Reactor Vessel Steam Dome Pressure–High Function is being deleted. Pressure switches are used by WNP-2 to perform this RPS Function. These switches are either in the "tripped" or "not tripped" condition, depending on the sensed pressure relative to the trip setpoint. There is no read-out indication provided that can be used to compare these instruments to the indications of other similar instruments

TECHNICAL CHANGES - LESS RESTRICTIVE

L.10 (cont'd) measuring the same parameter. The CHANNEL CHECK requirement is currently satisfied by verifying each of the pressure switches are "not tripped" as indicated by the associated annunciators not being in alarm. This CHANNEL CHECK methodology provides a comparison of the "tripped" and "not tripped" status of the pressure switches, but does not provide indication of the overall condition of the pressure switch over and above that provided by the annunciators. Thus, the verification of this status on a 12 hour periodicity does not provide information that is not constantly available to the plant Operations staff through the absence of an annunciator. | B

L.11 A proposed Note is being added to the APRM heat balance calibration (SR 3.3.1.1.2) that states the Surveillance is not required to be performed until 12 hours after THERMAL POWER $\geq$ 25% RTP. This is allowed because it is difficult to accurately determine core THERMAL POWER from a heat balance < 25% RTP. At low power levels, a high degree of accuracy is unnecessary because of the large inherent margin to thermal limits (MCPR and APLHGR). This Frequency is consistent with the BWR Standard Technical Specifications, NUREG-1434.

TECHNICAL CHANGES - MORE RESTRICTIVE

M.3 (cont'd) (Required Action C.2.1.2). These new requirements are being added to offset the deletion of the RSCS (see Discussion of Changes for CTS: 3/4.1.4.2, in Section 3.1) and ensure the RWM is reliable. These changes are additional restrictions on plant operation.

M.4 An additional Surveillance has been added for the RWM. Proposed SR 3.3.2.1.6 ensures the automatic enabling point of the RWM is calibrated properly. This is an additional restriction on plant operation.

M.5 This requirement has been rewritten as a Note, and a finite 1 hour time to perform the Surveillance after entering the RWM applicability has been added. Currently, no Completion Time is specified. This is an additional restriction on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 Trip setpoints are an operational detail that is not directly related to the OPERABILITY of the instrumentation. These details are proposed to be relocated to plant procedures. The Allowable Value is the required limitation for the parameter and this value is retained in the Technical Specifications. Changes to the relocated setpoints in procedures will be controlled by the provisions of 10 CFR 50.59.

LA.2 Current Note (a) to Table 3.3.6-1 states that the RBM shall be automatically bypassed when a peripheral control rod is selected or the reference APRM channel indicates less than 30% of RATED THERMAL POWER. These system design details are proposed to be relocated to the FSAR. These are design details that are not necessary to be included in the Technical Specifications to ensure the OPERABILITY of the RBM instrumentation since OPERABILITY requirements are adequately addressed in Specification 3.3.2.1. In addition, when a peripheral control rod is selected, RBM is automatically bypassed and can not generate a rod block. Therefore, the Applicabilities for the RBM Functions also specify $\geq$ 30% RTP and no peripheral control rod selected, consistent with the design and current Note (a). Changes to the FSAR will be controlled by the provisions of 10 CFR 50.59. (B)

LA.3 Details of the methods for performing Surveillances are proposed to be relocated to the Bases. These requirements proposed to be relocated are procedural details that are not necessary for assuring control rod block instrumentation OPERABILITY. The Surveillance Requirements of Specification 3.3.2.1 provide adequate assurance the control rod block instrumentation are maintained OPERABLE. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

"Specific"

L.1 These Surveillance tests are required to be performed periodically while in the applicable MODES. The required periodic Frequency has been determined to be sufficient verification that the RBMs are properly functioning. Performing a reactor startup does not impact the ability of the monitors to perform their required function. Therefore, an additional surveillance required to be performed "prior to a reactor startup" is an extraneous and unnecessary performance of a surveillance.

L.2 The RWM low power setpoint has been reduced from 20% RTP to 10% RTP. Amendment 17 to NEDE-24011-P-A (GESTAR-II) justified reduction of the power level at which the RWM is bypassed from its current value of 20% RTP to 10% RTP. The justification was based on the fact that the analytical basis for this bypass power level is 10% RTP. The NRC Safety Evaluation Report (SER) for Amendment 17, "Acceptance for Referencing the Licensing Topical Report NEDE-24011-P-A, General Electric Standard Application for Reactor Fuel, Revision 8, Amendment 17," December 27, 1988, states that the 20% RTP Technical Specification limit was previously required as an extreme bound, because of uncertainties in the Rod Drop Accident (RDA) analyses available in the early 1970's. It is now recognized that if core power level exceeds 10% RTP, no control rod pattern can generate rod worths such that the fuel enthalpy would exceed the 280 cal/gm fuel enthalpy limit during the worst RDA. For this reason, this reduction in the bypass power level analytical limit value (Technical Specification limit) was approved by the NRC through its approval of Amendment 17 as described in the SER. The Supply System has reviewed Amendment 17 to NEDE-24011-P-A and the NRC SER, and finds the results and conclusions applicable to WNP-2.

L.3 The Frequency of these Surveillances have been changed. Currently, the Surveillances must be performed every reactor startup and shutdown, regardless of the actual frequency of these events. The new Frequency will only require the Surveillances to be performed every 92 days. The RWM is a reliable system, as shown by both a review of maintenance history and by the successful completion of the startup Surveillance during the last 6 startups. In addition, other similar rod block functions have a 92 day CHANNEL FUNCTIONAL TEST. (B)

L.4 Current ACTION a.1 and Surveillance Requirement 4.1.4.3.b have been deleted. Since a LIMITING CONTROL ROD PATTERN is defined as operating on a power distribution limit (such as APLHGR or MCPR), the condition is extremely unlikely. The status of power distribution limits does not affect the OPERABILITY of the RBM and therefore, no additional requirements on the RBM System are required (e.g., that it be tripped within one hour with a channel inoperable while on a LIMITING CONTROL ROD PATTERN). Adequate requirements on power distribution limits are specified in the

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

LB.1 A Note has been added to the Surveillance Requirements to allow a channel to be inoperable during a Surveillance without requiring the associated Conditions and Required Actions to be taken. The time of this allowance is limited to 6 hours, and is only allowed provided feedwater and main turbine high water level trip capability is maintained. This short time has been shown to provide an acceptable assurance of OPERABILITY in accordance with a previously conducted reliability analysis (GENE-770-06-1-A, December 1992). As required by the NRC Safety Evaluation Report accepting this generic reliability analysis (dated July 21, 1992), WNP-2 has confirmed that the logic design of the instrumentation is bounded by that analyzed in the reliability analysis and the conclusions of the analysis are applicable to the WNP-2 design. (B)

LB.2 The CHANNEL FUNCTIONAL TEST Frequency is extended to once every 92 days. The Frequency has been shown to provide an acceptable assurance of OPERABILITY in accordance with a previously conducted reliability analysis (GENE-770-06-1-A, December 1992). As required by the NRC Safety Evaluation Report accepting this generic reliability analysis (dated July 21, 1992), WNP-2 has confirmed that the logic design of the instrumentation is bounded by that analyzed in the reliability analysis and the conclusions of the analysis are applicable to the WNP-2 design. In addition, WNP-2 has confirmed that the instrument drift due to the extended Surveillance Frequency is already properly accounted for in the setpoint calculation methodology. (B) (B)

LD.1 The Frequency for performing the LOGIC SYSTEM FUNCTIONAL TEST of current Surveillance 4.3.9.2 (proposed SR 3.3.2.2.4) has been extended from 18 months to 24 months to facilitate a change to the WNP-2 maintenance cycle from 12 months to 24 months. The current conditions in the northwest require that WNP-2 shut down each spring for an annual maintenance and refueling outage. Currently, most of the current Surveillances that are required to be performed on an 18 month interval are performed annually because they must be performed while the plant is shut down. This has resulted in increased testing, with a resultant increase in cost and personnel exposure, with no comparable increase in reliability or safety. This change is being proposed to support limiting the amount of surveillance testing that must be performed each maintenance and refueling outage. The proposed change will allow this Surveillance to extend the Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2). This proposed change was evaluated in accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991.

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd) Reviews of historical maintenance and surveillance data have shown that this test normally passes the Surveillance at the current Frequency. An evaluation has been performed using this data, and it has been determined that the effect on safety due to the extended Surveillance Frequency will be small. In addition, the proposed 24 month Surveillance Frequency, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) does not invalidate any assumptions in the plant licensing basis.

LE.1 The Frequency for performing the CHANNEL CALIBRATION Surveillance of current Surveillance 4.3.9.1 and Table 4.3.9.1-1 (proposed SR 3.3.2.2.3) has been extended from 18 months to 24 months to facilitate a change to the WNP-2 maintenance cycle from 12 months to 24 months. The current conditions in the northwest require that WNP-2 shut down each spring for an annual maintenance and refueling outage. Consequently, most of the current Surveillances that are required to be performed on an 18 month interval are performed annually since they must be performed while the plant is shut down. This has resulted in increased testing, with a resultant increase in cost and personnel exposure, with no comparable increase in reliability or safety. This change is being proposed to support limiting the amount of surveillance testing that must be performed each maintenance and refueling outage. The proposed change will allow this Surveillance to extend the Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2). The CHANNEL CALIBRATION Surveillance will continue to be performed in the same manner as it has been in that no modifications to test methodologies or station equipment have been included in this request. Equipment required to mitigate the consequences of an accident will not be affected, except that the frequency of calibrating the instrumentation will be extended to accommodate a 24 month maintenance cycle (i.e., no setpoint changes are necessary). The scope of this request is being limited to those instruments which are calibrated during the annual refueling outage, because the Surveillance is performed during a plant shutdown.

Surveillance 4.3.9.1 and Table 4.3.9.1-1 currently requires the CHANNEL CALIBRATION to be performed once per 18 months. The CHANNEL CALIBRATION Surveillance is performed to ensure that at a previously evaluated setpoint actuation takes place to provide the required safety function. By increasing the maintenance cycle from 12 months to 24 months, the time interval for the CHANNEL CALIBRATION Surveillance for this instrumentation will be increased. However, as currently required by WNP-2 TS, CHANNEL FUNCTIONAL TESTS are performed during the operating cycle more

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) frequently than the CHANNEL CALIBRATION Surveillance. These CHANNEL FUNCTIONAL TESTS detect failures of the instrumentation channels, except for field devices, such as transmitters, that are only tested once every 12 or 18 months. Gross instrumentation failures are detected by alarms or by a comparison with redundant and independent indications. Instrumentation purchased for these functions are highly reliable and meet the design criteria of safety related equipment. The instrumentation is designed with redundant and independent channels which provide means to verify proper instrumentation performance during operation, and adequate redundancy to ensure a high confidence of system performance even with the failure of a single component. Based on this discussion and the drift analysis performed, the Supply System has concluded that the impact on instrumentation was small, if any, as a result of this change.

NRC Generic Letter 91-04 (GL91-04) provided guidance to licensees on the type of analysis and information required to justify a change to the surveillance interval for instrument calibrations. Seven specific actions were delineated in GL91-04 and are repeated below with the applicable response. This discussion is meant as a generic discussion to provide insight into the methodology the Supply System used to evaluate the affects of an increased surveillance interval on instrument drift. The results support the conclusion that instrument drift is not a significant factor in increasing the surveillance interval.

1. Confirm that instrument drift as determined by as-found and as-left calibration data from surveillance and maintenance records has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

   The effect of increased calibration intervals on the TS instrumentation for WNP-2 to accommodate a 24 month maintenance cycle has been determined. Two issues associated with the instrumentation have been evaluated: a) instrument availability based on consideration of historical instrument test failures and b) instrument drift.

   a) Instrument Availability with Consideration to Historical Instrument Test Failures

      A search was performed of the equipment history of the line items covered by this request. This search was conducted to identify equipment problems since 1990. Each of the problems were reviewed to determine the cause. The purpose of this evaluation was to determine the impact that an increase in the surveillance interval has on instrument availability. This review identified that instrument failure rates

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd)

The methodology used to determine the magnitude of instrument drift provides a high degree of probability and a high degree of confidence for a bounding calibration interval of 30 months for each instrument type is included in the analysis. The specific instrument applications are contained in the appropriate section of the ITS submittal.

4. Confirm that a comparison of the projected instrument drift errors has been made with the values of drift used in the setpoint analysis. If this results in revised setpoints to accommodate larger drift errors, provide proposed TS changes to update trip setpoints. If the drift errors result in revised safety analysis to support existing setpoints, provide a summary of the updated analysis conclusions to confirm that safety limits and safety analysis assumptions are not exceeded.

The 30 month projected drift number was compared to the present allowance for the instrument application. The drift for each instrument type fell within the present bounds of the acceptance criteria. Data for intervals as large as 650 days were analyzed showing drift remained within the current acceptance criteria, These analyses were done in accordance with ISA Standard, SP67.04-1982, "Setpoints for Nuclear Safety-Related Instruments used in Nuclear Power Plants," which was approved for use by the NRC in RG 1.105, Revision 2, February 1986. To extend to a 30 month surveillance interval, justification of either acceptable projected drift or justification from the instrument manufacturer was used. In no case was the setpoint of an instrument changed to accommodate a drift error larger than previously evaluated. (C)

5. Confirm that the projected instrument errors caused by drift are acceptable for control of plant parameters to effect a safe shutdown with associated instrumentation.

As discussed in response to item 4 above, the justification for extending the surveillance interval of an instrument was an instrument drift calculation within the existing design basis with the extended time interval. Additional factors evaluated included more frequent testing or a manufacturer recommendation. In no case was the existing safe shutdown analysis changed to accommodate a larger drift error. (C)

6. Confirm that all conditions and assumptions of the setpoint and safety analyses gave been checked and are appropriately reflected in the acceptance criteria of plant surveillance procedures for channel checks, channel functional tests, and channel calibrations.

ADMINISTRATIVE

A.4 (cont'd) is clarified here by adding this note. This change represents a presentation preference only and is, therefore, considered administrative.

A.5 The proposed format for this Specification includes a Condition (ACTION D) that directs entry into the appropriate Conditions referenced in Table 3.3.3.1-1 when two or more channels in the same Function are inoperable and the Completion Time for restoration of all but one required channel has expired (i.e., proposed ACTION C). The ACTION has been added since all Functions have the same ACTIONS when the required channels are not restored. This change represents a presentation preference only and is, therefore, considered administrative. (B) (B)

A.6 The technical content of this requirement is being moved to Chapter 5 of the proposed Technical Specifications in accordance with the format of the BWR Standard Technical Specifications, NUREG-1434. Any technical changes to this requirement are addressed in the Discussion of Changes for ITS: 5.6. An ACTION is added (proposed ACTION F) to clearly state to initiate action in accordance with Specification 5.6.7. Since this is a presentation preference that maintains current requirements, this change is considered administrative.

RELOCATED SPECIFICATIONS

R.1 These instruments are not credited as Category 1 or Type A variables. This evaluation was summarized in the NRC SER, dated 3/23/88, that accepted the WNP-2 categorization of these instruments. However, for the neutron flux monitor, which was credited as a Type A variable, WNP-2 will reclassify in accordance with NEDO-31558, since the role of the WNP-2 neutron flux monitors is not different than that evaluated in NEDO-31558. Further, the loss of these instruments is a non-significant risk contributor to core damage frequency and offsite release. Therefore, the requirements specified for these Functions did not satisfy the NRC Policy Statement Technical Specification screening criteria as documented in the Application of Selection Criteria to the WNP-2 Technical Specifications and have been relocated to plant documents controlled in accordance with 10 CFR 50.59. (L)

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 Requirements for an additional PAM Function for ECCS Pump Room Flood Level is incorporated. The Function is included in accordance with NUREG-1434 guidelines to include all Type A and Category 1 PAMs.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

M.2 Currently no ACTIONS are required with one Primary Containment Gross Radiation Monitor inoperable. Proposed ACTIONS A and B are added to provide requirements to restore the channel within 30 days or submit a special report, consistent with ACTIONS for other PAM instruments. This is an additional restriction on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The use of alternate methods of monitoring are proposed to be relocated to the Bases. These details are not necessary to be included in Technical Specifications to ensure actions are taken to initiate the preplanned alternate method of monitoring since Condition F requires action to be immediately initiated in accordance with Specification 5.6.7. Specification 5.6.7 requires a report to be submitted to the NRC within the following 14 days and that the report outline the preplanned alternate method of monitoring. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LA.2 Details of the method for performing the Surveillance (in this case the CHANNEL CALIBRATION of the primary containment gross radiation monitors) are proposed to be relocated to the Bases. These requirements proposed to be relocated are procedural details that are not necessary for assuring the OPERABILITY of the primary containment gross radiation monitors. The Surveillance Requirements of Specification 3.3.3.1 provide adequate assurance the primary containment gross radiation monitors are maintained OPERABLE. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LE.1 The Frequency for performing the CHANNEL CALIBRATION Surveillance of current Surveillance 4.3.7.5 and Table 4.3.7.5-1 for Instruments 3 and 28 (proposed SR 3.3.3.1.4 for Functions 3 and 6) has been extended from 18 months to 24 months to facilitate a change to the WNP-2 maintenance cycle from 12 months to 24 months. The current conditions in the northwest require that WNP-2 shut down each spring for an annual maintenance and refueling outage. Consequently, most of the current Surveillances that are required to be performed on an 18 month interval are performed annually since they must be performed while the plant is shut down. This has resulted in increased testing, with a resultant increase in cost and personnel exposure, with no comparable increase in reliability or safety. This change is being proposed to support limiting the amount of surveillance testing that must be performed each maintenance and refueling outage. The proposed change will allow this Surveillance to extend the Surveillance Frequency from

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2). The CHANNEL CALIBRATION Surveillance will continue to be performed in the same manner as it has been in that no modifications to test methodologies or station equipment have been included in this request. Equipmentrequired to mitigate the consequences of an accident will not be affected, except that the frequency of calibrating the instrumentation will be extended to accommodate a 24 month maintenance cycle (i.e., no setpoint changes are necessary). The scope of this request is being limited to those instruments which are calibrated during the annual refueling outage, because the Surveillance is performed during a plant shutdown.

Surveillance 4.3.7.5 and Table 4.3.7.5-1 currently requires the CHANNEL CALIBRATION to be performed once per 18 months for Instruments 3 and 28. The CHANNEL CALIBRATION Surveillance is performed to ensure that the indication is accurate to provide the required safety function. By increasing the maintenance cycle from 12 months to 24 months, the time interval for the CHANNEL CALIBRATION Surveillance for this instrumentation will be increased. However, as currently required by WNP-2 TS, CHANNEL CHECKS are performed during the operating cycle more frequently than the CHANNEL CALIBRATION Surveillance. Gross instrumentation failures are detected by alarms or by a comparison with redundant and independent indications. Instrumentation purchased for these functions are highly reliable and meet the design criteria of safety related equipment. The instrumentation is designed with redundant and independent channels which provide means to verify proper instrumentation performance during operation, and adequate redundancy to ensure a high confidence of system performance even with the failure of a single component. Based on this discussion and the drift analysis performed, the Supply System has concluded that the impact on instrumentation was small, if any, as a result of this change. 1(B)

NRC Generic Letter 91-04 (GL91-04) provided guidance to licensees on the type of analysis and information required to justify a change to the surveillance interval for instrument calibrations. Seven specific actions were delineated in GL91-04 and are repeated below with the applicable response. This discussion is meant as a generic discussion to provide insight into the methodology the Supply System used to evaluate the affects of an increased surveillance interval on instrument drift. The results support the conclusion that instrument drift is not a significant factor in increasing the surveillance interval.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd)

1. Confirm that instrument drift as determined by as-found and as-left calibration data from surveillance and maintenance records has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

   The effect of increased calibration intervals on the TS instrumentation for WNP-2 to accommodate a 24 month maintenance cycle has been determined. Two issues associated with the instrumentation have been evaluated: a) instrument availability based on consideration of historical instrument test failures and b) instrument drift.

   a) Instrument Availability with Consideration to Historical Instrument Test Failures

      A search was performed of the equipment history of the line items covered by this request. This search was conducted to identify equipment problems since 1990. Each of the problems were reviewed to determine the cause. The purpose of this evaluation was to determine the impact that an increase in the surveillance interval has on instrument availability. This review identified that instrument failure rates detected by the annual CHANNEL CALIBRATION Surveillance were insignificant. Because of system redundancy and the very small number of failures which are detected only during the annual CHANNEL CALIBRATION, the change in the Surveillance Frequency will have a small impact, if any, on system availability.

   b. Instrument Drift

      The applicable surveillance tests were reviewed, and historical instrument drift related data was obtained. This data included as-left values, as-found values and required limits identified during each instrument calibration. Based on this data a drift analysis (see item 2 below) was performed as described in EPRI TR-103335, "Guidelines for I&C Calibration Extension Reduction Programs." The failure history in combination with the drift study demonstrates that except in rare occasions instrument drift has not exceeded the current allowable limits.

2. Confirm that the values of drift for each instrument type (make, model, and range) and application have been determined with a high probability and a high degree of confidence. Provide a summary of the methodology and assumptions used to determine the rate of instrument drift with time based upon historical plant calibration.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd)

The Supply System developed a methodology to evaluate instrument drift that employed standard statistical methods. The methods are consistent with industry practice and guidance in EPRI TR-103335. The approach to characterizing instrument drift and establishing the presence of time dependent drift (or lack thereof) was as follows:

Individual drift observations were determined by means of as-found minus as-left data; these observations were evaluated and sample statistics were calculated; the sample statistics were used to establish predicted limits for drift measurements (the limits were calculated using 95/95 tolerance intervals); to ensure non-conservative assumptions were not made, a verification of the assumption of normality used in the tolerance interval calculation was required (the population must be normally distributed or at least bounded by the normal distribution to apply conventional tolerance interval methods); the time dependency of the drift was then evaluated through data inspection (scatter plots) and regression analyses (the slope estimates, R^2, and F statistics were employed to assess the presence of time dependency). It should be noted that the estimates of drift were conservative because they include not only the true drift but also the combined effect of several other measurement uncertainties.

The result of the calculation showed that the instrumentation evaluated exhibit the performance characteristics expected and the result are consistent with industry experience. It was found that the predicted drift can be expected to be bounded by the tolerance interval. This means that with 95% confidence, it can be expected that 95% of the population should be contained within the tolerance interval. The magnitude of this interval is as expected and is consistent with several other calculations examined (with comparable sample sizes). It should be noted that the tolerance interval width increases with increasing span. Again, this in consistent with industry experience.

The sample observations were analyzed to verify the assumption of normality, but did not always pass the test at 0.05 significance. The failure was caused by a decreased dispersion (i.e., less variability) relative to a normal distribution. The tests did show that the high density clustered about zero allowed the conclusion that the population distribution could be considered to be bounded by the normal distribution. Therefore, application of tolerance intervals based on the assumption of normality is somewhat conservative.

No time dependency with respect to drift was evident. Scatter plots for data inspection and simple linear

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd)

regression for a linear relationship were employed. No visible trends were seen nor were any of the regression statistics significant. Moreover, the estimated slopes differed negligibly from zero. Therefore, it is concluded that no time dependent drift concerns should preclude the extension of the CHANNEL CALIBRATION Surveillance Frequency from 18 months to 24 months.

3. Confirm that the magnitude of instrument drift has been determined with a high probability and a high degree of confidence for a bounding calibration interval of 30 months for each instrument type (make, model number and range) and application that performs a safety function. Provide a list of the channels by TS section that identifies these instrument application.

   The methodology used to determine the magnitude of instrument drift provides a high degree of probability and a high degree of confidence for a bounding calibration interval of 30 months for each instrument type is included in the analysis. The specific instrument applications are contained in the appropriate section of the ITS submittal.

4. Confirm that a comparison of the projected instrument drift errors has been made with the values of drift used in the setpoint analysis. If this results in revised setpoints to accommodate larger drift errors, provide proposed TS changes to update trip setpoints. If the drift errors result in revised safety analysis to support existing setpoints, provide a summary of the updated analysis conclusions to confirm that safety limits and safety analysis assumptions are not exceeded.

   The 30 month projected drift number was compared to the present allowance for the instrument application. The drift for each instrument type fell within the present bounds of the acceptance criteria. Data for intervals as large as 650 days were analyzed showing drift remained within the current acceptance criteria, These analyses were done in accordance with ISA Standard, SP67.04-1982, "Setpoints for Nuclear Safety-Related Instruments used in Nuclear Power Plants," which was approved for use by the NRC in RG 1.105, Revision 2, February 1986. To extend to a 30 month surveillance interval, justification of either acceptable projected drift or justification from the instrument manufacturer was used. In no case was the setpoint of an instrument changed to accommodate a drift error larger than previously evaluated. |B |A

5. Confirm that the projected instrument errors caused by drift are acceptable for control of plant parameters to effect a safe shutdown with associated instrumentation.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) As discussed in response to item 4 above, the justification for extending the surveillance interval of an instrument was an instrument drift calculation within the existing design basis with the extended time interval. Additional factors evaluated included more frequent testing or a manufacturer recommendation. In no case was the existing safe shutdown analysis changed to accommodate a larger drift error. (B)

6. Confirm that all conditions and assumptions of the setpoint and safety analyses gave been checked and are appropriately reflected in the acceptance criteria of plant surveillance procedures for channel checks, channel functional tests, and channel calibrations.

The Supply System has not changed any of the setpoint or acceptance criteria of the present CHANNEL CALIBRATION Surveillances, therefore, there is no cause to reverify the criteria used to establish the acceptance criteria in the surveillance test.

7. Provide a summary description of the program for monitoring and assessing the effects of increased calibration surveillance intervals on instrument drift and its effects on safety.

For the suppression chamber water level instrumentation, the instrumentation program at WNP-2 includes the verification that instruments are reading within specified tolerances during CHANNEL CHECKS. If not, actions must be taken to resolve the discrepancy. This could involve recalibrating the instrumentation or initiating a Problem Evaluation Report (PER). For the primary containment gross radiation monitors, the instrumentation program at WNP-2 includes verification that instruments are reading within specified tolerances during CHANNEL CHECKS. If not, actions must be taken to resolve the discrepancy (e.g., recalibration). In addition to the monthly CHANNEL CHECK that will provide indication of excessive instrument drift, the equipment has an automatic self-checking feature that alarms in the control room if problems are indicated. Excessive drift or instrument failure will lead to the initiation of a Problem Evaluation Report (PER). The instrumentation is required to provide gross indication only (an accuracy of 20%) of post accident radiation levels so the effects of the increased interval on safety are minimal. The review of the PER will require, based on the results of that review, that a decision on the appropriate calibration interval be made. Such a decision will consider such things as shortening the

INSTRUMENTATION

REMOTE SHUTDOWN MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

LCO 3.3.3.2

3.3.7.4 The remote shutdown monitoring instrumentation channels shown in Table 3.3.7.4-1 shall be OPERABLE with readouts displayed external to the control room. LA.1

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION: Proposed Note 2 to ACTIONS A.1 LA.1

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

b. The provisions of Specification 3.0.4 are not applicable.

NOTE 1 to ACTIONS

L.2

Proposed Note to Surveillance Requirements

SURVEILLANCE REQUIREMENTS

SRs 3.3.3.2.1, 3.3.3.2.2, and 3.3.3.2.3

4.3.7.4 Each of the above required remote shutdown monitoring instrumentation channels shall be demonstrated OPERABLE by performance of the CHANNEL CHECK, and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.7.4-1. LA.1

, for each required instrumentation channel that is normally energized, A.2

Proposed SR 3.3.3.2.4 M.1

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TABLE 4.3.7.4-1

REMOTE SHUTDOWN MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	SR 3.3.3.2.1 CHANNEL CHECK	SR 3.3.3.2.2 and SR 3.3.3.2.3 CHANNEL CALIBRATION
1. Reactor Vessel Pressure	M	R-2
2. Reactor Vessel Water Level	M	R-2
3. Suppression Chamber Air Temperature	M	R-2
4. Suppression Chamber Water Level	M	R-2 (3)
5. Suppression Chamber Water Temperature	M	R-2
6. Service Water Pump B Discharge Pressure	M	R-2
7. Drywell Pressure, Low Range	M	R-2
8. Drywell Pressure, High Range	M	R-2
9. Upper Drywell Temperature	M	R-2
10. RHR System Flow	M	R-2
11. Spray Pond B Level	M	R-2
12. Spray Pond B Temperature	M	R-2
13. RCIC System Flow	M	R-2
14. RCIC Turbine Speed	M	R-2

LA.1 B

(3) 24 months LE.1

A.2

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Specification 3.3.3.2

DISCUSSION OF CHANGES
ITS: 3.3.3.2 - REMOTE SHUTDOWN SYSTEM

ADMINISTRATIVE

A.1 These proposed changes provide more explicit instructions for proper application of the ACTIONS for Technical Specification compliance. In conjunction with the proposed Specification 1.3, "Completion Times," the ACTIONS Note ("Separate Condition entry is allowed for each....") and the wording for ACTION A ("one or more required Functions") provides direction consistent with the intent of the existing ACTION for an inoperable remote shutdown instrumentation channel. Since this change only provides more explicit direction of the current interpretation of the existing specifications, this change is considered administrative.

A.2 Some instrumentation channels (current Table 4.3.7.4-1, Instruments 1, 2, 7, 10, 13, and 14) are deenergized during normal operation. No specific acceptance criteria would apply to the CHANNEL CHECK (since the instruments would not be indicating). Therefore, this Surveillance Requirement is modified to exclude the CHANNEL CHECK requirement on these deenergized channels. This change is considered administrative (since the channels are normally deenergized and any CHANNEL CHECK requirement would be essentially equivalent to no requirement). In addition, energizing these instrument channels requires operation of a transfer switch, which takes control on the instrument (and any associated controls) from the control room and shifts it to the remote shutdown panel. When this is performed, the instruments and associated controls in the control room are deenergized and no indication and control are available to control room operators.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 A new Surveillance has been added (SR 3.3.3.2.4) to verify each required control circuit and transfer switch is capable of performing the intended function once per 24 months. This is an additional restriction on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 Details relating to system design and operation (e.g., specific instrument listings) are unnecessary in the LCO and are proposed to be relocated to the Licensee Controlled Specifications Manual. Specification 3.3.3.2 requires the Remote Shutdown System Functions to be OPERABLE. These requirements are adequate for ensuring each required Remote Shutdown System Function is maintained OPERABLE. The Bases also identifies that the

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.1 (cont'd) instruments are listed in the Licensee Controlled Specifications Manual. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications. Changes to the relocated requirements in the Licensee Controlled Specifications Manual will be controlled by the provisions of 10 CFR 50.59.

LE.1 The Frequency for performing the CHANNEL CALIBRATION Surveillance of current Surveillance 4.3.7.4 and Table 4.3.7.4-1 for Instrument 4 (proposed SR 3.3.3.2.3) has been extended from 18 months to 24 months to facilitate a change to the WNP-2 maintenance cycle from 12 months to 24 months. The current conditions in the northwest require that WNP-2 shut down each spring for an annual maintenance and refueling outage. Consequently, most of the current Surveillances that are required to be performed on an 18 month interval are performed annually since they must be performed while the plant is shut down. This has resulted in increased testing, with a resultant increase in cost and personnel exposure, with no comparable increase in reliability or safety. This change is being proposed to support limiting the amount of surveillance testing that must be performed each maintenance and refueling outage. The proposed change will allow this Surveillance to extend the Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2). The CHANNEL CALIBRATION Surveillance will continue to be performed in the same manner as it has been in that no modifications to test methodologies or station equipment have been included in this request. Equipment required to mitigate the consequences of an accident will not be affected, except that the frequency of calibrating the instrumentation will be extended to accommodate a 24 month maintenance cycle (i.e., no setpoint changes are necessary). The scope of this request is being limited to those instruments which are calibrated during the annual refueling outage, because the Surveillance is performed during a plant shutdown. (B)

Surveillance 4.3.7.4 and Table 4.3.7.4-1 currently requires the CHANNEL CALIBRATION to be performed once per 18 months for Instrument 4. The CHANNEL CALIBRATION Surveillance is performed to ensure that the indication is accurate to provide the required safety function. By increasing the maintenance cycle from 12 months to 24 months, the time interval for the CHANNEL CALIBRATION Surveillance for this instrumentation will be increased. However, as currently required by WNP-2 TS, CHANNEL CHECKS are performed during the operating cycle more frequently than the CHANNEL CALIBRATION Surveillance. Gross instrumentation failures are

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) detected by alarms or by a comparison with redundant and independent indications. Instrumentation purchased for these functions are highly reliable and meet the design criteria of safety related equipment. The instrumentation is designed with redundant and independent channels which provide means to verify proper instrumentation performance during operation, and adequate redundancy to ensure a high confidence of system performance even with the failure of a single component. Based on this discussion and the drift analysis performed, the Supply System has concluded that the impact on instrumentation was small, if any, as a result of this change.

NRC Generic Letter 91-04 (GL91-04) provided guidance to licensees on the type of analysis and information required to justify a change to the surveillance interval for instrument calibrations. Seven specific actions were delineated in GL91-04 and are repeated below with the applicable response. This discussion is meant as a generic discussion to provide insight into the methodology the Supply System used to evaluate the affects of an increased surveillance interval on instrument drift. The results support the conclusion that instrument drift is not a significant factor in increasing the surveillance interval.

1. Confirm that instrument drift as determined by as-found and as-left calibration data from surveillance and maintenance records has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

   The effect of increased calibration intervals on the TS instrumentation for WNP-2 to accommodate a 24 month maintenance cycle has been determined. Two issues associated with the instrumentation have been evaluated: a) instrument availability based on consideration of historical instrument test failures and b) instrument drift.

   a) Instrument Availability with Consideration to Historical Instrument Test Failures

      A search was performed of the equipment history of the line items covered by this request. This search was conducted to identify equipment problems since 1990. Each of the problems were reviewed to determine the cause. The purpose of this evaluation was to determine the impact that an increase in the surveillance interval has on instrument availability. This review identified that instrument failure rates detected by the annual CHANNEL CALIBRATION Surveillance were insignificant. Because of system redundancy and the very small number of failures which are detected only during the annual CHANNEL

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd)

CALIBRATION, the change in the Surveillance Frequency will have a small impact, if any, on system availability.

b. Instrument Drift

The applicable surveillance tests were reviewed, and historical instrument drift related data was obtained. This data included as-left values, as-found values and required limits identified during each instrument calibration. Based on this data a drift analysis (see item 2 below) was performed as described in EPRI TR-103335, "Guidelines for I&C Calibration Extension Reduction Programs." The failure history in combination with the drift study demonstrates that except in rare occasions instrument drift has not exceeded the current allowable limits.

2. Confirm that the values of drift for each instrument type (make, model, and range) and application have been determined with a high probability and a high degree of confidence. Provide a summary of the methodology and assumptions used to determine the rate of instrument drift with time based upon historical plant calibration.

The Supply System developed a methodology to evaluate instrument drift that employed standard statistical methods. The methods are consistent with industry practice and guidance in EPRI TR-103335. The approach to characterizing instrument drift and establishing the presence of time dependent drift (or lack thereof) was as follows:

Individual drift observations were determined by means of as-found minus as-left data; these observations were evaluated and sample statistics were calculated; the sample statistics were used to establish predicted limits for drift measurements (the limits were calculated using 95/95 tolerance intervals); to ensure non-conservative assumptions were not made, a verification of the assumption of normality used in the tolerance interval calculation was required (the population must be normally distributed or at least bounded by the normal distribution to apply conventional tolerance interval methods); the time dependency of the drift was then evaluated through data inspection (scatter plots) and regression analyses (the slope estimates, R^2, and F statistics were employed to assess the presence of time dependency). It should be noted that the estimates of drift were conservative because they include not only the true drift but also the combined effect of several other measurement uncertainties.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd)

The result of the calculation showed that the instrumentation evaluated exhibit the performance characteristics expected and the result are consistent with industry experience. It was found that the predicted drift can be expected to be bounded by the tolerance interval. This means that with 95% confidence, it can be expected that 95% of the population should be contained within the tolerance interval. The magnitude of this interval is as expected and is consistent with several other calculations examined (with comparable sample sizes). It should be noted that the tolerance interval width increases with increasing span. Again, this in consistent with industry experience.

The sample observations were analyzed to verify the assumption of normality, but did not always pass the test at 0.05 significance. The failure was caused by a decreased dispersion (i.e., less variability) relative to a normal distribution. The tests did show that the high density clustered about zero allowed the conclusion that the population distribution could be considered to be bounded by the normal distribution. Therefore, application of tolerance intervals based on the assumption of normality is somewhat conservative.

No time dependency with respect to drift was evident. Scatter plots for data inspection and simple linear regression for a linear relationship were employed. No visible trends were seen nor were any of the regression statistics significant. Moreover, the estimated slopes differed negligibly from zero. Therefore, it is concluded that no time dependent drift concerns should preclude the extension of the CHANNEL CALIBRATION Surveillance Frequency from 18 months to 24 months. (A)

3. Confirm that the magnitude of instrument drift has been determined with a high probability and a high degree of confidence for a bounding calibration interval of 30 months for each instrument type (make, model number and range) and application that performs a safety function. Provide a list of the channels by TS section that identifies these instrument application.

The methodology used to determine the magnitude of instrument drift provides a high degree of probability and a high degree of confidence for a bounding calibration interval of 30 months for each instrument type is included in the analysis. The specific instrument applications are contained in the appropriate section of the ITS submittal.

4. Confirm that a comparison of the projected instrument drift errors has been made with the values of drift used in the setpoint analysis. If this results in revised setpoints to

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd)

accommodate larger drift errors, provide proposed TS changes to update trip setpoints. If the drift errors result in revised safety analysis to support existing setpoints, provide a summary of the updated analysis conclusions to confirm that safety limits and safety analysis assumptions are not exceeded.

The 30 month projected drift number was compared to the present allowance for the instrument application. The drift for each instrument type fell within the present bounds of the acceptance criteria. Data for intervals as large as 650 days were analyzed showing drift remained within the current acceptance criteria, These analyses were done in accordance with ISA Standard, SP67.04-1982, "Setpoints for Nuclear Safety-Related Instruments used in Nuclear Power Plants," which was approved for use by the NRC in RG 1.105, Revision 2, February 1986. To extend to a 30 month surveillance interval, justification of either acceptable projected drift or justification from the instrument manufacturer was used. In no case was the setpoint of an instrument changed to accommodate a drift error larger than previously evaluated.

5. Confirm that the projected instrument errors caused by drift are acceptable for control of plant parameters to effect a safe shutdown with associated instrumentation.

As discussed in response to item 4 above, the justification for extending the surveillance interval of an instrument was an instrument drift calculation within the existing design basis with the extended time interval. Additional factors evaluated included more frequent testing or a manufacturer recommendation. In no case was the existing safe shutdown analysis changed to accommodate a larger drift error.

6. Confirm that all conditions and assumptions of the setpoint and safety analyses gave been checked and are appropriately reflected in the acceptance criteria of plant surveillance procedures for channel checks, channel functional tests, and channel calibrations.

The Supply System has not changed any of the setpoint or acceptance criteria of the present CHANNEL CALIBRATION Surveillances, therefore, there is no cause to reverify the criteria used to establish the acceptance criteria in the surveillance test.

7. Provide a summary description of the program for monitoring and assessing the effects of increased calibration surveillance intervals on instrument drift and its effects on safety.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) For the suppression chamber water level instrumentation, the instrumentation program at WNP-2 includes the verification that instruments are reading within specified tolerances during CHANNEL CHECKS. If not, actions must be taken to resolve the discrepancy. This could involve recalibrating the instrumentation or initiating a Problem Evaluation Report (PER). The review of the PER will require, based on the results of that review, that a decision on the appropriate calibration interval be made. Such a decision will consider such things as shortening the surveillance test interval (STI), changing the setpoint of the instrument or leaving the STI at 24 months. Review of the Surveillance results will be performed until such time as we determine that further evaluation is no longer necessary. (B)

"Specific"

L.1 The allowed outage time (AOT) for inoperable remote shutdown system instrumentation and controls is extended to 30 days. The system is not required to respond to any mechanistic design basis accident evaluated in the safety analysis, but is provided to comply with GDC-19 design criteria. The Specification is retained only as a significant contributor to risk reduction, and extending the AOT does not have a significant impact on that contribution.

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

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 Trip setpoints are an operational detail that is not directly related to the OPERABILITY of the instrumentation. These details are proposed to be relocated to plant procedures. The Allowable Value is the required limitation for the parameter and this value is retained in the Technical Specifications. Changes to the relocated requirements in procedures will be controlled by the provisions of 10 CFR 50.59.

LA.2 Details of the actual response times are proposed to be relocated to the Licensee Controlled Specification Manual. Testing of the response time is provided by proposed SR 3.3.4.1.5 and SR 3.3.4.1.6 and is an integral part of the OPERABILITY of the instrumentation channels. As such, the requirements of Specification 3.3.4.1 and the associated Surveillance Requirements are adequate to ensure the EOC-RPT instruments are maintained OPERABLE. Changes to the relocated requirements in the Licensee Controlled Specification Manual will be controlled by the provisions of 10 CFR 50.59.

LA.3 Current Note (b) to Table 3.3.4.2-1 states that Turbine Throttle Valve–Closure and the Turbine Governor Valve Fast Closure, Valve Trip System Oil Pressure–Low Functions shall be automatically bypassed when turbine first stage pressure is less than or equal to the pressure equivalent to THERMAL POWER less than 30% of RATED THERMAL POWER. These system design details are proposed to be relocated to the FSAR. These are design details that are not necessary to be included in the Technical Specifications to ensure the OPERABILITY of the EOC-RPT instrumentation since OPERABILITY requirements are adequately addressed in Specification 3.3.4.1. In addition, the Applicabilities for the Turbine Throttle Valve–Closure and the Turbine Governor Valve Fast Closure, Valve Trip System Oil Pressure–Low Functions have been modified to be ≥ 30% RTP, consistent with the design and current Note (b). Changes to the FSAR will be controlled by the provisions of 10 CFR 50.59.

LB.1 The allowed out of service time (AOT) is extended to 72 hours. This AOT has been shown to maintain an acceptable risk in accordance with previously conducted reliability analysis (GENE-770-06-1-A, December 1992). As required by the NRC Safety Evaluation Report accepting this generic reliability analysis (dated July 21, 1992), WNP-2 has confirmed that the logic design of the instrumentation is bounded by that analyzed in the reliability analysis and the conclusions of the analysis are applicable to the WNP-2 design. | (B)

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

LB.2 A time provided to perform Surveillances without requiring the associated Conditions and Required Actions to be taken has been extended from 2 hours to 6 hours. This short time has been shown to provide an acceptable assurance of OPERABILITY in accordance with a previously conducted reliability analysis (GENE-770-06-1-A, December 1992). As required by the NRC Safety Evaluation Report accepting this generic reliability analysis (dated July 21, 1992), WNP-2 has confirmed that the logic design of the instrumentation is bounded by that analyzed in the reliability analysis and the conclusions of the analysis are applicable to the WNP-2 design. (B)

LB.3 The CHANNEL FUNCTIONAL TEST Frequency is extended to once every 92 days. The Frequency has been shown to provide an acceptable assurance of OPERABILITY in accordance with a previously conducted reliability analysis (GENE-770-06-1-A, December 1992). As required by the NRC Safety Evaluation Report accepting this generic reliability analysis (dated July 21, 1992), WNP-2 has confirmed that the logic design of the instrumentation is bounded by that analyzed in the reliability analysis and the conclusions of the analysis are applicable to the WNP-2 design. In addition, WNP-2 has confirmed that the instrument drift due to the extended Surveillance Frequency is already properly accounted for in the setpoint calculation methodology. (B) (B)

LD.1 The Frequencies for performing the LOGIC SYSTEM FUNCTIONAL TEST and EOC-RPT RESPONSE TIME TEST requirements of current Surveillances 4.3.4.2.2 and 4.3.4.2.3 (proposed SRs 3.3.4.1.4 and 3.3.4.1.5) have been extended from 18 months to 24 months to facilitate a change to the WNP-2 maintenance cycle from 12 months to 24 months. The current conditions in the northwest require that WNP-2 shut down each spring for an annual maintenance and refueling outage. Currently, most of the current Surveillances that are required to be performed on an 18 month interval are performed annually because they must be performed while the plant is shut down. This has resulted in increased testing, with a resultant increase in cost and personnel exposure, with no comparable increase in reliability or safety. This change is being proposed to support limiting the amount of surveillance testing that must be performed each maintenance and refueling outage. The proposed change will allow these Surveillances to extend their Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2). This proposed change was evaluated in accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991. Reviews of historical maintenance and surveillance data have shown that these tests normally pass their Surveillances at the current Frequency. An

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd) evaluation has been performed using this data, and it has been determined that the effect on safety due to the extended Surveillance Frequency will be small. In addition, the proposed 24 month Surveillance Frequencies, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) do not invalidate any assumptions in the plant licensing basis.

"Specific"

L.1 An option is provided for one or more inoperable channel(s) to place all inoperable channels in the tripped condition. This conservatively compensates for the inoperable status, restores the single failure capability and provides the required initiation capability of the instrumentation. Therefore, providing this option does not impact safety. However, if this action would result in system actuation, then declaring the system inoperable is the preferred action.

L.2 The ACTIONS for trip system inoperability have been changed to address trip Function (e.g., Turbine Throttle Valve - Closure is a Function) capability. This is consistent with other Specifications that provide appropriate allowed out of service times as long as the actuation capability is maintained. The Function has lost trip capability if an EOC-RPT trip cannot occur from the Function.

L.3 The purpose of this instrumentation is to ensure a MCPR Safety Limit Violation will not occur late in core life due to a turbine trip or generator load rejection. Therefore, the time provided to restore channels to OPERABLE status if both trip systems are affected (current ACTION e), and the time to apply the MCPR EOC-RPT inoperable limit (current ACTIONS d and e), has been extended from 1 hour to 2 hours, consistent with the time provided in current Specification 3.2.3 to restore a MCPR limit. (B)

L.4 An additional Required Action is proposed (Required Action C.1) to allow removal of the associated recirculation pump from service. Since this action accomplishes the functional purpose of the instrumentation and enables continued operation in a previously approved condition, this change does not have a significant effect on safe operation.

INSTRUMENTATION

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

LCO 3.3.4.2

3.3.4.1 The anticipated transient without scram recirculation pump trip (ATWS-RPT) system instrumentation channels shown in Table 3.3.4.1-1 shall be OPERABLE with their trip setpoints set consistent with values shown in the Trip Setpoint column of Table 3.3.4.1-2. LA.1

APPLICABILITY: OPERATIONAL CONDITION 1.

ACTION: A.1

add proposed ACTIONS Note

a. With an ATWS-RPT system instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.4.1-2, declare the channel inoperable until the channel is restored to OPERABLE status with the channel trip setpoint adjusted consistent with the Trip Setpoint value. A.1

Actions A, B, and C

b. With the number of OPERABLE channels per Trip Function less than required by the Minimum OPERABLE Channels per Trip System requirement, verify operability of one trip system within one hour and, restore the inoperable channel(s) to OPERABLE status or place the inoperable channel(s) in the tripped condition* within 14 days. Otherwise be in at least STARTUP within the next 6 hours. L.1

Function L.1

add proposed ACTION B L.1

Action A

Action C

Action A

Action D

add proposed Required Action D.1 L.2

SURVEILLANCE REQUIREMENTS

SRs 3.3.4.2.1, 3.3.4.2.2, and 3.3.4.2.3

4.3.4.1.1. Each ATWS-RPT system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.4.1-1.

SR 3.3.4.2.4

4.3.4.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed at least once per 18 months. A.2

24 L.D.1

*Only applicable if placing the inoperable channel(s) in trip would not result in a recirculation pump trip.

Note to Required Action A.2

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TABLE 3.3.4.1-2

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION SETPOINTS

SR 3.3.4.1.3

TRIP FUNCTION (LCO 3.3.4.2)	TRIP SETPOINT (LA.1)	ALLOWABLE VALUE
a. Reactor Vessel, Water Level - Low Low, Level 2	≥ -50 inches*	≥ -67 (58) inches (LA.1)
b. Reactor Vessel Pressure - High	≤ 1135 psig	≤ (1155) psig (1149 · M.1)

*See Bases Figures B 3/4 3-1. (LA.1)

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Specification 3.3.4.2

DISCUSSION OF CHANGES
ITS: 3.3.4.2 - ATWS-RPT INSTRUMENTATION

ADMINISTRATIVE

A.1 A Note has been added to provide more explicit instructions for proper application of the ACTIONS for Technical Specification compliance. In conjunction with the proposed Specification 1.3, "Completion Times," the ACTIONS Note ("Separate Condition entry is allowed for each....") provides direction consistent with the intent of the existing ACTION for an inoperable ATWS-RPT instrumentation channel. Since this change only provides more explicit direction of the current interpretation of the existing specifications, this change is considered administrative.

A.2 The "simulated automatic operation" is normally conducted with the system functional test. However, for this system the only automatic operation required is opening of the pump trip breakers. Since no separate system functional test is specified, the opening of these breakers is specifically identified and included with the LOGIC SYSTEM FUNCTIONAL TEST. This is only a change in the presentation, therefore this change is considered administrative.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 The Reactor Vessel Pressure-High Function setpoint has been decreased to the proper Allowable Value. The new Allowable Value is based upon the most recent setpoint calculation. This is an additional restriction to plant operation. (B)

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 Trip setpoints are an operational detail that is not directly related to the OPERABILITY of the instrumentation. These details are proposed to be relocated to plant procedures. The Allowable Value is the required limitation for the parameter and this value is retained in the Technical Specifications. Changes to the relocated requirements in procedures will be controlled by the provisions of 10 CFR 50.59.

LB.1 A time provided to perform Surveillances without requiring the associated Conditions and Required Actions to be taken has been extended from 2 hours to 6 hours. This short time has been shown to provide an acceptable assurance of OPERABILITY in accordance with a previously conducted reliability analysis (GENE-770-06-1-A, December 1992). As required by the NRC Safety Evaluation Report accepting this generic reliability analysis (dated July 21, 1992), (B)

TECHNICAL CHANGES - LESS RESTRICTIVE

LB.1 (cont'd) WNP-2 has confirmed that the logic design of the instrumentation is bounded by that analyzed in the reliability analysis and the conclusions of the analysis are applicable to the WNP-2 design. (B)

LB.2 The CHANNEL FUNCTIONAL TEST Frequency is extended to once every 92 days. The Frequency has been shown to provide an acceptable assurance of OPERABILITY in accordance with a previously conducted reliability analysis (GENE-770-06-1-A, December 1992). As required by the NRC Safety Evaluation Report accepting this generic reliability analysis (dated July 21, 1992), WNP-2 has confirmed that the logic design of the instrumentation is bounded by that analyzed in the reliability analysis and the conclusions of the analysis are applicable to the WNP-2 design. In addition, WNP-2 has confirmed that the instrument drift due to the extended Surveillance Frequency is already properly accounted for in the setpoint calculation methodology. (B) (B)

LD.1 The Frequency for performing the LOGIC SYSTEM FUNCTIONAL TEST of current Surveillance 4.3.4.1.2 (proposed SR 3.3.4.2.4) has been extended from 18 months to 24 months to facilitate a change to the WNP-2 maintenance cycle from 12 months to 24 months. The current conditions in the northwest require that WNP-2 shut down each spring for an annual maintenance and refueling outage. Currently, most of the current Surveillances that are required to be performed on an 18 month interval are performed annually because they must be performed while the plant is shut down. This has resulted in increased testing, with a resultant increase in cost and personnel exposure, with no comparable increase in reliability or safety. This change is being proposed to support limiting the amount of surveillance testing that must be performed each maintenance and refueling outage. The proposed change will allow this Surveillance to extend the Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2). This proposed change was evaluated in accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991. Reviews of historical maintenance and surveillance data have shown that this test normally passes the Surveillance at the current Frequency. An evaluation has been performed using this data, and it has been determined that the effect on safety due to the extended Surveillance Frequency will be small. In addition, the proposed 24 month Surveillance Frequency, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) does not invalidate any assumptions in the plant licensing basis.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

LF.1 This change revises the Technical Specification setpoints for proposed Section 3.3 instrumentation to reflect Allowable Values consistent with the philosophy of NUREG-1434. These Allowable Values (to be included in Technical Specifications) have been established consistent with the WNP-2 Instrument Setpoint Methodology. The Allowable Value selection evaluation used actual WNP-2 operating and surveillance trend information to ensure the validity of the evaluation input data. All changes to safety analysis limits, applied in the methodologies, were evaluated and confirmed as ensuring safety analysis licensing acceptance limits are maintained. All design limits, applied in the methodologies, were confirmed as ensuring that applicable design requirements of the associated systems are maintained. The methodologies used to derive the Allowable Values are based on combining the uncertainties of the associated channels. The methodologies used in the evaluation are consistent with the guidance of ISA Standard, SP67.04-1982, "Setpoints for Nuclear Safety-Related Instruments used in Nuclear Power Plants," which was approved for use by the NRC in RG 1.105, Revision 2, February 1986. Plant calibration procedures will ensure the assumptions regarding calibration accuracy are maintained. The proposed Allowable Values have been established from each design or safety analysis limit by accounting for instrument accuracy, calibration and drift uncertainties, environmental effects, power supply fluctuations, as well as uncertainties related to process and primary element measurement accuracy using the WNP-2 Instrument Setpoint Methodology. The use of these methodologies for establishing Allowable Values ensures design or safety analysis limits are not exceeded in the event of transients or accidents and accounts for uncertainties and environmental conditions. (A)

"Specific"

L.1 The required actions for a trip system inoperable is revised to address trip Function (e.g., Reactor Pressure Vessel - High is a Function) capability. This is consistent with other Specifications that provide appropriate allowed out of service times as long as the actuation capability is maintained. The Function has lost trip capability if an ATWS-RPT trip cannot occur from the Function. ACTION B has also been added to allow trip capability to be lost for one of the two trip Functions for 72 hours. Currently, no time is allowed if trip capability is lost for a Function (i.e., both trip systems are inoperable for the given Function); a shutdown to MODE 2 is requied within 6 hours. The 72 hour allowance is considered acceptable because the other Function is continuing to maintain trip capability, and since the ATWS-RPT System is not assumed to function during any design basis accident or transient; it provides protection during a beyond design basis event, whose probability of occurrence is remote. In addition, the plant emergency operating procedures provide requirements to trip the recirculation pumps if an ATWS event occurs, regardless of whether or not the Allowable Values of the (B)

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) ATWS-RPT instrumentation Functions (reactor pressure or water level) have been exceeded. Thus in many ATWS event scenarios, the operators will manually trip the recirculation pumps (i.e., perform the ATWS-RPT function) prior to the instrumentation automatically performing the function.

L.2 An additional Required Action is proposed to allow removal of the associated recirculation pump from service. Since this action accomplishes the functional purpose of the instrumentation and enables continued operation in a previously approved condition, this change does not have a significant effect on safe operation.

L.3 The Frequency for the CHANNEL CALIBRATION is being changed from quarterly to 18 months. These instruments are highly reliable and the sensors are similar to those that are currently calibrated every 18 months. A review of the maintenance history has shown that no failures or out of tolerances have been discovered for this instrumentation during a CHANNEL CALIBRATION. In addition, the current setpoint calculations support an 18 month calibration frequency. This Frequency is also consistent with the BWR Standard Technical Specifications, NUREG-1434.

INSTRUMENTATION

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

LCO 3.3.5.1

3.3.3 The emergency core cooling system (ECCS) actuation instrumentation channels shown in Table 3.3.3-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.3-2. (LA.1)

APPLICABILITY: As shown in Table 3.3.3-1.

ACTION: add proposed Actions Note (A.1)

ACTION A

a. With an ECCS actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.3-2, declare the channel inoperable until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value. (LA.1)

ACTION A and Required Actions B.3, C.2, D.2.1, F.2, and G.2

b. With one or more ECCS actuation instrumentation channels inoperable, within 24 hours take the ACTION required by Table 3.3.3-1. (M.1)

Add proposed Required Actions B.1, B.2, C.1, D.1, E.1, F.1, and G.1

ACTIONS F and G

c. With either ADS trip system "A" or "B" inoperable, restore the inoperable trip system to OPERABLE status:

1. Within 7 days, provided that the HPCS and RCIC systems are OPERABLE; otherwise,

2. Within 72 hours.

Place channel in trip or (L.1)

ACTION H

Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to less than or equal to 150 (128) psig within the following 24 hours. (A.10) (L.3)

SURVEILLANCE REQUIREMENTS

Note 1 to Surveillance Requirements

4.3.3.1 Each ECCS actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.3.1-1.

SR 3.3.5.1.6

4.3.3.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed at least once per 18 (24) months. (LA.2) (LD.1) (B)

4.3.3.3 The ECCS RESPONSE TIME of each ECCS trip function shall be demonstrated to be within the limit at least once per 18 months. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific ECCS trip system.

(A.2) moved to LCO 3.5.1 and LCO 3.5.2

SURVEILLANCE REQUIREMENTS (Continued)

e. For the ADS by:

1. At least once per 31 days by verifying that the accumulator backup compressed gas system pressure in each bottle is ≥ 2200 psig.

SR 3.3.5.1.2 2. At least once per 31 days, performing a CHANNEL FUNCTIONAL TEST of the accumulator backup compressed gas system low pressure alarm system. 92 L.4

SR 3.3.5.1.4 3. At least once per 18 months:

a) Performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence, but excluding actual valve actuation.

b) Manually opening each ADS valve when the reactor steam dome pressure is greater than or equal to 100 psig* and observing that either:

1) The control valve or bypass valve position responds accordingly, or

2) There is a corresponding change in the measured steam flow.

M.2 Add proposed ACTION F for Functions 4.f and 5.e

SR 3.3.5.1.4

c) Performing a CHANNEL CALIBRATION of the accumulator backup compressed gas system low pressure alarm system and verifying an initiation setpoint of ≥ 140 psig on decreasing pressure and an alarm setpoint ≥ 135 psig on decreasing pressure. LA.3 LA.3

Table 3.3.5.1-1 Functions 4.f and 5.e

Table 3.3.5.1-1 Allowable Value Functions 4.f and 5.e

d) Verifying the nitrogen capacity in at least two accumulator bottles per division within the backup compressed gas system.

add proposed SR 3.3.5.1.6 for functions 4.f and 5.e

M.2

*The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure and flow are adequate to perform the test.

See Discussion of Changes for ITS: 3.5.1, "ECCS-Operating" in Section 3.5

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 Appropriate Required Actions have been added (proposed Required Actions B.1, B.2, C.1, D.1, E.1, F.1, and G.1) for response to loss of the initiation capability of a Function for both divisions/trip systems. These additional requirements provides clear direction of the necessary ACTIONS when in this condition. The Required Actions will only allow continued operations for 1 hour if a loss of initiation capability of a Function for both divisions/trip systems occurs.

M.2 Additional Functions (1.c, 1.d, 2.c, 2.d) are included to provide requirements for the low pressure ECCS pumps' LOCA Time Delay Relay instrumentation. The logic of this instrumentation is important to the proper functioning of the ECCS in response to a design basis accident. Appropriate ACTIONS and Surveillance Requirements have also been added. Since these Functions have been added, current Functions A.1.f and B.1.d have been clarified by the addition of "LOCA/LOOP," to properly describe the function of the Time Delay Relay. In addition, ACTION F and SR 3.3.5.1.5 have been added for the Accumulator Backup Compressed Gas System Pressure–Low Function (proposed Functions 4.f and 5.e). Currently, no specific ACTIONS are provided when one or more of the channels are inoperable, and, since the channels are arranged in a two-out-of-three logic, the associated ADS valves are declared inoperable when two of the channels in a subsystem are inoperable. No ACTION is required when only one channel per subsystem is inoperable. The proposed ACTION F will require an individual channel to be tripped in 8 days. When more than one channel in a subsystem is inoperable, ACTION F will require declaring the associated ADS valve inoperable, consistent with current licensing basis. The LOGIC SYSTEM FUNCTIONAL TEST requirement of SR 3.3.5.1.6 has been added to ensure the two-out-of-three logic is properly tested, similar to other ADS Functions. Currently, only a CHANNEL CALIBRATION is required for these instruments. These are additional restrictions on plant operation. 1B

M.3 A Note (proposed Note b) has been added to ensure the DGs are also covered by the associated instruments. Thus, when a channel is not restored, the affected DG will be declared inoperable in addition to the affected ECCS division. This is an additional restriction on plant operation.

M.4 Currently, a channel is allowed to be inoperable for 24 hours prior to requiring the ACTIONS of Table 3.3.3-1 to be entered. The ACTIONS of Table 3.3.3-1 then allow some time to trip or restore a channel. This additional time is being deleted, except for the time allowed for the minimum flow channels, of which only 1 day of the 7 days is being deleted. The proposed ACTIONS will allow 24 hours to trip or restore the inoperable channels (except for the minimum flow channels, which will allow 7 days), prior to

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 Trip setpoints are an operational detail that is not directly related to the OPERABILITY of the instrumentation. These details are proposed to be relocated to plant procedures. The Allowable Value is the required limitation for the parameter and this value is retained in the Technical Specifications. Changes to the relocated trip setpoints in procedures will be controlled by the provisions of 10 CFR 50.59.

LA.2 The details relating to methods for performing the LOGIC SYSTEM FUNCTIONAL TESTS are proposed to be relocated to the Bases. These details are not necessary to ensure the OPERABILITY of the Emergency Core Cooling System (ECCS) Instrumentation. The requirements of Specification 3.3.5.1 and the associated Surveillance Requirements are adequate to ensure the ECCS instruments are maintained OPERABLE. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LA.3 System design and operation details are proposed to be relocated to the Bases. Details relating to system design and operation (e.g., bypasses, associated division, specific equipment affected, etc.) are unnecessary in the LCO. These details are not necessary to ensure the OPERABILITY of the Emergency Core Cooling System (ECCS) Instrumentation. The requirements of Specification 3.3.5.1 and the associated Surveillance Requirements are adequate to ensure the ECCS instruments are maintained OPERABLE. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LB.1 The current Note allowing a delay in entering the associated Action statement has been clarified to allow current Functions C.1.c, C.1.f, and C.1.g (proposed Functions 3.c, 3.f, and 3.g) to be inoperable and delay entering the associated Action statement for 6 hours, regardless of the remaining ECCS initiation capability of the Function. For these three Functions, loss of one channel results in a loss of HPCS initiation capability. This condition was evaluated in the reliability analysis of NEDC-30936-P-A, December 1988, and found to be acceptable. This analysis is the basis for the current 6 hour allowance in the Note. The results of the NRC review of this generic reliability analysis as it relates to WNP-2 is documented an NRC Safety Evaluation Report (SER) dated May 15, 1992. The SER concluded that the generic reliability analysis is applicable to WNP-2, and that WNP-2 meets all requirements of the NRC SER accepting the generic reliability analysis. (B)

LD.1 The Frequency for performing the LOGIC SYSTEM FUNCTIONAL TEST of current Surveillance 4.3.3.2 (proposed SR 3.3.5.1.6) has been extended from 18 months to 24 months to facilitate a change to the (B)

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd) WNP-2 maintenance cycle from 12 months to 24 months. The current conditions in the northwest require that WNP-2 shut down each spring for an annual maintenance and refueling outage. Currently,most of the current Surveillances that are required to be performed on an 18 month interval are performed annually because they must be performed while the plant is shut down. This has resulted in increased testing, with a resultant increase in cost and personnel exposure, with no comparable increase in reliability or safety. This change is being proposed to support limiting the amount of surveillance testing that must be performed each maintenance and refueling outage. The proposed change will allow this Surveillance to extend the Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2). This proposed change was evaluated in accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991. Reviews of historical maintenance and surveillance data have shown that this test normally passes the Surveillance at the current Frequency. An evaluation has been performed using this data, and it has been determined that the effect on safety due to the extended Surveillance Frequency will be small. In addition, the proposed 24 month Surveillance Frequency, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) does not invalidate any assumptions in the plant licensing basis.

LF.1 This change revises the Technical Specification setpoints for proposed Section 3.3 instrumentation to reflect Allowable Values consistent with the philosophy of NUREG-1434. These Allowable Values (to be included in Technical Specifications) have been established consistent with the WNP-2 Instrument Setpoint Methodology. The Allowable Value selection evaluation used actual WNP-2 operating and surveillance trend information to ensure the validity of the evaluation input data. All changes to safety analysis limits, applied in the methodologies, were evaluated and confirmed as ensuring safety analysis licensing acceptance limits are maintained. All design limits, applied in the methodologies, were confirmed as ensuring that applicable design requirements of the associated systems are maintained. The methodologies used to derive the Allowable Values are based on combining the uncertainties of the associated channels. The methodologies used in the evaluation are consistent with the guidance of ISA Standard, SP67.04-1982, "Setpoints for Nuclear Safety-Related Instruments used in Nuclear Power Plants," which was approved for use by the NRC in RG 1.105, Revision 2, February 1986. Plant calibration procedures will ensure the assumptions regarding calibration accuracy are maintained. The proposed Allowable Values have been established from each design or safety analysis

B

TECHNICAL CHANGES - LESS RESTRICTIVE

LF.1 (cont'd) limit by accounting for instrument accuracy, calibration and drift uncertainties, environmental effects, power supply fluctuations, as well as uncertainties relating to process and primary element measurement accuracy using the WNP-2 Instrument Setpoint Methodology. The use of these methodologies for establishing Allowable Values ensures design or safety analysis limits are not exceeded in the event of transients or accidents and accounts for uncertainties and environmental conditions.

"Specific"

L.1 An option is provided for one or more inoperable channel(s) to place all inoperable channels in the tripped condition. This conservatively compensates for the inoperable status, restores the single failure capability and provides the required initiation capability of the instrumentation. Therefore, providing this option does not impact safety. However, if this action would result in system actuation, then declaring the system inoperable is the preferred action.

L.2 The requirements for automatic restoration of the HPCS water source to the suppression pool are dependent on the availability of sources and the need to realign. With the HPCS pre-aligned to the suppression pool, there is no need to require automatic realignment. When shutdown, an OPERABLE CST can provide sufficient water to adequately minimize the consequences of a vessel draindown event and automatic realignment is unnecessary. Only with insufficient water in the CST is automatic realignment necessary in the shutdown MODES. Therefore, the Applicability (including proposed Note c) is revised to reflect this.

L.3 The pressure at which ADS is required to be OPERABLE is increased from 128 psig to 150 psig to provide consistency of the OPERABILITY requirements for all ECCS and RCIC equipment. Small break loss of coolant accidents at low pressures (i.e., between 128 psig and 150 psig) are bounded by analysis performed at higher pressures. The ADS is required to operate to lower the pressure sufficiently so that the low pressure coolant injection (LPCI) and low pressure core spray (LPCS) systems can provide makeup to mitigate such accidents. Since these systems can begin to inject water into the reactor pressure vessel at pressures well above 150 psig (222 psid for LPCI and 285 psid for LPCS), there is no safety significance in the ADS not being OPERABLE between 128 psig and 150 psig.

L.4 The Frequency for current Surveillance 4.5.1.e.2 (initiation portion of the CHANNEL FUNCTIONAL TEST (CFT) requirement) has been extended from 31 days to 92 days. These instruments are highly reliable and the sensors function is similar to other instruments that have had their CFT Frequency previously extended. A review of maintenance history has shown that no failures or out of

TECHNICAL CHANGES - LESS RESTRICTIVE

L.4 (cont'd) tolerances have been discovered for this instrumentation during a CFT since the trip setpoints have been set in accordance to the current WNP-2 instrument setpoint methodology (which is consistent with the guidance of ISA Standard, SP67.04-1982, "Setpoints for Nuclear Safety-Related Instruments used in Nuclear Power Plants," and was approved for use by the NRC in RG 1.105, Revision 2, February 1986). The current setpoint calculations have been reviewed and support a 92 day CFT Frequency. In addition, the CFT Frequencies of other ADS instrumentation have previously been extended from 31 days to 92 days in accordance with Topical Report NEDC-30936-P-A, December 1988, and the NRC SER approving this topical report. The topical report determined that the change had a negligible impact on plant safety, and in fact should improve plant safety because of the reduced testing requirements. B

DISCUSSION OF CHANGES
ITS: 3.3.5.2 - RCIC SYSTEM INSTRUMENTATION

ADMINISTRATIVE

A.1 These proposed changes provide more explicit instructions for proper application of the ACTIONS for Technical Specification compliance. In conjunction with the proposed Specification 1.3, "Completion Times," the ACTIONS Note ("Separate Condition entry is allowed for each....") provides direction consistent with the intent of the existing ACTION for an inoperable RCIC instrumentation channel. Since this change only provides more explicit direction of the current interpretation of the existing specifications, this change is considered administrative.

A.2 The column title is now on a per Function basis rather than the current per Trip System basis. Thus, the number of required channels for current Functional Unit a is changed to "4", since there are two trip systems, with two channels per trip system. Current Functional Units b, c, and d are not affected since there is only one trip system for each of these three Functions (the number of channels remains the same). | (B) | (B)

A.3 The Manual Initiation switch and push button channel (current Functional Unit d) provides two inputs to the initiation logic. Therefore, using the ITS format that each input is considered a channel, the minimum channels is more appropriately specified as 2. Since the change involves no design change but is only a difference in nomenclature, this change is considered administrative. | (B)

A.4 A new Required Action has been added (proposed Required Action D.2.2) to allow the RCIC pump suction to be aligned to the suppression pool in lieu of tripping the channel, if a CST water level low channel is inoperable. Since this proposed action results in the same condition as if a channel were tripped (tripping one channel results in the suction being aligned to the suppression pool), this change is considered administrative.

A.5 The parenthetical conversion of the Allowable Value from plant elevation to actual condensate storage tank level has been deleted. The conversion is not needed in the Technical Specifications since the plant elevation is being retained. In addition, other Allowable Values that specify plant elevation do not have the conversion to actual tank level; the plant elevation is sufficient. Since the Allowable Value is still being retained, this change is considered administrative.

A.6 The CHANNEL FUNCTIONAL TEST (CFT) has been deleted since it is redundant to the LOGIC SYSTEM FUNCTIONAL TEST (LSFT). The Manual Initiation Function has no adjustable setpoints, but is based on switch manipulation. Therefore, the LSFT, which tests all contacts, will provide proper testing of the channel tested by a CFT. Thus, this change is considered administrative.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 Appropriate Required Actions have been added (proposed Required Actions B.1 and D.1) for response to loss of RCIC Initiation capability of a Function. These additional requirements provide clear direction of the necessary ACTIONS when in this Condition. The Required Actions will only allow continued operations for 1 hour if a loss of RCIC initiation capability of a Function occurs. 1 B

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 Trip setpoints are an operational detail that is not directly related to the OPERABILITY of the instrumentation. These details are proposed to be relocated to plant procedures. The Allowable Value is the required limitation for the parameter and this value is retained in the Technical Specifications. Changes to the relocated requirements in procedures will be controlled by the provisions of 10 CFR 50.59.

LA.2 The details relating to methods for performing the LOGIC SYSTEM FUNCTIONAL TEST are proposed to be relocated to the Bases. These details are not necessary to ensure the OPERABILITY of the Reactor Core isolation Cooling (RCIC) System Instrumentation. The requirements of Specification 3.3.5.2 and the associated Surveillance Requirements are adequate to ensure the RCIC instruments are maintained OPERABLE. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LA.3 System design and operation details are proposed to be relocated to the Bases. Details relating to system design and operation are unnecessary in the LCO. These details are not necessary to ensure the OPERABILITY of the Reactor Core Isolation Cooling (RCIC) System Instrumentation. The requirements of Specification 3.3.5.2 and the associated Surveillance Requirements are adequate to ensure the RCIC instruments are maintained OPERABLE. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LB.1 The current Note allowing a delay in entering the associated Action statement has been clarified to allow current Functions b and d (proposed Functions 2 and 4) to be inoperable and delay entering the associated Action statement for 6 hours, regardless

TECHNICAL CHANGES - LESS RESTRICTIVE

LB.1 (cont'd) of the remaining RCIC initiation capability of the Function. For these two Functions, loss of one channel results in a loss of RCIC initiation capability. This condition was evaluated in the reliability analysis of GENE-770-06-2-A, December 1992, and found to be acceptable. This analysis is the basis for the current 6 hour allowance in the Note. The results of the NRC review of this generic reliability analysis as it relates to WNP-2 is documented in NRC Safety Evaluation Report (SER) dated June 10, 1993. The SER concluded that the generic reliability analysis is applicable to WNP-2, and that WNP-2 meets all requirements of the NRC SER accepting the generic reliability analysis. (B)

LD.1 The Frequency for performing the LOGIC SYSTEM FUNCTIONAL TEST of current Surveillance 4.3.5.2 (proposed SR 3.3.5.2.4) has been extended from 18 months to 24 months to facilitate a change to the WNP-2 maintenance cycle from 12 months to 24 months. The current conditions in the northwest require that WNP-2 shut down each spring for an annual maintenance and refueling outage. Currently, most of the current Surveillances that are required to be performed on an 18 month interval are performed annually because they must be performed while the plant is shut down. This has resulted in increased testing, with a resultant increase in cost and personnel exposure, with no comparable increase in reliability or safety. This change is being proposed to support limiting the amount of surveillance testing that must be performed each maintenance and refueling outage. The proposed change will allow this Surveillance to extend the Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2). This proposed change was evaluated in accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991. Reviews of historical maintenance and surveillance data have shown that this test normally passes the Surveillance at the current Frequency. An evaluation has been performed using this data, and it has been determined that the effect on safety due to the extended Surveillance Frequency will be small. In addition, the proposed 24 month Surveillance Frequency, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) does not invalidate any assumptions in the plant licensing basis.

LF.1 This change revises the Technical Specification setpoints for proposed Section 3.3 instrumentation to reflect Allowable Values consistent with the philosophy of NUREG-1434. These Allowable Values (to be included in Technical Specifications) have been established consistent with the WNP-2 Instrument Setpoint Methodology. The Allowable Value selection evaluation used actual

TECHNICAL CHANGES - LESS RESTRICTIVE

LF.1 (cont'd) WNP-2 operating and surveillance trend information to ensure the validity of the evaluation input data. All changes to safety analysis limits, applied in the methodologies, were evaluated and confirmed as ensuring safety analysis licensing acceptance limits are maintained. All design limits, applied in the methodologies, were confirmed as ensuring that applicable design requirements of the associated systems are maintained. The methodologies used to derive the Allowable Values are based on combining the uncertainties of the associated channels. The methodologies used in the evaluation are consistent with the guidance of ISA Standard, SP67.04-1982, "Setpoints for Nuclear Safety-Related Instruments used in Nuclear Power Plants," which was approved for use by the NRC in RG 1.105, Revision 2, February 1986. Plant calibration procedures will ensure the assumptions regarding calibration accuracy are maintained. The proposed Allowable Values have been established from each design or safety analysis limit by accounting for instrument accuracy, calibration and drift uncertainties, environmental effects, power supply fluctuations, as well as uncertainties related to process and primary element measurement accuracy using the WNP-2 Instrument Setpoint Methodology. The use of these methodologies for establishing Allowable Values ensures design or safety analysis limits are not exceeded in the event of transients or accidents and accounts for uncertainties and environmental conditions. (B)

"Specific"

L.1 An option is provided for one or more inoperable channel(s) to place all inoperable channels in the tripped condition. This conservatively compensates for the inoperable status, restores the single failure capability and provides the required initiation capability of the instrumentation. Therefore, providing this option does not impact safety. However, if this action would result in system actuation, then declaring the system inoperable is the preferred action.

TABLE 3.3.6.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

ACTION STATEMENTS

ACTION 20 - Be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

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

ACTION 22 - Close the affected system isolation valves within 1 hour and declare the affected system inoperable.

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

ACTION 24 - Restore the manual initiation function to OPERABLE status within 8 hours or close the affected system isolation valves within the next hour and declare the affected system inoperable or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

ACTION 25 - Establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within 1 hour.

ACTION 26 - Lock close or close, as applicable, the affected system isolation valves within 1 hour and declare the affected system inoperable.

TABLE NOTATIONS

Note (a) *May be bypassed with reactor steam pressure < 1060 psig and all turbine stop valves closed.

**When handling irradiated fuel in the secondary containment and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

#During CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

Note 2 (a) to Surveillance Requirements A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition provided at least one other OPERABLE channel in the same trip system is monitoring that parameter.

(b) Also actuates the standby gas treatment system.

(c) DELETED

(d) A channel is OPERABLE if 2 of 4 detectors in that channel are OPERABLE.

(e) Also actuates secondary containment ventilation isolation dampers per Table 3.6.5.2-1.

Note (c) (f) Closes only RWCU system outboard isolation valve RWCU-V-4.

(g) Only valves RHR-V-123A and RHR-V-123B in Valve Group 5 are required for primary isolation.

Note (b) (h) Manual initiation isolates RCIC-V-8 only and only with a coincident reactor vessel level-low, level 3.

Note (d) (i) Not required for RHR-V-8 when control is transferred to the alternate remote shutdown panel during operational conditions 1, 2 & 3 and the isolation interlocks are bypassed. When RHR-V-8 control is transferred to the remote shutdown panel under operational modes 1, 2, and 3 the associated key lock switch will be locked with the valve in the closed position. Except RHR-V-8 can be returned to, and operated from, the control room, with the interlocks and automatic isolation capability reestablished in operational conditions 2 and 3 when reactor pressure is less than 135 psig.

Table 3.3.6.1-1

TABLE 3.3.2-2

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. PRIMARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level		
2.a 1) Low, Level 3	≥ 13.0 inches*	≥ 11.0 inches
1.a and 2.b 2) Low Low, Level 2	≥ -50 inches*	≥ -58 inches
2.c b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. Main Steam Line		
1) DELETED		
1.b 2) Pressure - Low	≥ 831 psig	≥ 811 psig
1.c 3) Flow - High	≤ 115.6 psid	≤ 124.6 psid
1.e d. Main Steam Line Tunnel Temperature - High	≤ 164°F	≤ 170°F
1.f e. Main Steam Line Tunnel ΔTemperature - High	≤ 80°F	≤ 90°F
1.d f. Condenser Vacuum - Low	≥ 23 inches Hg absolute pressure	≥ 21.5 inches Hg absolute Vacuum pressure
1.g and 2.e g. Manual Initiation (A.7 moved to LCO 3.3.6.2)	N.A.	N.A.
2. SECONDARY CONTAINMENT ISOLATION		
2.d a. Reactor Building Vent Exhaust Plenum Radiation - High	≤ 13.0 mR/h	≤ 16.0 mR/h
2.c b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
2.b c. Reactor Vessel Water Level - Low Low, Level 2	≥ -50 inches*	≥ -57 inches
2.e d. Manual Initiation	N.A.	N.A.

LA.1 9.5 LF.1 804 LF.1 7.2 M.6 B -58 LF.1 4 M.6

Specification 3.3.6.1

Table 3.3.6.1-1

TABLE 3.3.2-2 (Continued)
ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
3. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION (Continued)		
3.f f. RCIC Equipment Room Δ Temperature - High	≤ 50°F (LA.1)	≤ 60°F
3.g g. RWCU/RCIC Steam Line Routing Area Temperature - High	≤ 160°F	≤ 180°F
h. Drywell Pressure - High	≤ 1.65 psig	≤ 1.85 psig (R.1)
3.h i. Manual Initiation	N.A.	N.A.
5. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION		
5.d d. Reactor Vessel Water Level - Low, Level 3	≥ 13.0 inches*	≥ 11.0 (9.5) (LF.1) inches
5.e.b. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	≤ 125 psig	≤ 135 psig
5.a c. Equipment Area Temperature - High		
Pump Room A	≤ 140°F	≤ 150°F
Pump Room B	≤ 140°F (LA.1)	≤ 150°F
5.b d. Equipment Area Ventilation Δ Temp. - High		
Pump Room A	≤ 55°F	≤ 70°F
Pump Room B	≤ 55°F	≤ 70°F
e. Shutdown Cooling Return Flow Rate - High	≤ 174 inches H_2O	≤ 183 (L.11) inches H_2O
5.c f. RHR Heat Exchanger Area Temperature - High		
Room 606	≤ 130°F	≤ 140°F
Room 607	≤ 160°F	≤ 160°F
Room 605	≤ 140°F (LA.1)	≤ 150°F
Room 505	≤ 130°F	≤ 140°F
5.f g. Manual Initiation	N.A.	N.A.

*See Bases Figure B 3/4 3-1. (LA.1)

TABLE NOTATIONS

(B)

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Specification 3.3.6.1

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ADMINISTRATIVE (continued)

A.9 A Required Action has been added (proposed Required Action I.1) which allows the associated SLC subsystem to be declared inoperable if RWCU System isolation is not desired. Since this is what would be required if the RWCU System could not be isolated (i.e., the Function's purpose is to ensure the SLC subsystems function properly and the injected boron is not removed from the Reactor Coolant System), the change is considered administrative.

A.10 An action to "declare the affected system inoperable" is an unnecessary reminder that other Technical Specifications may be affected. This is essentially a "cross reference" between Technical Specifications that has been determined to be adequately provided through training.

A.11 The room number has been changed from "409" to "509" to correct a typographical error.

A.12 The CHANNEL FUNCTIONAL TEST (CFT) has been deleted since it is redundant to the LOGIC SYSTEM FUNCTIONAL TEST (LSFT). The Manual Initiation and SLC System Initiation channels have no adjustable setpoints, but are based on switch manipulation. The LSFT, which tests all contacts, will provide proper testing of the channels tested by a CFT. Therefore, this deletion is considered administrative.

A.13 The proper name for the turbine valves has been provided. Since this change is only a change in nomenclature, it is considered administrative. (B)

RELOCATED SPECIFICATIONS

R.1 The RCIC Drywell Pressure–High Function isolates the RCIC turbine exhaust vacuum breaker isolation valves (RCIC-V-110 and RCIC-V-113) coincident with a RCIC Steam Line Pressure–Low signal. However, these valves are not primary containment isolation valves, and they are not assumed in any design basis accident or transient analysis. Further, the evaluation, summarized in NEDO-31466 determined the loss of this instrumentation to be a non-significant risk contributor to core damage frequency and offsite release. Therefore, the requirements specified for this Function did not satisfy the NRC Policy Statement Technical Specification screening criteria as documented in the Application of Selection Criteria to the WNP-2 Technical Specifications and have been relocated to plant documents controlled in accordance with 10 CFR 50.59. (B)

TECHNICAL CHANGES - MORE RESTRICTIVE

M.5 (cont'd) normally operated. Appropriate ACTIONS have also been added for when the Function is inoperable in MODES 4 and 5. This is an additional restriction on plant operations and is consistent with the BWR Standard Technical Specifications, NUREG-1434.

M.6 The Main Steam Line Flow–High, Condenser Vacuum–Low, RCIC Steam Line Flow–High, and RCIC Steam Supply Pressure–Low Functions setpoints have been decreased to the proper Allowable Value. The new Allowable Values are based upon the most recent setpoint calculations. These are additional restrictions on plant operation. In addition, for clarity, the unit for the Condenser Vacuum–Low Function has been changed from absolute pressure to vacuum. (B) (B)

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 Trip setpoints are an operational detail that is not directly related to the OPERABILITY of the instrumentation. These details are proposed to be relocated to plant procedures. The Allowable Value is the required limitation for the parameter and this value is retained in the Technical Specifications. Changes to the relocated trip setpoints in procedures will be controlled by the provisions of 10 CFR 50.59.

LA.2 These portions of the current ACTION b (first sentences of b.1 and b.2) have been incorporated into the applicable ACTIONS and the Bases. If placing the inoperable channel(s) would cause an isolation, the Required Action of Condition A is not completed within the required Completion Time and Condition C would be required to be entered, as described in the Bases. In addition, if it is not desired to place a channel in trip even when placing it in trip does not result in an isolation, then ACTION C can also be entered. This case is similar to the case when placing a channel in trip results in an isolation. Since the same response is required, this change is one of presentation only and is considered administrative. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LA.3 Details of the methods for performing Required Actions (which trip system to trip) are proposed to be relocated to the Bases. These details are not necessary to be included in Technical Specifications to ensure actions are taken to restore isolation capability. The ACTIONS of Specification 3.3.6.1 are adequate to ensure action is taken to restore isolation capability (including tripping one of the affected trip systems). Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.7 (cont'd) Specification requirement to "lock" the valve used to isolate the penetration closed. The means by which the valves are maintained closed are left under plant specific controls. Therefore, this requirement is proposed to be relocated to plant procedures. Changes to the relocated requirements in procedure will be controlled by the provisions of 10 CFR 50.59.

LB.1 The current Note allowing a delay in entering the associated Action statement during performance of Surveillances has been clarified to provide direct indication of the intent of the current wording. The current words "provided at least one other OPERABLE channel in the same trip system is monitoring that parameter" are intended to ensure that the trip capability of the Function is maintained. However, it does not provide this assurance for all logic system designs. Therefore, the Note has been modified to state "provided the associated Function maintains isolation capability." This is the intent of the current Note and is based on previously conducted reliability analyses (NEDC-31677-P-A, June 1989, and NEDC-30851-P-A, Supplement 2, March 1989). The results of the NRC review of this generic reliability analysis as it relates to WNP-2 is documented in NRC Safety Evaluation Report (SER) dated March 2, 1992. The SER concluded that the generic reliability analysis is applicable to WNP-2, and that WNP-2 meets all requirements of the NRC SER accepting the generic reliability analysis. (B)

LD.1 The Frequencies for performing the LOGIC SYSTEM FUNCTIONAL TEST of current Surveillance 4.3.2.2 (proposed SR 3.3.6.1.6) and the ISOLATION INSTRUMENTATION RESPONSE TIME test of current Surveillance 4.3.2.3 (proposed SR 3.3.6.1.7) have been extended from 18 months to 24 months to facilitate a change to the WNP-2 maintenance cycle from 12 months to 24 months. The current conditions in the northwest require that WNP-2 shut down each spring for an annual maintenance and refueling outage. Currently, most of the current Surveillances that are required to be performed on an 18 month interval are performed annually because they must be performed while the plant is shut down. This has resulted in increased testing, with a resultant increase in cost and personnel exposure, with no comparable increase in reliability or safety. This change is being proposed to support limiting the amount of surveillance testing that must be performed each maintenance and refueling outage. The proposed change will allow these Surveillances to extend their Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2). This proposed change was evaluated in accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991.

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd) Reviews of historical maintenance and surveillance data have shown that these tests normally pass their Surveillances at the current Frequency. An evaluation has been performed using this data, and it has been determined that the effect on safety due to the extended Surveillance Frequency will be small. In addition, the proposed 24 month Surveillance Frequencies, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) do not invalidate any assumptions in the plant licensing basis.

LE.1 The Frequency for performing the CHANNEL CALIBRATION Surveillance of current Surveillance 4.3.2.1 and Table 4.3.2.1-1 for Trip Function 3.a, the RWCU differential flow instrumentation (proposed SR 3.3.6.1.5 for Function 4.a) has been extended from 18 months to 24 months to facilitate a change to the WNP-2 maintenance cycle from 12 months to 24 months. The current conditions in the northwest require that WNP-2 shut down each spring for an annual maintenance and refueling outage. Consequently, most of the current Surveillances that are required to be performed on an 18 month interval are performed annually since they must be performed while the plant is shut down. This has resulted in increased testing, with a resultant increase in cost and personnel exposure, with no comparable increase in reliability or safety. This change is being proposed to support limiting the amount of surveillance testing that must be performed each maintenance and refueling outage. The proposed change will allow this Surveillance to extend the Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2). The CHANNEL CALIBRATION Surveillance will continue to be performed in the same manner as it has been in that no modifications to test methodologies or station equipment have been included in this request. Equipment required to mitigate the consequences of an accident will not be affected, except that the frequency of calibrating the instrumentation will be extended to accommodate a 24 month maintenance cycle (i.e., no setpoint changes are necessary). The scope of this request is being limited to those instruments which are calibrated during the annual refueling outage, because the Surveillance is performed during a plant shutdown.

Surveillance 4.3.2.1 and Table 4.3.2.1-1 currently requires the CHANNEL CALIBRATION to be performed once per 18 months for Trip Function 3.a. The CHANNEL CALIBRATION Surveillance is performed to ensure that at a previously evaluated setpoint actuation takes place to provide the required safety function. By increasing the maintenance cycle from 12 months to 24 months, the time interval for the CHANNEL CALIBRATION Surveillance for this instrumentation will be increased. However, as currently required by WNP-2 TS, CHANNEL FUNCTIONAL TESTS are performed during the operating cycle

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) more frequently than the CHANNEL CALIBRATION Surveillance. These CHANNEL FUNCTIONAL TESTS detect failures of the instrumentation channels, except for field devices, such as transmitters, that are only tested once every 12 or 18 months. Gross instrumentation failures are detected by alarms or by a comparison with redundant and independent indications. Instrumentation purchased for these functions are highly reliable and meet the design criteria of safety related equipment. The instrumentation is designed with redundant and independent channels which provide means to verify proper instrumentation performance during operation, and adequate redundancy to ensure a high confidence of system performance even with the failure of a single component. Based on this discussion and the drift analysis performed, the Supply System has concluded that the impact on instrumentation was small, if any, as a result of this change.

NRC Generic Letter 91-04 (GL91-04) provided guidance to licensees on the type of analysis and information required to justify a change to the surveillance interval for instrument calibrations. Seven specific actions were delineated in GL91-04 and are repeated below with the applicable response. This discussion is meant as a generic discussion to provide insight into the methodology the Supply System used to evaluate the affects of an increased surveillance interval on instrument drift. The results support the conclusion that instrument drift is not a significant factor in increasing the surveillance interval.

1. Confirm that instrument drift as determined by as-found and as-left calibration data from surveillance and maintenance records has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

   The effect of increased calibration intervals on the TS instrumentation for WNP-2 to accommodate a 24 month maintenance cycle has been determined. Two issues associated with the instrumentation have been evaluated: a) instrument availability based on consideration of historical instrument test failures and b) instrument drift.

   a) Instrument Availability with Consideration to Historical Instrument Test Failures

      A search was performed of the equipment history of the line items covered by this request. This search was conducted to identify equipment problems since 1990. Each of the problems were reviewed to determine the cause. The purpose of this evaluation was to determine the impact that an increase in the surveillance interval has on instrument availability. This review identified that instrument failure rates detected by the annual CHANNEL CALIBRATION Surveillance were insignificant. Because of system

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd)

The methodology used to determine the magnitude of instrument drift provides a high degree of probability and a high degree of confidence for a bounding calibration interval of 30 months for each instrument type is included in the analysis. The specific instrument applications are contained in the appropriate section of the ITS submittal.

4. Confirm that a comparison of the projected instrument drift errors has been made with the values of drift used in the setpoint analysis. If this results in revised setpoints to accommodate larger drift errors, provide proposed TS changes to update trip setpoints. If the drift errors result in revised safety analysis to support existing setpoints, provide a summary of the updated analysis conclusions to confirm that safety limits and safety analysis assumptions are not exceeded.

   The 30 month projected drift number was compared to the present allowance for the instrument application. The drift for each instrument type fell within the present bounds of the acceptance criteria. Data for intervals as large as 650 days were analyzed showing drift remained within the current acceptance criteria, These analyses were done in accordance with ISA Standard, SP67.04-1982, "Setpoints for Nuclear Safety-Related Instruments used in Nuclear Power Plants," which was approved for use by the NRC in RG 1.105, Revision 2, February 1986. To extend to a 30 month surveillance interval, justification of either acceptable projected drift or justification from the instrument manufacturer was used. In no case was the setpoint of an instrument changed to accommodate a drift error larger than previously evaluated. 1B 1B

5. Confirm that the projected instrument errors caused by drift are acceptable for control of plant parameters to effect a safe shutdown with associated instrumentation.

   As discussed in response to item 4 above, the justification for extending the surveillance interval of an instrument was an instrument drift calculation within the existing design basis with the extended time interval. Additional factors evaluated included more frequent testing or a manufacturer recommendation. In no case was the existing safe shutdown analysis changed to accommodate a larger drift error. 1B

6. Confirm that all conditions and assumptions of the setpoint and safety analyses gave been checked and are appropriately reflected in the acceptance criteria of plant surveillance procedures for channel checks, channel functional tests, and channel calibrations.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) The Supply System has not changed any of the setpoint or acceptance criteria of the present CHANNEL CALIBRATION Surveillances, therefore, there is no cause to reverify the criteria used to establish the acceptance criteria in the surveillance test.

7. Provide a summary description of the program for monitoring and assessing the effects of increased calibration surveillance intervals on instrument drift and its effects on safety.

The instrumentation program at WNP-2 includes the verification that the setpoint is within established administrative limits during the CHANNEL FUNCTIONAL TESTS. If not, the instrument will be recalibrated. If the instrument is found beyond the Allowable Value, a Problem Evaluation Report (PER) is written. The review of the PER will require, based on the results of that review, that a decision on the appropriate calibration interval be made. Such a decision will consider such things as shortening the surveillance test interval (STI), changing the setpoint of the instrument or leaving the STI at 24 months. Review of the Surveillance results will be performed until such time as we determine that further evaluation is no longer necessary.

LF.1 This change revises the Technical Specification setpoints for proposed Section 3.3 instrumentation to reflect Allowable Values consistent with the philosophy of NUREG-1434. These Allowable Values (to be included in Technical Specifications) have been established consistent with the WNP-2 Instrument Setpoint Methodology. The Allowable Value selection evaluation used actual WNP-2 operating and surveillance trend information to ensure the validity of the evaluation input data. All changes to safety analysis limits, applied in the methodologies, were evaluated and confirmed as ensuring safety analysis licensing acceptance limits are maintained. All design limits, applied in the methodologies, were confirmed as ensuring that applicable design requirements of the associated systems are maintained. The methodologies used to derive the Allowable Values are based on combining the uncertainties of the associated channels. The methodologies used in the evaluation are consistent with the guidance of ISA Standard, SP67.04-1982, "Setpoints for Nuclear Safety-Related Instruments used in Nuclear Power Plants," which was approved for use by the NRC in RG 1.105, Revision 2, February 1986. Plant calibration procedures will ensure the assumptions regarding calibration accuracy are maintained. The proposed Allowable Values have been established from each design or safety analysis limit by accounting for instrument accuracy, calibration and drift uncertainties, environmental effects, power supply fluctuations,

(B)

TECHNICAL CHANGES - LESS RESTRICTIVE

LF.1 (cont'd) as well as uncertainties related to process and primary element measurement accuracy using the WNP-2 Instrument Setpoint Methodology. The use of these methodologies for establishing Allowable Values ensures design or safety analysis limits are not exceeded in the event of transients or accidents and accounts for uncertainties and environmental conditions.

"Specific"

L.1 The current ACTIONS differentiate between whether channels are inoperable in one or both trip systems. With channels out in both trip systems, the current ACTIONS do not allow all inoperable channels to be placed in the tripped condition even if this would not cause an isolation. Because of the varied logic in isolation actuation systems there is no relatively simple set of actions that can be defined to cover all situations. The proposed Specifications have combined the ACTIONS for inoperable channels, independent of whether one or both trip systems are affected. This allows the conservative action of tripping the inoperable channels which is preferable to initiating a shutdown as is currently required in many cases. If all channels are not restored or tripped, then the ACTIONS referenced in the proposed Table are required, similar to the current TS.

L.2 This ACTION has been modified to allow isolation of the affected penetration instead of requiring a unit shutdown. Isolation of the affected penetration performs the safety function of the instruments. The Reactor Vessel Water Level—Low, Level 3 Function affects the Group 5 valves only. The Group 5 valves only affect the LPCI A and B subsystems, and operation can continue with these valves isolated (i.e., the associated LPCI subsystem is inoperable and ACTIONS are provided in proposed LCO 3.5.1 (current Specification 3.5.1) that allow operation for a short time). If the penetration(s) is not isolated within 1 hour (as provided in proposed ACTION F), the plant must be placed in MODES 3 and 4 in accordance with proposed ACTION H. | (B)

L.3 The SLC System is not required in MODE 3 since no control rods can be withdrawn (the MODE switch in shutdown rod block precludes rod movement per LCO 3.3.2.1). This is consistent with the current and proposed Applicability requirements for the SLC System. Therefore, the MODE 3 requirement for the SLC Initiation Function has been deleted.

L.4 The RCIC/RHR Steam Line Flow—High Function isolates the RCIC System on a pipe break in the RHR steam condensing mode piping (RCIC was originally designed to supply steam to this system). The RHR steam condensing mode has been permanently isolated from the RCIC System through a plant modification. Therefore, the instrumentation is no longer needed to isolate the RCIC System, and has been deleted from Technical Specifications.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.5 Since the system isolations on low water level and shutdown cooling return flow rate high in MODES 4 and 5 are provided to mitigate a vessel draindown event, an intact system fulfills the function of one trip system of isolation instrumentation. Therefore, the second trip system requirement is not required (proposed Note e to Table 3.3.6.1-1) provided system integrity is maintained. With the piping not intact or with maintenance being performed that has the potential for draining the reactor vessel through the system, both trip systems are required for RHR System isolation in MODES 4 and 5.

L.6 The MODE 1 and 2 Applicability requirements for the Reactor Vessel Water Level—Low, Level 3, Equipment Area Temperature—High, Equipment Area Ventilation Differential Temperature—High, and RHR Heat Exchanger Area Temperature—High Functions have been deleted. These instruments are designed to isolate the RHR SDC portion of the RHR System if an RCS leak is detected to ensure offsite dose limits are not exceeded. The Reactor Vessel Pressure—High Function ensures that the RHR Shutdown Cooling valves are isolated in MODE 1 and MODE 2 when above the RHR cut-in permissive pressure setpoint, since this Function isolates the valves when above the setpoint. When in MODE 2 below the setpoint, other Technical Specification requirements essentially ensure that RHR Shutdown Cooling is not in service (LCO 3.5.1 requires all LPCI to be OPERABLE in MODE 2, and with RHR aligned to the shutdown cooling mode, LPCI will be inoperable). In addition, plant procedures require that RHR be aligned to the LPCI mode, and the recirculation pumps to operating (which would necessitate securing the shutdown cooling mode) prior to entering MODE 2. The Current Licensing Basis (CLB) does not assume these instruments function in the flood protection mode (PAM instruments described in LCO 3.3.3.1 perform this function) or for environmental control response (which is controlled outside TS). The CLB also does not assume these instruments function to provide alarm or monitoring capabilities, nor to mitigate a leak in the RHR test or suppression pool cooling line (since when in these modes, the system is circulating suppression pool water, not RCS water). Therefore, the MODE 1 and 2 requirements for these Functions have been deleted.

L.7 The Required Action if the Required Action and associated Completion Time of Conditions A or B are not met for the Reactor Vessel Water Level—Low Low, (Level 2) is proposed to allow isolation of the affected main steam line (currently a shutdown is required). Some conditions may affect the isolation logic for only one main steam line. In these cases, it is not necessary to require a shutdown of the unit; rather, isolation of the affected line returns the system to a status where it can perform the remainder of its isolation function, and continued operation is allowed (although it may be at a reduced power level in MODE 2.)

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.8 The action to isolate all main steam lines is a sufficient action with the referenced Functions inoperable and will require being in MODE 2 to avoid a scram. The requirement to be in MODE 2 is therefore implicit and is deleted. The time allowed to isolate the associated main steam lines is extended from 6 hours to 12 hours. The additional time is provided to allow for more orderly power reduction.

L.9 The time allowed to isolate the associated penetration if a Manual Initiation Function is inoperable has been extended from 9 hours (8 hours to restore the channel and 1 hour to isolate the penetration) to 24 hours. The current time is considered overly conservative since the Manual Initiation Function is not assumed in any accident or transient analysis in the FSAR; automatic Functions are the Functions assumed to isolate the penetration. This change is consistent with the BWR Standard Technical Specifications, NUREG-1434.

L.10 The actions have been modified for when a Shutdown Cooling (SDC) System reactor vessel low water level isolation channel is inoperable. Currently, if the channel is not tripped within the appropriate time, the valves are required to be closed within 1 hour. This action however, will result in a loss of shutdown cooling, and could in fact, result in a more significant safety problem than if the valves were left open with inoperable channels. Therefore, the BWROG proposed new ACTIONS, and the NRC staff accepted these ACTIONS, as shown in the BWR Standard Technical Specifications, NUREG-1434. The new ACTIONS (proposed ACTION J) would require action to be immediately initiated to isolate the affected line or to restore the channel(s) to OPERABLE status. The Bases describes circumstances under which each Required Action is to be taken. These new actions ensure that SDC is not interrupted when needed, yet also ensures action is continued to restore the channel(s) if this is the case.

L.11 The RHR shutdown cooling (SDC) suction flow rate - high isolation instrumentation is deleted from the proposed Technical Specifications. The following paragraphs describe the RHR SDC system leak detection instrumentation and provide justification for deleting the high flow isolation instrumentation from the Technical Specifications. The high flow isolation instrumentation is not needed to mitigate design basis events; however, for reasons of equipment protection, the instrumentation will be retained as part of the RHR SDC isolation system.

The WNP-2 RHR SDC system contains five isolation valves that are part of the primary containment isolation system. The five valves are members of the Isolation Group 6. The following signals isolate the Group 6 valves:

TECHNICAL CHANGES - LESS RESTRICTIVE

L.11 (cont'd)

- Reactor vessel water level - low, level 3
- Reactor vessel (RHR cut-in permissive) pressure - high
- Equipment area temperature - high
- Equipment area ventilation differential temperature - high
- Shutdown cooling suction flow rate - high
- RHR heat exchanger area temperature - high
- Manual initiation

This proposed change deals only with the shutdown cooling suction flow rate - high instrumentation. Accidents and events described in the FSAR do not credit the RHR SDC suction flow rate - high instrumentation to mitigate any accident or event. The current requirement for this instrumentation requires 2 channels (one per trip system) to be OPERABLE in MODES 1, 2, and 3. The RHR System is maintained isolated while in MODE 1 and MODES 2 and 3 above the RHR SDC cut-in permissive pressure by the reactor vessel pressure - high isolation (with an Allowable Value of $\leq$ 159 psig). The reactor vessel pressure - high instrumentation is designed to be single failure proof, and is required to be OPERABLE by the proposed Technical Specifications. The reactor vessel pressure - high instrumentation ensures the Group 6 valves cannot be opened above this pressure. Therefore, the RHR SDC suction flow rate - high instrumentation is not necessary to provide an isolation signal during these MODES and conditions.

The proposed Technical Specifications require all ECCS subsystems to be OPERABLE during MODES 1, 2, and 3 (proposed LCO 3.5.1). The LPCI subsystems (LPCI is a mode of the RHR System, similar to SDC being a mode of the RHR System) cannot be OPERABLE in MODE 1 or 2 unless the LPCI subsystems are aligned in the standby mode for LPCI operation. This precludes the RHR SDC isolation valves from being open. Therefore, when changing from MODE 3 to MODE 2 with reactor pressure less than the RHR cut-in permissive pressure, proposed LCO 3.0.4 and SR 3.0.4 will ensure that the MODE change (from MODE 3 to MODE 2) is not made unless LPCI is OPERABLE, including alignment in the standby mode for LPCI operation. Therefore, the RHR SDC isolation valves will be maintained closed during MODE 2 with reactor pressure less than the RHR cut-in permissive pressure.

The proposed Technical Specifications also require the reactor vessel water level - low, level 3 instrumentation to be OPERABLE in MODES 3, 4, and 5. A break in the RHR SDC system piping outside containment will be mitigated by this instrumentation as

TECHNICAL CHANGES - LESS RESTRICTIVE

L.11 (cont'd) discussed in the FSAR safety analysis. In addition, area high temperature isolations are also available as a backup to the low water level during MODE 3 with reactor pressure less than the RHR cut-in permissive pressure.

Therefore, since at all times that RHR SDC is in operation, containment isolation will be accomplished/maintained via the other safety-related instrumentation, the shutdown cooling suction flow rate - high instrumentation is not needed and has been deleted from the Technical Specifications.

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

ACTION STATEMENTS

ACTION 20 - Be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

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

ACTION 22 - Close the affected system isolation valves within 1 hour and declare the affected system inoperable.

ACTION 23 - Be in at least STARTUP within 6 hours

ACTION C ACTION 24 - Restore the manual initiation function to OPERABLE status within 8 hours or close the affected system isolation valves within the next hour and declare the affected system inoperable or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

ACTION C ACTION 25 - Establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within 1 hour

ACTION 26 - Lock close or close, as applicable, the affected system isolation valves within 1 hour and declare the affected system inoperable

TABLE NOTATIONS

*May be bypassed with reactor steam pressure ≤ 1060 psig and all turbine stop valves closed.

Note (b) to Table 3.3.6.2-1 **When handling irradiated fuel in the secondary containment and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

Note (c) to Table 3.3.6.2-1 #During CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

Note 2 (a) to Surveillance Requirements A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition provided at least one other OPERABLE channel in the same trip system is monitoring that parameter.

(b) Also actuates the standby gas treatment system.

(c) ~~DELETED~~

(d) A channel is OPERABLE if 2 or 4 detectors in that channel are OPERABLE.

(e) ~~Also actuates secondary containment ventilation isolation dampers per Table 3.6.5.2-1.~~

(f) Closes only RWCU system outboard isolation valve RWCU-V-4.

(g) Only valves RHR-V-123A and RHR-V-123B in Valve Group 5 are required for primary isolation.

(h) Manual initiation isolates RCIC-V-8 only and only with a coincident reactor vessel level-low, level 3.

(i) Not required for RHR-V-8 when control is transferred to the alternate remote shutdown panel during operational conditions 1, 2 & 3 and the isolation interlocks are bypassed. When RHR-V-8 control is transferred to the remote shutdown panel under operational modes 1, 2, and 3 the associated key lock switch will be locked with the valve in the closed position. Except RHR-V-8 can be returned to, and operated from, the control room, with the interlocks and automatic isolation capability reestablished in operational conditions 2 and 3 when reactor pressure is less than 135 psig.

See Discussion of Changes for ITS 3.3.6.1, Primary Containment Isolation Instrumentation, in this Section.

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.5 (cont'd) the associated Surveillance Requirements are adequate to ensure the secondary containment isolation instruments are maintained OPERABLE. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LB.1 The current Note allowing a delay in entering the associated Action statement during performance of Surveillances has been clarified to provide direct indication of the intent of the current wording. The current words "provided at least one other OPERABLE channel in the same trip system is monitoring that parameter" are intended to ensure that the trip capability of the Function is maintained. However, it does not provide this assurance for all logic system designs. Therefore, the Note has been modified to state "provided the associated Function maintains isolation capability." This is the intent of the current Note and is based on previously conducted reliability analyses (NEDC-31677-P-A, June 1989, and NEDC-30851-P-A, Supplement 2, March 1989). The results of the NRC review of this generic reliability analysis as it relates to WNP-2 is documented in NRC Safety Evaluation Report (SER) dated March 2, 1992. The SER concluded that the generic reliability analysis is applicable to WNP-2, and that WNP-2 meets all requirements of the NRC SER accepting the generic reliability analysis. (B)

LD.1 The Frequency for performing the LOGIC SYSTEM FUNCTIONAL TEST of current Surveillance 4.3.2.2 (proposed SR 3.3.6.2.4) has been extended from 18 months to 24 months to facilitate a change to the WNP-2 maintenance cycle from 12 months to 24 months. The current conditions in the northwest require that WNP-2 shut down each spring for an annual maintenance and refueling outage. Currently, most of the current Surveillances that are required to be performed on an 18 month interval are performed annually because they must be performed while the plant is shut down. This has resulted in increased testing, with a resultant increase in cost and personnel exposure, with no comparable increase in reliability or safety. This change is being proposed to support limiting the amount of surveillance testing that must be performed each maintenance and refueling outage. The proposed change will allow this Surveillance to extend the Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2). This proposed change was evaluated in accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991. Reviews of historical maintenance and surveillance data have shown that this test normally passes the Surveillance at the current Frequency. An evaluation has been performed using this data, and

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd) it has been determined that the effect on safety due to the extended Surveillance Frequency will be small. In addition, the proposed 24 month Surveillance Frequency, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) does not invalidate any assumptions in the plant licensing basis.

LF.1 This change revises the Technical Specification setpoints for proposed Section 3.3 instrumentation to reflect Allowable Values consistent with the philosophy of NUREG-1434. These Allowable Values (to be included in Technical Specifications) have been established consistent with the WNP-2 Instrument Setpoint Methodology. The Allowable Value selection evaluation used actual WNP-2 operating and surveillances trend information to ensure the validity of the evaluation input data. All changes to safety analysis limits, applied in the methodologies, were evaluated and confirmed as ensuring safety analysis licensing acceptance limits are maintained. All design limits, applied in the methodologies, were confirmed as ensuring that applicable design requirements of the associated systems are maintained. The methodologies used to derive the Allowable Values are based on combining the uncertainties of the associated channels. The methodologies used in the evaluation are consistent with the guidance of ISA Standard, SP67.04-1982, "Setpoints for Nuclear Safety-Related Instruments used in Nuclear Power Plants," which was approved for use by the NRC in RG 1.105, Revision 2, February 1986. Plant calibration procedures will ensure the assumptions regarding calibration accuracy are maintained. The proposed Allowable Values have been established from each design or safety analysis limit by accounting for instrument accuracy, calibration and drift uncertainties, environmental effects, power supply fluctuations, as well as uncertainties related to process and primary element measurement accuracy using the WNP-2 Instrument Setpoint Methodology. The use of these methodologies for establishing Allowable Values ensures design or safety analysis limits are not exceeded in the event of transients or accidents and accounts for uncertainties and environmental conditions.

"Specific"

L.1 The current actions differentiate between whether channels are inoperable in one or both trip systems. With channels out in both trip systems, the current ACTIONS do not allow all inoperable channels to be placed in the tripped condition even if this would not cause an isolation. Because of the varied logic in isolation actuation systems there is no relatively simple set of actions that can be defined to cover all situations. The proposed Specifications have combined the ACTIONS for inoperable channels, independent of whether one or both trip systems are affected. This allows the conservative action of tripping the inoperable channels which is preferable to initiating a shutdown as is

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) currently required in many cases. If all channels are not restored or tripped, then the ACTIONS referenced in the proposed Table are required, similar to the current TS.

L.2 New Required Actions have been added (proposed Required Actions C.1.2 and C.2.2) to require declaring the affected components inoperable and taking the appropriate actions in the associated Secondary Containment Isolation Valve (SCIV) or SGT Systems Specification if the associated penetrations and SGT subsystems are not placed in the proper condition within 1 hour. Currently, the ACTIONS appear to require either a shutdown or a Specification 3.0.3 entry, which would also result in an immediate shutdown. Since this instrument provides a signal for the SCIVs and SGT System (i.e., it supports SCIVs and SGT System OPERABILITY), it is appropriate that the proper action would be to declare the associated SCIVs and SGT subsystems inoperable. The current requirements are overly restrictive, in that if the associated SCIVs and SGT subsystems were inoperable for other reasons, a much longer restoration time is provided. Currently if an instrument is inoperable but the associated SCIVs and SGT subsystems are otherwise fully OPERABLE, an immediate shutdown is required.

L.3 Automatic isolation capabilities on reactor vessel water level decreases are not necessary during CORE ALTERATIONS. CORE ALTERATIONS do not result in any increased potential for vessel draindown. If ongoing activities do involve a potential for draining the reactor vessel, the proposed Applicability will still require the Reactor Vessel Water Level—Low Low, Level 2 Function to be OPERABLE.

add proposed Functions 1, 2, and 3 (M.2)

Table 3.3.7.1-1

TABLE 3.3.7.1-1

(A.1) CREF ~~RADIATION MONITORING~~ INSTRUMENTATION

	INSTRUMENTATION	MINIMUM CHANNELS OPERABLE	APPLICABLE CONDITIONS	Allowable ~~Alarm~~ Value SETPOINT (A.1)	ACTION
1.	Main Control Room Ventilation Radiation Monitor	2/intake	1,2,3,(5) and * (L.1) add proposed footnotes (a) and (b) (L.1)	≤ 5000 cpm (3800 M.3)	70 E/F
2.	Area Monitors				
a.	Criticality Monitors				
1)	New Fuel Storage Vault	2	#	≤ 5 R/h(a)	71
2)	Spent Fuel Storage Pool	1	##	≤ 20 mR/h	71

add proposed footnotes (a) and (b) (L.1)

TABLE NOTATIONS

*When the main condenser air evacuation system is in operation. (L.1)

#With fuel in the new fuel storage vault.

##With fuel in the spent fuel storage pool.

(a)Alarm setpoint set IAW 10 CFR 70.24.a.1:

See Discussion of Changes for CTS: 3/4.3.7.1, in this Section.

ACTION STATEMENTS

ACTION 70 -

(M.4) add proposed Required Action F.1

Action E / Action F a. With one of the required monitors inoperable, (L.2) manually isolate the associated remote air intake within 1 hour; restore the inoperable channel to OPERABLE status within 7 days, (L.3) or, within the next 6 hours, initiate and maintain operation of the control room emergency filtration system in the pressurization mode of operation.

Action E b. With both of the required monitors inoperable, initiate and maintain operation of the control room emergency filtration system in the pressurization mode of operation within 1 hour. (L.3) (M.4)

ACTION 71 - With the required monitor inoperable, assure a portable continuous monitor with the same alarm setpoint is OPERABLE in the vicinity of the installed monitor during any fuel movement. If no fuel movement is being made, perform area surveys of the monitored area with portable monitoring instrumentation at least once per 24 hours.

(N.4) add proposed Required Action E.1 (including Note)

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Table 3.3.7.1-1

TABLE 4.3.7.1-1

CREF RADIATION ~~MONITORING~~ INSTRUMENTATION SURVEILLANCE REQUIREMENTS

(A.1)

INSTRUMENTATION	SR 3.3.7.1.1 CHANNEL CHECK	SR 3.3.7.1.2 CHANNEL FUNCTIONAL TEST	SR 3.3.7.1.3 CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
4.x. Main Control Room Ventilation Radiation Monitor	S	M (92 days) (B.1)	R	1, 2, 3, (a) and (b)
2. Area Monitors				
a. Criticality Monitors				
1) New Fuel Storage Vault	S	H	R	#
2) Spent Fuel Storage Pool	S	H	R	##

L.1: add proposed footnotes (a) and (b)

TABLE NOTATIONS

#With fuel in the new fuel storage vault.

##With fuel in the spent fuel storage pool.

*When the main condenser air evacuation system is in operation. (L.1)

add proposed footnotes (a) and (b) (L.1)

add proposed Functions 1, 2, and 3 (M.2)

See Discussion of Changes for CTS: 3/4.3.7.1, in this Section

(B) (B)

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SURVEILLANCE REQUIREMENTS (Continued)

SR 3.3.7.1.4 2. Verifying that on each of the below pressurization mode actuation test signals, the train automatically switches to the pressurization mode of operation and the control room is maintained at a positive pressure of 1/8 inch water gauge relative to the outside atmosphere during train operation at a flow rate less than or equal to 1000 cfm: A.4

a) Drywell pressure-high,

b) Reactor vessel water level-low, and

c) Reactor Building exhaust plenum-high radiation.

3. Verifying that the heaters dissipate 5.0 ± 0.5 kW when tested in accordance with ANSI N510-1980.

f. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter bank satisfies the inplace penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 while operating the train at a flow rate of 1000 cfm ± 10%.

g. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorber bank satisfies the inplace penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 for a halogenated hydrocarbon refrigerant test gas while operating the train at a flow rate of 1000 cfm ± 10%.

B

See Discussion of Changes for ITS 3.7.3, CREF System, in Section 3.7.

DISCUSSION OF CHANGES
ITS: 3.3.7.1 - CREF SYSTEM INSTRUMENTATION

ADMINISTRATIVE

A.1 The Functions being retained are the Control Room Emergency Filtration System Functions. Therefore, the LCO statement has been modified to require these Functions. In addition, since the new Functions being added (see Comment M.2) have Allowable Values, the alarm setpoint column has been renamed Allowable Value. Since this change is a presentation preference only, it is considered administrative.

A.2 These proposed changes provide more explicit instructions for proper application of the ACTIONS for Technical Specification compliance. In conjunction with the proposed Specification 1.3, "Completion Times," the ACTIONS Note ("Separate Condition entry is allowed for each....") and the wording for ACTION E provides direction consistent with the intent of the existing ACTION for an inoperable radiation monitoring instrumentation channel. Since this change only provides more explicit direction of the current interpretation of the existing specifications, this change is considered administrative.

A.3 The proposed Conditions and Required Actions will adequately cover all potential conditions for inoperable equipment in the system and as such, the indication that Specification 3.0.3 is not applicable is unnecessary. This is considered to be a change in presentation only and therefore an administrative change.

A.4 The technical content of this requirement was divided into two Surveillances. The majority of this Surveillance is performed as proposed SR 3.3.7.1.4, a LOGIC SYSTEM FUNCTIONAL TEST (LSFT). The LSFT verifies that each signal functions properly. The actual system functional test portion is performed in LCO 3.7.3 Surveillance Requirements. This will ensure that the entire system is tested with proper overlap.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 The current allowance that provides 4 hours to adjust an alarm setpoint to within its limit prior to declaring the channel inoperable has been deleted. When the setpoint is not within its allowable value, the channel will be declared inoperable immediately. This is an additional restriction on plant operation and is consistent with the BWR Standard Technical Specifications, NUREG-1434.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

M.2 Three new Control Room Emergency Filtration System Instrumentation Functions have been added: Reactor Vessel Water Level–Low Low, Level 2; Drywell Pressure–High; and Reactor Building Vent Exhaust Plenum Radiation–High. These instruments are the same as those used in the Secondary Containment Isolation Instrumentation Specification and automatically actuate the CREF System. Appropriate ACTIONS (ACTIONS B, C, and D) and Surveillance Requirements (SRs 3.3.7.1.1, 3.3.7.1.2, 3.3.7.1.3, and 3.3.7.1.4) have also been added, consistent with the BWR Standard Technical Specifications, NUREG-1434. This is an additional restriction on plant operation.

M.3 The Main Control Room Ventilation Radiation Monitor Function setpoint has been decreased to the proper Allowable Value. The new Allowable Value is based upon the most recent setpoint calculation. This is an additional restriction on plant operation.

M.4 The requirement to initiate and maintain operation of the Control Room Emergency Filtration (CREF) System in the pressurization mode with one or more radiation monitors inoperable has been deleted. The requirement allowed continued operation for an unlimited amount of time with both radiation monitors in a remote air intake inoperable, once the CREF System is placed in the pressurization mode. However, if a design basis LOCA occurs with the CREF System in the pressurization mode and makeup being provided through both remote intakes, the dose limits assumed in the accident analysis will be exceeded since one of the remote air intakes will be in the plume exposure pathway. Thus, the current requirements do not adequately compensate for inoperable radiation monitors; initiating and maintaining the CREF System in the pressurization mode will not have any impact on precluding the dose limits from being exceeded. The accident analysis assumes that the remote air intake radiation monitors are needed to ensure that the remote air intake in the plume exposure pathway is manually isolated. The monitors will provide indication as to which remote air intake is in the plume exposure pathway, and based on this indication, plant personnel will manually isolate the remote air intake in the plume exposure pathway. Isolation of this remote air intake is required to ensure the dose limits to the control room personnel are not exceeded. During the accident sequence, continued monitoring of the remote air intake radiation monitors is needed to provide indication as to when to shift the CREF System suction from one intake to the other intake. The accident analysis assumes that the CREF System is in the pressurization mode, with makeup provided through only one of the remote air intakes (after the initial determination is made by the operators, using the

TECHNICAL CHANGES - MORE RESTRICTIVE

M.4 (cont'd) radiation monitors, as to which remote air intake the plume is over and actions taken to isolate the remote air intake). Therefore, if a radiation monitor is not restored within 30 days or 7 days (depending upon whether a monitor is inoperable in one or both remote air intakes - see Comment L.3), or if all radiation monitors are inoperable, proposed Required Action F.1 will require both CREF subsystems to be declared inoperable (which will result in a unit shutdown per the CREF System Specification). In addition, if both radiation monitors on one remote air intake are inoperable, the associated remote air intake must now be closed within 1 hour (proposed Required Action E.1). With no indication of radiation levels at this intake, it is prudent to initially isolate the remote air intake during the time provided to restore one of the radiation monitors to OPERABLE status. This ensures that if an accident occurs while both radiation monitors are inoperable, the remote air intake is already isolated to preclude the dose limits from being exceeded if the unmonitored remote air intake is in the plume exposure pathway. In addition, a proposed Note to Required Action E.1 has also been added that requires entry into appropriate Conditions and Required Actions of LCO 3.7.3 if both remote air intakes are isolated. Since proposed LCO 3.0.6 could be interpreted to provide an allowance to not enter the ACTIONS of LCO 3.7.3 when the air intakes are isolated due to inoperable radiation monitors, this Note ensures that if both remote air intakes are isolated, the CREF System is declared inoperable and the ACTIONS of proposed LCO 3.7.3 taken immediately. These changes are additional restrictions on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 Alarm setpoints are an operational detail that is not directly related to the OPERABILITY of the instrumentation. These details are proposed to be relocated to plant procedures. The Allowable Value is the required limitation for the parameter and this value is retained in the Technical Specifications. Changes to the relocated alarm setpoints in procedures will be controlled by the provisions of 10 CFR 50.59.

LB.1 The CHANNEL FUNCTIONAL TEST Frequency is extended to 92 days. The drift data for this instrument (control room radiation monitor) has been reviewed and would support the extension without exceeding the Allowable Value. This Frequency has been shown to maintain an acceptable risk in accordance with previously conducted reliability analysis (GENE-770-06-1-A, December 1992). As required by the NRC Safety Evaluation Report accepting this generic reliability analysis (dated July 21, 1992), WNP-2 has confirmed that the logic design of the instrumentation is bounded by that analyzed in the reliability analysis and the conclusions

TECHNICAL CHANGES - LESS RESTRICTIVE

LB.1 (cont'd) of the analysis are applicable to the WNP-2 design. In addition, WNP-2 has confirmed that the instrument drift due to the extended Surveillance Frequency is already properly accounted for in the setpoint calculation methodology. (B)

"Specific"

L.1 This change limits the Applicability of the requirements for the system to during those operations which have potential to create a need for the system to operate. The omitted conditions are not considered as initiators for events which require the system and therefore the change does not impact safety. Thus, MODE 5 is deleted, while the conditions that could result in a potential for a radiation release in MODE 5, CORE ALTERATIONS, handling of irradiated fuel in the secondary containment, and operations with a potential for draining the reactor vessel, are maintained. In addition, footnote * has been deleted since it is redundant to MODES 1, 2, and 3. The main condenser air evacuation system is normally operated in MODES 1, 2, and 3, when the reactor could be pressurized. In MODES 4 and 5, the reactor is depressurized, thus the system would not be used to remove non-condensible radioactive gases released from the reactor coolant. (B)

L.2 The requirement to isolate the remote air intake if one of the two radiation monitors on the remote air intake is inoperable has been deleted. With one radiation monitor on a remote air intake inoperable, the other radiation monitor is fully capable of providing indication of radiation at the remote air intake. The purpose of the monitors is to provide indication of radiation at the remote air intake, and if radiation is detected above the specified setpoint, the plant personnel will isolate the associated remote air intake. Isolation of the associated remote air intake is not required until radiation exceeds the specified setpoint. It is overly conservative to isolate the associated remote air intake when indication is still available. This allowance is only provided for 7 days or 30 days, depending upon whether channels in one or both remote air intakes are inoperable (See Comment L.3 below for justification of the 30 day Completion Time). In addition, as described in Comment M.4 above, isolation of the remote air intake will occur within 1 hour when both radiation monitors are inoperable. (B)

L.3 With one or two radiation monitors inoperable on one remote air intake, the time allowed to restore the monitors has been extended from 7 days to 30 days. The function of the monitor is to provide indication as to whether or not the plume is over the respective remote air intake. The location of the remote air intakes is such that the plume cannot be over both remote air intakes at the same time. Therefore, the OPERABLE radiation monitors on the other remote air intake can provide indication as to what remote air intake the plume is covering. If the OPERABLE radiation monitors are indicating that the plume is over its respective remote air

TECHNICAL CHANGES - LESS RESTRICTIVE

L.3 (cont'd) intake, the other remote intake, which has no OPERABLE radiation monitors, cannot have the plume over it. Therefore, it is acceptable to extend the allowed outage time of radiation monitors on one remote air intake to 30 days, provided the other two radiation monitors on the other remote intake are OPERABLE. The remaining OPERABLE radiation detectors receive AC power from opposite divisions, thus if a loss of offsite power occurs, coincident with a LOCA and a failure of a diesel generator to start, one of the two detectors will remain energized and capable of providing indication to the operators. The proposed 30 day Completion Time is consistent with the 30 day Completion Time provided for PAM instrumentation. The radiation monitors are perform a similar function as a PAM instrumentation Type A variable; they provide indications so that the control room operating staff can take specified, preplanned, manually controlled actions for which no automatic control is provided, which are required for the Control Room Emergency Filtration System to accomplish its safety function. In addition, manual sampling of the remote air intake location would also provide the necessary information. The proposed 30 day Completion Time is provided in the dual Completion Times of proposed Required Action E.2. A 7 day Completion Time is provided (consistent with current Licensing Basis) if one or more radiation monitors are inoperable in both remote air intakes, and a 30 day Completion Time is provided if this is not the case.

(B)

Specification 3.3.8.1

INSTRUMENTATION

3/4.3.3 ~~EMERGENCY CORE COOLING SYSTEM ACTUATION~~ INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

LCO 3.8.1

3.3.3 The ~~emergency core cooling system (ECCS)~~ actuation instrumentation channels shown in Table 3.3.3-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.3-2.

APPLICABILITY: As shown in Table 3.3.3-1.

ACTION:

a. With an ~~ECCS~~ actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.3-2, declare the channel inoperable until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. With one or more ~~ECCS~~ actuation instrumentation channels inoperable, within ~~24~~ 1 hours take the ACTION required by Table 3.3.3-1.

c. With either ADS trip system "A" or "B" inoperable, restore the inoperable trip system to OPERABLE status:

1. Within 7 days, provided that the HPCS and RCIC systems are OPERABLE; otherwise,

2. Within 72 hours.

Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to less than or equal to 128 psig within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.3.3.1 Each ~~ECCS~~ actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.3.1-1.

SR 3.3.8.1.1 4.3.3.2 LOGIC SYSTEM FUNCTIONAL TESTS ~~and simulated automatic operation~~ of all channels shall be performed at least once per ~~18~~ 24 months.

4.3.3.3 The ECCS RESPONSE TIME of each ECCS trip function shall be demonstrated to be within the limit at least once per 18 months. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific ECCS trip system.

TABLE 3.3.3-1 (Continued)

A.1 LOP

~~EMERGENCY CORE COOLING SYSTEM ACTUATION~~ INSTRUMENTATION

ACTION STATEMENTS

ACTION 30 — With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement:

a. For one trip system, place the inoperable channel(s) and/or that trip system in the tripped condition within 1 hour* or declare the associated system inoperable.
b. For both trip systems, declare the associated system inoperable.

ACTION 31 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, place the inoperable channel in the tripped condition within 1 hour; restore the inoperable channel to OPERABLE status within 7 days or declare the associated system inoperable.

ACTION 32 — With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, declare the associated system inoperable.

ACTION 33 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, place the inoperable channel in the tripped condition within 1 hour.

ACTION 34 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, restore the inoperable channel to OPERABLE status within 8 hours or declare the associated ECCS inoperable.

ACTION 35 — With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, restore the inoperable channel to OPERABLE status within 24 hours or declare the associated AOS division inoperable.

ACTION 36 — With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, place the inoperable channel in the tripped condition within 1 hour* or declare the HPCS system inoperable.

ACTION 37 - With the number of OPERABLE channels less than the Total Number of Channels, declare the associated emergency diesel generator inoperable and take the ACTION required by Specification 3.8.1.1 or 3.8.1.2, as appropriate.

A.4

ACTION B

ACTION 38 - With the number of OPERABLE channels one less than the Total Number of Channels, place the inoperable channel in the tripped condition within 1 hour*, operation may then continue until performance of the next required CHANNEL FUNCTIONAL TEST.

M.1

L.3

Add proposed Required Action B.1

L.2

ACTION B

*The provisions of Specification 3.0.4 are not applicable.

A.5

B

B

See Discussion of Changes for ITS: 3.3.5.1, ECCS Instrumentation, in this section.

A.1 LOP

Table 3.3.8.1-1

TABLE 4.3.3.1-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST (SR 3.3.8.1.1)	CHANNEL CALIBRATION (SR 3.3.8.1.2)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
C. DIVISION 3 TRIP SYSTEM				
1. HPCS SYSTEM				
a. Reactor Vessel Water Level - Low Low, Level 2	S	Q	R	1, 2, 3, 4*, 5*
b. Drywell Pressure-High	N.A.	Q	R	1, 2, 3
c. Reactor Vessel Water Level-High, Level 8	S	Q	R	1, 2, 3, 4*, 5*
d. Condensate Storage Tank Level - Low	N.A.	Q	R	1, 2, 3, 4*, 5*
e. Suppression Pool Water Level - High	N.A.	Q	R	1, 2, 3, 4*, 5*
f. HPCS System Flow Rate-Low (Minimum Flow)	N.A.	Q	R	1, 2, 3, 4*, 5*
g. Manual Initiation	N.A.	R	N.A.	1, 2, 3, 4*, 5*
D. LOSS OF POWER				
1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)	N.A.	N.A.	R	1, 2, 3, 4**, 5**
2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage Division 1 and 2)	N.A.	M***	R	1, 2, 3, 4**, 5**
3. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage Division 3)	N.A.	N.A.	R	1, 2, 3, 4**, 5**

M.3 Add proposed Functions 1.b, 1.c, 1.d and 2.b

1.a and 2.a

1.e, 1.f, and 1.g

2.c and 2.d

M.2

L.9 add Proposed Note 2 to Surveillance Requirements

TABLE NOTATIONS

#Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 128 psig.

*When the system is required to be OPERABLE per Specification 3.5.2.

**Required when ESF equipment is required to be OPERABLE.

***The secondary time delay 3 second relays are exempt from this monthly testing. The secondary time delay relays associated with this logic will be functionally tested as part of the Logic System Functional Testing (Surveillance Requirement 4.3.3.2)

Applicability

Function 1.e SRs

See Discussion of Changes for ITS: 3.3.5.1, ECCS Instrumentation, in this section.

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Specification 3.3.8.1

DISCUSSION OF CHANGES
ITS: 3.3.8.1 - LOSS OF POWER INSTRUMENTATION

ADMINISTRATIVE

A.1 A new LCO has been written specifically for the Loss of Power (LOP) Instrumentation. The LOP Function from the current ECCS instrumentation LCO (3/4.3.3) is incorporated into this LCO. The LCO requires the instruments listed in proposed Table 3.3.8.1-1 to be OPERABLE, and the Table has the Appropriate Functions listed. Since this is an organizational change it is considered to be administrative.

A.2 This proposed change provides more explicit instructions for proper application of the ACTIONS for Technical Specification compliance. In conjunction with the proposed Specification 1.3 - "Completion Times," the Note ("Separate Condition entry is allowed for each....") provides direction consistent with the intent of the existing ACTION for an inoperable ECCS instrumentation channel. Since this change only provides more explicit direction of the current interpretation of the existing specifications, this change is considered administrative.

A.3 Since there is no required Loss of Power response time (in Table 3.3.3-3, which was deleted in Amendment 139, the response time was listed as "N.A."), the line item was removed to eliminate unnecessary requirements. As such, this deletion is considered administrative.

A.4 The format of the proposed Technical Specifications does not generally include providing "cross references." The existing references to the other Specifications serve no functional purpose, and their removal is purely an administrative difference in presentation.

A.5 The Specification 3.0.4 exception has been deleted since proposed LCO 3.0.4 contains this provision (allows continued operation once a channel is placed in the tripped condition). (B)

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 The time allowed for placing a channel in trip (i.e., essentially the requirement of current ACTION b) has been changed from 24 hours to 1 hour. In addition, the current ACTION 38 requirement to place the inoperable channel in Trip within 1 hour has been combined into current ACTION b (proposed ACTION A), therefore, the 1 hour allowance of ACTION 38 has been deleted. As stated in proposed ACTION A, the channel must now be tripped within 1 hour, instead of the current time allowed (up to

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 (cont'd) 25 hours). This is consistent with the BWR Standard Technical Specifications, NUREG-1434 and is an additional restriction on plant operation.

M.2 Current Technical Specifications require these instruments to be OPERABLE during MODES 4 and 5 only when ESF equipment is required to be OPERABLE. This is being changed to require them to be OPERABLE during MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment (which could be when the unit is defueled). This is consistent with the BWR Standard Technical Specifications, NUREG-1434 and is an additional restriction on plant operation.

M.3 Current Technical Specifications do not include Division 1 and 2 TR-S and Division 3 Loss of Voltage time delays included in the circuitry and do not separate the Degraded Voltage time delay for the Division 1 and 2 ESF 4160 V buses into the appropriate two separate time delays. Proposed Technical Specifications include these additional instruments in Table 3.3.8.1-1. This is consistent with the BWR Standard Technical Specifications, NUREG-1434 and is an additional restriction on plant operation. In addition, the current Specification only includes the Loss of Voltage instrumentation that starts the DG, disconnects the preferred source of offsite power (TR-S) and auto-transfers to the alternate source of offsite power (TR-B) if available, and load sheds the 4.16 kV ESF buses. The TR-S Loss of Voltage instrumentation will not disconnect the TR-B offsite circuit if the TR-B offsite circuit is connected to the 4.16 kV ESF bus when the loss of voltage occurs. The alternate source of offsite power, TR-B, has Loss of Voltage instrumentation that will disconnect it from the 4.16 kV ESF bus if connected. Therefore, two new Functions have been added, Functions 1.c and 1.d, that provide the requirements for the Division 1 and 2 TR-B Loss of Voltage instrumentation (TR-B only supplies power to Division 1 and 2). Appropriate ACTIONS have also been added when the instrumentation is inoperable. This is also an additional restriction on plant operation.

M.4 The Degraded Voltage and Degraded Voltage Time Delay Relay Functions setpoints have been decreased to the proper Allowable Values. The new Allowable Values are based upon the most recent setpoint calculations. These are additional restrictions on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 Trip setpoints are an operational detail that is not directly related to the OPERABILITY of the instrumentation. These details are proposed to be relocated to plant procedures. The Allowable

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.1 (cont'd) Value is the required limitation for the parameter and this value is retained in the Technical Specifications. Changes to the relocated trip setpoints in procedures will be controlled by the provisions of 10 CFR 50.59.

LA.2 The details relating to methods for performing the LOGIC SYSTEM FUNCTIONAL TEST are proposed to be relocated to the Bases. These details are not necessary to ensure the OPERABILITY of the loss of power instrumentation. The requirements of Specification 3.3.8.1 and the associated Surveillance Requirements are adequate to ensure the loss of power instruments are maintained OPERABLE. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LA.3 System design details are proposed to be relocated to the Bases. Details relating to system design (the total number of channels provided in the design, the number of channels required to generate a trip, and the types of relays used) are unnecessary in the LCO. These details are not necessary to ensure the OPERABILITY of the loss of power instrumentation. The requirements of Specification 3.3.8.1 and the associated Surveillance Requirements are adequate to ensure the loss of power instruments are maintained OPERABLE. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LA.4 The 120 V basis for the loss of power instrumentation trip setpoints and Allowable Values are proposed to be relocated to plant procedures. These trip setpoints and Allowable Values are duplicative of the 4160 V basis. There is only one instrument. It typically is connected to the 4160 V bus via a stepdown transformer, monitoring the bus at a 120 V "basis." The analytical setpoint is evaluated based on the 4160 V bus, and is therefore the value specified in the proposed Technical Specifications. The actual instrumentation design is not necessary for explicit reference in the proposed Technical Specifications (similar to main steam line high flow instrumentation, which actually monitors the trip setpoint based on differential pressure, not actual steam line flow). Changes to the relocated requirements in procedures will be controlled by the provisions of 10 CFR 50.59.

LD.1 The Frequency for performing the LOGIC SYSTEM FUNCTIONAL TEST of current Surveillance 4.3.3.2 (proposed SR 3.3.8.1.4) has been extended from 18 months to 24 months to facilitate a change to the WNP-2 maintenance cycle from 12 months to 24 months. The current conditions in the northwest require that WNP-2 shut down each spring for an annual maintenance and refueling outage. Currently, 13

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd) most of the current Surveillances that are required to be performed on an 18 month interval are performed annually because they must be performed while the plant is shut down. This has resulted in increased testing, with a resultant increase in cost and personnel exposure, with no comparable increase in reliability or safety. This change is being proposed to support limiting the amount of surveillance testing that must be performed each maintenance and refueling outage. The proposed change will allow this Surveillance to extend the Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2). This proposed change was evaluated in accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991. Reviews of historical maintenance and surveillance data have shown that this test normally passes the Surveillance at the current Frequency. An evaluation has been performed using this data, and it has been determined that the effect on safety due to the extended Surveillance Frequency will be small. In addition, the proposed 24 month Surveillance Frequency, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) does not invalidate any assumptions in the plant licensing basis. (B)

LF.1 This change revises the Technical Specification setpoints for proposed Section 3.3 instrumentation to reflect Allowable Values consistent with the philosophy of NUREG-1434. These Allowable Values (to be included in Technical Specifications) have been established consistent with the WNP-2 Instrument Setpoint Methodology. The Allowable Value selection evaluation used actual WNP-2 operating and surveillance trend information to ensure the validity of the evaluation input data. All changes to safety analysis limits, applied in the methodologies, were evaluated and confirmed as ensuring safety analysis licensing acceptance limits are maintained. All design limits, applied in the methodologies, were confirmed as ensuring that applicable design requirements of the associated systems are maintained. The methodologies used to derive the Allowable Values are based on combining the uncertainties of the associated channels. The methodologies used in the evaluation are consistent with the guidance of ISA Standard, SP67.04-1982, "Setpoints for Nuclear Safety-Related Instruments used in Nuclear Power Plants," which was approved for use by the NRC in RG 1.105, Revision 2, February 1986. Plant calibration procedures will ensure the assumptions regarding calibration accuracy are maintained. The proposed Allowable Values have been established from each design or safety analysis limit by accounting for instrument accuracy, calibration and drift uncertainties, environmental effects, power supply fluctuations, (B)

TECHNICAL CHANGES - LESS RESTRICTIVE

LF.1 (cont'd) as well as uncertainties related to process and primary element measurement accuracy using the WNP-2 Instrument Setpoint Methodology. The use of these methodologies for establishing Allowable Values ensures design or safety analysis limits are not exceeded in the event of transients or accidents and accounts for uncertainties and environmental conditions.

"Specific"

L.1 The current Technical Specifications require two Loss of Voltage channels for each division and three Division 1 and 2 Degraded Voltage channels (even though the Minimum Channels OPERABLE column requires two Degraded Voltage channels, ACTION 38 implies that three channels, as stated in the Total Number of Channels column, are required). The Division 1 and 2 TR-S and Division 3 Loss of Voltage logic is one-out-of-two and the Division 1 and 2 Degraded Voltage logic is two-out-of-three. The instrumentation is a support system to the 4160 V ESF buses and DGs, which themselves are support systems to the various systems they provide power to. It is overly conservative to require a support system to a support system to be single failure proof. The DGs and ESF buses are designed to meet the single failure criterion, i.e., one DG and associated ESF buses is assumed to fail in the accident analyses. Therefore, the proposed Technical Specifications only require one Division 1 and 2 TR-S and Division 3 Loss of Voltage channel per division and two Degraded Voltage channels per division to be OPERABLE. A single failure of any one of these required channels will only result in the loss of one DG and associated bus, which is no worse than the loss of a single DG and associated bus for any other reason (e.g., failure of DG breaker to function properly). In some instances, a specific Time Delay Function channel is associated with a specific Loss of Voltage or Degraded Voltage Function to provide the safety function. Therefore, Notes (a) and (b) to Table 3.3.8.1-1 have been added to ensure the safety function of the LOP instrumentation works as designed.

L.2 An additional Required Action is provided (proposed Required Action B.1) to require declaring the DG inoperable and taking the appropriate actions in the associated DG Specification if a channel is not tripped within 1 hour. Currently, the ACTIONS appear to require a Specification 3.0.3 entry if the channel is not tripped, which would result in an immediate shutdown. Since this instrument is the start signal for the DGs (i.e., it supports DG OPERABILITY), the appropriate action would be to declare the DG inoperable. The current requirements are overly restrictive, in

TECHNICAL CHANGES - LESS RESTRICTIVE

L.2 (cont'd) that if the diesel were inoperable for other reasons, a 72 hour restoration time is provided; yet currently if an instrument is inoperable but the diesel is otherwise fully OPERABLE, an immediate shutdown is required.

L.3 The requirement for performing the CHANNEL FUNCTIONAL TEST is included in proposed SR 3.3.8.1.1. It is possible that the test would not be able to be performed with an inoperable channel, and a plant shutdown would be required due to the inability to perform the required Surveillance. However, this restriction on continued operation need not be specified as an ACTION (as is the case in existing ACTION 38); it exists inherently as a result of the CHANNEL FUNCTIONAL TEST requirement. In some cases, it will be possible to perform the test with a channel inoperable (using the allowance of proposed LCO 3.0.5). Thus, deleting the requirement to operate only until the next CHANNEL FUNCTIONAL TEST will allow continued operation with an inoperable, tripped channel for a longer period of time than is currently allowed. This is acceptable since placing the channel in trip conservatively compensates for the inoperable status, restores the single failure capability, and provides the required initiation capability of the instrumentation. Therefore, it is not necessary to limit the time the channel is allowed to be tripped. (B)

L.4 This change proposes to add a Note (Note 2) to the Surveillance Requirements that will allow a 2 hour delay from entering into the associated Conditions and Required Actions for a channel placed in an inoperable status solely for performance of required Surveillances provided the associated Function maintains initiation capability for two DGs and associated 4.16 kV ESF buses. The loss of Function is acceptable in this case since only two of the three DGs are required to start within the required time and only two of the three 4.16 kV buses are required to be energized to meet accident analysis assumptions. The short period of time (2 hours) in this condition will have no appreciable impact on risk. Also, upon completion of the Surveillance, or expiration of the 2 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition must be entered and Required Actions taken. (B)

Specification 3.3.8.2

ELECTRICAL POWER SYSTEMS

REACTOR PROTECTION SYSTEM ELECTRIC POWER MONITORING

LIMITING CONDITION FOR OPERATION

LCO 3.3.8.2

3.8.4.4 Two RPS electric power monitoring channels for each inservice RPS MG set or alternate source shall be OPERABLE.

APPLICABILITY: At all times. — L.1 — that supports equipment required to be OPERABLE

B

ACTION:

a. With one RPS electric power monitoring channel for an inservice RPS MG set or alternate power supply inoperable, restore the inoperable power monitoring channel to OPERABLE status within 72 hours or remove the associated RPS MG set or alternate power supply from service. — A.1

ACTION A

b. With both RPS electric power monitoring channels for an inservice RPS MG set or alternate power supply inoperable, restore at least one electric power monitoring channel to OPERABLE status within 30 minutes or remove the associated RPS MG set or alternate power supply from service. — A.1

ACTION B — A.2 — add proposed ACTIONS — 1 hour — L.2

M.1 — add proposed ACTIONS Done

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SURVEILLANCE REQUIREMENTS — add proposed Surveillance Requirements Note — L.3

A

4.8.4.4 The above specified RPS power monitoring channels instrumentation shall be determined OPERABLE:

SR 3.3.8.2.1 a. By performance of a CHANNEL FUNCTIONAL TEST each time the plant is in COLD SHUTDOWN for a period of more than 24 hours, unless performed within the previous 6 months.

Note in SR 3.3.8.2.1

SR 3.3.8.2.2, SR 3.3.8.2.3, SR 3.3.8.2.4, SR 3.3.8.2.2, SR 3.3.8.2.3, SR 3.3.8.2.4, SR 3.3.8.2.2, SR 3.3.8.2.3

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

LF.1 — 3.3.8

1. Overvoltage ≤ 132 VAC — 110.8 — M.2
2. Undervoltage ≥ 108 VAC, and
3. Underfrequency ≥ 57 Hz

for alternate power supply only

with time delay set to ≤ 4 seconds — M.3

with time delay set to zero — for RPS MG set power supply only

DISCUSSION OF CHANGES
ITS: 3.3.8.2 - RPS ELECTRIC POWER MONITORING

ADMINISTRATIVE

A.1 The revised presentation of ACTIONS (based on the BWR Standard Technical Specifications, NUREG-1434) is proposed to not explicitly detail options of "restore...to OPERABLE status." This action is always an option, and is implied in all ACTIONS. Omitting this action is editorial.

A.2 A new ACTION is provided (ACTION C) that requires a shutdown if the Required Actions are not met. This action is functionally equivalent to the current LCO 3.0.3 (although current LCO 3.0.3 does provide an additional 1 hour to commence the shutdown). Therefore, this change is considered to be a presentation preference and is administrative.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 Two new ACTIONS are provided if the Required Actions of Condition A or B are not met. ACTION D requires action to be initiated to restore the assembly to OPERABLE status (Required Action D.1) or to isolate the Residual Heat Removal (RHR) Shutdown Cooling (SDC) System (Required Action D.2), and ACTION E requires insertion of any withdrawn control rods in cells containing fuel. These actions place the reactor in the least reactive condition and ensures the safety function of the RPS and isolation system will not be required. (B)

M.2 The undervoltage Allowable Value has been changed from $\geq$ 108 volts to $\geq$ 110.8 volts. This new Allowable Value is based on the most recent setpoint calculations, which ensure the RPS and RPS bus powered equipment receive adequate voltage to operate properly. This change is an additional restriction on plant operation.

M.3 Time delay setting requirements have been added for the overvoltage, undervoltage, and underfrequency protective devices of the RPS MG set and alternate power supply electric power monitoring assemblies. Currently, no maximum setting is provided. These devices have adjustable time delay settings. The new Allowable Values are zero for the RPS MG set power supply electric power monitoring assemblies and $\leq$ 4 seconds for the alternate power supply electric power monitoring assemblies. The Allowable Values are based on the current setpoint methodology and ensure that the devices trip to protect the equipment powered by the RPS MG set or alternate power supply. These Allowable Values are also consistent with the current settings of the devices. This change is an additional restriction on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LF.1 This change revises the Technical Specification setpoints for proposed Section 3.3 instrumentation to reflect Allowable Values consistent with the philosophy of NUREG-1434. These Allowable Values (to be included in Technical Specifications) have been established consistent with the WNP-2 Instrument Setpoint Methodology. The Allowable Value selection evaluation used actual WNP-2 operating and surveillance trend information to ensure the validity of the evaluation input data. All changes to safety analysis limits, applied in the methodologies, were evaluated and confirmed as ensuring safety analysis licensing acceptance limits are maintained. All design limits, applied in the methodologies, were confirmed as ensuring that applicable design requirements of the associated systems are maintained. The methodologies used to derive the Allowable Values are based on combining the uncertainties of the associated channels. The methodologies used in the evaluation are consistent with the guidance of ISA Standard, SP67.04-1982, "Setpoints for Nuclear Safety-Related Instruments used in Nuclear Power Plants," which was approved for use by the NRC in RG 1.105, Revision 2, February 1986. Plant calibration procedures will ensure the assumptions regarding calibration accuracy are maintained. The proposed Allowable Values have been established from each design or safety analysis limit by accounting for instrument accuracy, calibration and drift uncertainties, environmental effects, power supply fluctuations, as well as uncertainties related to process and primary element measurement accuracy using the WNP-2 Instrument Setpoint Methodology. The use of these methodologies for establishing Allowable Values ensures design or safety analysis limits are not exceeded in the event of transients or accidents and accounts for uncertainties and environmental conditions.

(B)

"Specific"

L.1 With no control rods withdrawn from core cells containing fuel assemblies and both RHR SDC suction isolation valves not open, there is no need for the RPS and the RPS bus powered components to perform their function and therefore, there is no need to require their protection. Therefore, the Applicability has been changed to only include those MODES or Conditions when the RPS and the RPS bus powered components are required. In addition, Special Operations LCO 3.10.4 will allow a single control rod to be withdrawn in MODE 4 by allowing the Reactor Mode Switch to be in the Refuel position. Therefore, the RPS Electric Power Monitoring requirements for MODE 4 operation have been included in LCO 3.10.4.

(A)

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.2 The allowed out of service time for two inoperable assemblies is extended to 1 hour to provide sufficient time for the plant personnel to take corrective actions. The time extension for two inoperable assemblies is minimal but necessary to allow consideration of plant conditions, available personnel and the appropriate actions.

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

Specification 3.4.1

REACTOR COOLANT SYSTEM

RECIRCULATION LOOP FLOW

LIMITING CONDITION FOR OPERATION

LCO 3.4.1

3.4.1.3 Recirculation loop flow mismatch shall be maintained within:

SR3.4.1.1

a. 5% of rated recirculation flow with core flow greater than or equal to 70% of rated core flow.

b. 10% of rated recirculation flow with core flow less than 70% of rated core flow.

1.B

APPLICABILITY: OPERATIONAL CONDITIONS ~~1~~ and ~~2~~ (A.2) during two recirculation loop operation.

ACTION:

ACTION E

With the recirculation loop flows different by more than the specified limits, either:

a. Restore the recirculation loop flows to within the specified limit within 2 hours, or (A.9)

b. Declare the recirculation loop with the lower flow not in operation and take the ACTION required by Specification 3.4.1.1. (A.10)

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SURVEILLANCE REQUIREMENTS

add proposed SR3.4.1.1 Note (L.3)

SR3.4.1.1 4.4.1.3 Recirculation loop flow mismatch shall be verified to be within the limits at least once per 24 hours.

*See Special Test Exception 3.10.4. (A.2)

1.B

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.2 (cont'd) philosophy of the BWR Standard Technical Specifications, NUREG-1434, which is to not be overly prescriptive in the Technical Specifications. In addition, these requirements are not necessary for inclusion in Technical Specifications since proposed Required Actions C.1 and D.1 require exiting the associated Regions within a limited period of time. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LA.3 The details relating to operational limits during single recirculation loop operation are proposed to be relocated to plant procedures. The single loop operation flow rate is considered an operational limit since it is not directly related to the ability of the system to perform its safety analysis functions. The flow rate is limited only to restrict reactor vessel internals vibration to within acceptable limits. These requirements are oriented toward maintaining long term OPERABILITY of the recirculation loops and do not necessarily have an immediate impact on their OPERABILITY. Changes to the relocated requirements in plant procedures will be controlled by the provisions of 10 CFR 50.59.

Details relating to operational controls during single recirculation loop operation are proposed to be relocated to the FSAR. Operation of the flow control system in the local manual mode is the normal manner in which flow is controlled when in two loop operation. Thus, the flow control system is normally already in the proper mode for single loop operation; there is no need to place it in the proper mode since it is already in the proper mode. It also is not related to the ability of the system to perform its safety function. The system operation is described in the FSAR. Changes to the FSAR are controlled by the provisions of 10 CFR 50.59.

LA.4 The Operating Region Limits Figures of current Specifications 3.2.6, 3.2.7, 3.2.8, and 3.4.1.1 are proposed to be relocated to the COLR. These Figures are more appropriately located in the COLR since they are cycle-specific. This is consistent with Generic Letter 88-16, which allows cycle-specific thermal limits to be relocated to the plant-controlled COLR. The current COLR requirements in Specification 6.9.3.2.15 (proposed Specification 5.6.5.b.15) provides the NRC-approved analytical methods to determine the limits provided in the power-to-flow map. Any change to the analytical methods would require NRC approval prior to implementation. Therefore, there is no need to specify the power-to-flow map in the Technical Specifications; maintaining the map in the COLR is adequate. Changes to the COLR will be controlled by the provisions of the COLR change process described in Chapter 5 of the Technical Specifications. 1B

DISCUSSION OF CHANGES
ITS: 3.4.7 - RCS PRESSURE ISOLATION VALVE (PIV) LEAKAGE

ADMINISTRATIVE

A.1 The current test pressure has been changed from 950 ± 10 psig to 1035 psig. The current pressure is the test pressure at which the Surveillance is performed. Once complete, the observed leakage is adjusted to the leakage at the maximum pressure differential, which is 1035 psig (the proposed test pressure). This is in accordance with the applicable ASME Codes. Therefore, this change is considered administrative in nature since the actual requirements are not affected.

A.2 The proposed ACTIONS include two Notes. The first Note ("Separate Condition entry is allowed for each flow path") provides explicit instructions for proper application of the ACTIONS for Technical Specification compliance. In conjunction with the proposed Specification 1.3 - "Completion Times," this Note provides direction consistent with the intent of the existing ACTIONS for inoperable PIVs. The second Note facilitates the use and understanding of the intent to consider any system affected by inoperable PIVs, which is to have its ACTIONS also apply if it is determined to be inoperable. With the proposed LCO 3.0.6, this intent would not necessarily apply. This clarification is consistent with the intent and interpretation of the existing Technical Specifications, and is therefore considered an administrative presentation preference.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

None

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The list of pressure isolation valves (PIVs) are proposed to be relocated to the Licensee Controlled Specifications Manual. The listing of valves which are subject to the RCS PIV Leakage Specification are related to design and are not necessary for ensuring PIV leakage is maintained within limits. Specification 3.4.7 requires the leakage from each RCS PIV to be within limits. These requirements are adequate for ensuring PIV leakage is maintained within limits for the required valves. This change is also consistent with Generic Letter 91-08, which allowed lists of components to be relocated to plant controlled documents. Changes to the Licensee Controlled Specification Manual will be controlled by the provisions of 10 CFR 50.59.

ADMINISTRATIVE (continued)

A.5 The requirement to verify the vessel flange and head flange temperature within 30 minutes prior to tensioning of the head bolting studs has been deleted. This requirement is duplicative of current Specification 4.0.1 and proposed SR 3.0.1, which requires the Surveillance to be current when in the applicable MODE or condition. Proposed SR 3.0.1 (current Specification 4.0.3) also states that failure to meet the Surveillance constitutes failure to meet the LCO, which would then require the ACTIONS of the LCO to be taken. The ACTIONS for this LCO require immediate action to be taken to restore the limit. Therefore, this effectively ensures that the Applicability of this SR (as stated in the Note to the SR) is not entered with the Surveillance not current. Therefore, this change is considered administrative. (B)

A.6 Thermal stresses on vessel components are dependent upon the temperature difference between the idle loop coolant and the RPV coolant. Proposed SR 3.4.12.4 and SR 3.4.12.6 ensure the temperature difference between the idle loop and the RPV coolant is acceptable. The requirements to monitor the temperature difference between an idle loop and an operating loop are unnecessary and have been deleted since they are redundant to the loop-to-coolant requirement of proposed SR 3.4.12.4 and SR 3.4.12.6. However, the loop-to-coolant temperature check may use the operating loop temperature as representative of "coolant temperature."

A.7 These requirements have been combined into the RCS P/T Limits Specification, with the words "and the recirculation loop temperature requirements" added to the proposed LCO statement. The actual description of the requirements is found in proposed SRs 3.4.12.3 and 3.4.12.4. The limits are in the PTLR, as described in comment LA.1. As such, this change is administrative.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 A specific Completion Time for the engineering evaluation and determination is proposed. The proposed time of 72 hours is considered reasonable for operation in MODES 1, 2, and 3 because the limits represent controls on long term vessel fatigue and usage factors. In conditions other than MODES 1, 2, and 3, the proposed time (prior to entering MODE 2 or 3) would prevent entry in the operating MODES which is consistent with the current LCO 3.0.4.

TECHNICAL CHANGES - MORE RESTRICTIVE

M.2 The ACTIONS required to be taken when a recirculation pump is started without having met the temperature requirements have been changed. Currently, the ACTION only states to suspend the startup of a recirculation loop. This however, does not provide an action if the loop is already operating. Proposed ACTIONS A, B, and C now require an engineering evaluation to be performed to ensure continued operation is acceptable. This is an additional restriction on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The specific limits for Reactor Coolant System pressure and temperature, and recirculation loop temperatures have been relocated to the PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR). LCO 3.4.12 requires the limits in the PTLR to be maintained. In addition, the requirements of Specification 5.6.6 provide regulatory controls over the limits proposed to be relocated. As a result, the proposed relocated limits are not required to be included in the Technical Specifications to ensure RCS pressure and temperature are maintained within required limits. Changes to the PTLR will be controlled by the provisions of the proposed PTLR controls described in Chapter 5 of the Technical Specifications.

LA.2 The details relating to the basis for the THERMAL POWER and recirculation flow limitations in current Surveillance 4.4.1.1.2 (i.e., final values were determined during Startup Testing based upon actual THERMAL POWER and recirculation loop flow which will sweep the cold water from the vessel bottom head preventing stratification) are proposed to be relocated to the Bases. These details are not necessary to ensure the Surveillance Requirement is performed within the required limitations since the actual limits are still being maintained in the proposed Surveillance Requirements (SR 3.4.12.5 and SR 3.4.12.6). Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LA.3 The details relating to operational limits during single recirculation loop operation are proposed to be relocated to plant controlled documents. The single loop flow rate is considered an operational limit since it is not directly related to the ability of the system to perform its safety analysis functions. The flow rate is limited only to restrict reactor vessel internals vibration to within acceptable limits. These requirements are oriented toward maintaining long term OPERABILITY of the recirculation loops and do not necessarily have an immediate impact on their OPERABILITY. Changes to the relocated requirements in plant procedures will be controlled by the provisions of the 10 CFR 50.59.

3/4.5 EMERGENCY CORE COOLING SYSTEMS

3/4.5.1 ECCS - OPERATING

LIMITING CONDITION FOR OPERATION

LCO 3.5.1

3.5.1 ECCS divisions 1, 2, and 3 shall be OPERABLE with:

a. ECCS division 1 consisting of:

1. The OPERABLE low pressure core spray (LPCS) system with a flow path capable of taking suction from the suppression chamber and transferring the water through the spray sparger to the reactor vessel. (LA.1)

2. The OPERABLE low pressure coolant injection (LPCI) subsystem "A" of the RHR system with a flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel. (LA.1)

3. Seven (A.6, SIX) OPERABLE ADS valves. (B)

b. ECCS division 2 consisting of:

1. The OPERABLE low pressure coolant injection (LPCI) subsystems "B" and "C" of the RHR system each with a flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel. (LA.1)

2. Seven (A.6, Six) OPERABLE ADS valves. (B)

c. ECCS division 3 consisting of the OPERABLE high pressure core spray (HPCS) system with a flow path capable of taking suction from the suppression chamber and transferring the water through the spray sparger to the reactor vessel. (LA.1)

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2*, and 3*. (A.1)

*The ADS is not required to be OPERABLE when reactor steam dome pressure is less than or equal to 128 (150) psig. (L.2)

#See Special Test Exception 3.10.6 (A.1)

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EMERGENCY CORE COOLING SYSTEMS

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

ACTION C 2) With the LPCS system inoperable and either LPCI subsystems "B" or "C" inoperable, restore at least the inoperable LPCS system or the inoperable LPCI subsystem "B" or "C" to OPERABLE status within 72 hours → 7 days — L.3

ACTION D 3) Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours*. A.3

e. For ECCS divisions 1 and 2, provided that ECCS division 3 is OPERABLE and divisions 1 and 2 are otherwise OPERABLE: — A.2

ACTION E 1. With ~~two~~ one A.6 A.6 of the above required ADS valves inoperable, restore ~~the one~~ inoperable ADS valve to OPERABLE status within 14 days or be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to ≤ ~~128~~ 150 psig within the next 24 hours. — L.2 — B

ACTION G 2. With ~~three~~ two A.6 or more of the above required ADS valves inoperable, be in at least HOT SHUTDOWN within 12 hours and reduce reactor steam dome pressure to ≤ ~~128~~ 150 psig within the next 24 hours. — L.2 — B

f. In the event an ECCS system is actuated and injects water into the reactor coolant system, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date. The current value of the useage factor for each affected safety injection nozzle shall be provided in this Special Report whenever its value exceeds 0.70. — L.4

L.5 add proposed ACTION C for the HPCS system and one ECCS injection subsystem inoperable, and proposed ACTION F

*Whenever two or more RHR subsystems are inoperable, if unable to attain COLD SHUTDOWN as required by this ACTION, maintain reactor coolant temperature as low as practical by use of alternate heat removal methods. — A.3

add proposed ACTION H — A.2

ADMINISTRATIVE

A.5 (cont'd) R.A. Pinelli (BWROG), dated December 28, 1994, required that the utility commit to certain additional requirements and state this in the plant specific license amendment. WNP-2 has committed to these additional requirements. This evaluation will be documented in a 50.59 evaluation that deletes these instruments from the current WNP-2 ECCS RESPONSE TIME requirements. The evaluation will be performed in accordance with the 50.59 process since the actual response times have been removed from WNP-2 TS and placed under WPPSS control as documented in the NRC SER documented in Technical Specification Amendment 139. This evaluation will be complete prior to the issuance of an NRC SER for the WNP-2 ITS submittal. Therefore, this change is considered administrative.

A.6 The number of ADS valves required to be OPERABLE has been reduced from seven to six, since the current ACTIONS (ACTION e.1 and e.2) allow one ADS valve to be inoperable indefinitely. Current ACTIONS e.1 and e.2 have also been revised to reflect this change. This change is based on analysis summarized in NEDC-32115P, Washington Public Power Supply System Nuclear Project 2 SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis, Revision 2, dated July 1993. This analysis demonstrates adequate core cooling is provided during a small break LOCA and a simultaneous HPCS diesel generator failure (limiting LOCA) with two of the seven ADS valves out-of-service. This change reflects the credit provided through the use of NRC approved methods for calculating more realistic (yet conservative) peak cladding temperatures during accident situations. The above referenced document was reviewed and accepted by the NRC as documented in a letter from J.W. Clifford (NRC) to J.V. Parrish (WPPSS), "Issuance of Amendment for the Washington Public Power Supply System Nuclear Project No. 2 (TAC Nos. M87076 and M88625)," dated 05/02/95. This letter documented the allowance of current ACTIONS e.1 and e.2 (i.e., that one ADS valve can be inoperable indefinitely. Therefore, this change is considered administrative. (B)

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 A new requirement to verify the ADS accumulator backup compressed gas system is automatically aligned on an actual or simulated signal has been added as part of the overall ADS system functional test. This requirement is reflected in the Bases for proposed SR 3.5.1.6. This is an additional restriction on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The details relating to system OPERABILITY (in this case that the ECCS subsystems shall have flow paths capable of taking suction from the suppression chamber and transferring water to the reactor vessel) are proposed to be relocated to the Bases. The details for system OPERABILITY are not necessary in the LCO. The definition of OPERABILITY suffices. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LA.2 The details relating to methods for performing Surveillances are proposed to be relocated to the Bases. These details are not necessary to ensure the OPERABILITY of the ECCS subsystems. The requirements of Specification 3.5.1, ECCS-Operating, and the associated Surveillance Requirements are adequate to ensure the ECCS subsystems are maintained OPERABLE. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LC.1 The ADS accumulator backup compressed gas system pressure alarm instrumentation does not necessarily relate directly to ADS OPERABILITY. The BWR Standard Technical Specifications, NUREG-1434, does not specify alarm-only equipment to be OPERABLE to support OPERABILITY of a system or component. Control of the availability of, and necessary compensatory activities if not available, for indication instruments, monitoring instruments, and alarms are addressed by plant operational procedures and policies. Therefore, this instrumentation, along with the supporting Surveillances, are proposed to be relocated to plant procedures. Changes to the relocated requirements in plant procedures will be controlled by the provisions of 10 CFR 50.59.

LC.2 Current Specification 4.5.1.e.3.d requires a verification of the nitrogen capacity in at least two accumulator bottles per division within the backup compressed gas system. This requirement was required as part of the original licensing basis for the ADS System, as documented in a WPPSS letter from G.C. Sorensen (WPPSS) to A. Schwencer (NRC) dated September 23, 1983. In this letter, it was stated that the method used to determine a full bottle condition will be the responsibility of WPPSS. Based on previous discussions with the NRC documented in an NRC letter from A. Schwencer to R.L. Ferguson dated December 21, 1982, a method acceptable to the NRC is to calibrate the installed accumulator pressure gauges. This is the method WNP-2 has chosen to comply with this Surveillance Requirement. The calibration of the ADS accumulator backup compressed gas system pressure instrumentation does not necessarily relate directly to ADS OPERABILITY. The BWR Standard Technical Specifications, NUREG-1434, does not specify indication-only equipment to be OPERABLE to support OPERABILITY of a system or component. Control of the availability of, and necessary compensatory activities if not available, for indication

TECHNICAL CHANGES - LESS RESTRICTIVE

LC.2 (cont'd) instruments, monitoring instruments, and alarms are addressed by plant operational procedures and policies. The proposed Technical Specifications continue to include a requirement to ensure accumulator pressure is within the required limits (proposed SR 3.5.1.3). Therefore, this Surveillance Requirement is proposed to be relocated to plant procedures. Changes to the relocated requirements in plant procedures will be controlled by the provisions of 10 CFR 50.59.

LD.1 The Frequencies for performing current Surveillances 4.5.1.c, 4.5.1.d, 4.5.1.e.3.a, 4.5.1.e.3.b, and 4.3.3.3 (proposed SRs 3.5.1.5, 3.5.1.6, 3.5.1.7, and 3.5.1.8) have been extended from 18 months to 24 months to facilitate a change to the WNP-2 maintenance cycle from 12 months to 24 months. The current conditions in the northwest require that WNP-2 shut down each spring for an annual maintenance and refueling outage. Currently, most of the current Surveillances that are required to be performed on an 18 month interval are performed annually because they must be performed while the plant is shut down. This has resulted in increased testing, with a resultant increase in cost and personnel exposure, with no comparable increase in reliability or safety. This change is being proposed to support limiting the amount of surveillance testing that must be performed each maintenance and refueling outage. The proposed change will allow these Surveillances to extend their Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2). This proposed change was evaluated in accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991. Reviews of historical maintenance and surveillance data have shown that these tests normally pass their Surveillances at the current Frequency. An evaluation has been performed using this data, and it has been determined that the effect on safety due to the extended Surveillance Frequency will be small. In addition, the proposed 24 month Surveillance Frequencies, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) do not invalidate any assumptions in the plant licensing basis.

"Specific"

L.1 Not used. 1B

L.2 The pressure at which ADS is required to be OPERABLE is increased from 128 psig to 150 psig to provide consistency of the OPERABILITY requirements for all ECCS and RCIC equipment. Small

TECHNICAL CHANGES - LESS RESTRICTIVE

L.2 (cont'd) break loss of coolant accidents at low pressures (i.e., between 128 psig and 150 psig) are bounded by analyses performed at higher pressures. The ADS is required to operate to lower the pressure sufficiently so that the low pressure coolant injection (LPCI) and core spray (LPCS) systems can provide makeup to mitigate such accidents. Since these systems can begin to inject water into the reactor pressure vessel at pressures well above 150 psig (222 psid, steam dome pressure to drywell pressure, and steam dome pressure < 336 psig for LPCI and 285 psid, steam dome pressure to drywell pressure, and steam dome pressure < 336 psig for LPCS), there is no safety significance in the ADS not being OPERABLE between 128 psig and 150 psig.

L.3 The restoration times for two inoperable low pressure ECCS subsystems and one inoperable low pressure ECCS subsystem have been extended from 72 hours to 7 days and from 7 days to 14 days, respectively. The 72 hour extension to 7 days is for two inoperable LPCI subsystems or an inoperable LPCI subsystem and an inoperable LPCS System combination. The 7 day extension to 14 days is for an inoperable LPCI subsystem or LPCS System. This is based on a reliability study (GE-NE-A0005809-01, September 1994) that determined this change did not significantly reduce overall plant safety. This study utilized reliability based methodology that has previously been used and approved by the NRC in numerous BWROG submitted topical reports (e.g., "Technical Specification Improvement Analyses for BWR Reactor Protection System," NEDC-30851P-A, March 1988). The current WNP-2 IPE mode ("WNP-2 Individual Plant Examination Main Report," WPPSS-FTS-133, Revision 1, July 1994) was used as the basis for developing event tree and fault tree models to evaluate and verify the restoration time changes. This data was also used to analyze the impact of the restoration time change. The study evaluated numerous surveillance test interval and restoration time changes; the ECCS systems and subsystems restoration time extensions were only part of these changes. The results of the study showed that if all the changes evaluated were made, the change to the total loss of water injection function frequency increases only 6% above the base case (this equates to an increase of 8.0E-7 per year). This value is below the threshold for concern as established in NEDC-30936P-A, December 1988, which evaluated ECCS instrumentation TS changes and has been approved by the NRC.

L.4 The requirement to submit a Special Report for ECCS actuation and injection is adequately addressed by 10 CFR 50.73(a)(2)(iv). This CFR section requires an LER to be submitted for any event or condition that resulted in manual or automatic ECCS "actuation." Therefore, this LER will cover any "actuation and injection" as stipulated by the Special Report. This LER is required to be submitted within 30 days which also meets the Special Report requirement of 90 days. The necessary actuation cycle information

TECHNICAL CHANGES - LESS RESTRICTIVE

L.4 (cont'd) for WNP-2 will be controlled by plant procedures. Regulations provide sufficient control of these provisions for their removal from Technical Specifications.

L.5 Two new ACTIONS are being added to LCO 3.5.1: (1) for the condition of one ADS valve inoperable coincident with one low pressure ECCS injection/spray system (proposed ACTION F), and (2) for the condition of HPCS inoperable coincident with one low pressure coolant injection subsystem (covered by proposed ACTION C). The current Technical Specifications require entry into LCO 3.0.3 for these conditions, implying that the plant is outside design basis. The analysis summarized in FSAR Sections 6.3.3 and 15.F.6.5 demonstrates that adequate core cooling is provided by the OPERABLE HPCS or ADS System and the remaining OPERABLE low pressure injection/spray systems. However in both conditions the redundancy has been reduced such that another single failure may not maintain the ability to provide adequate core cooling. Proposed ACTION F requires a restrictive Completion Time of 72 hours since both a high pressure (ADS) and low pressure subsystem are inoperable. This Completion Time is based on a reliability study (Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975) and has been found to be acceptable through operating experience. Proposed ACTION C is similar to having two ECCS low pressure injection/spray systems inoperable. Therefore, the same allowable outage time of 7 days has been assigned to restore either the inoperable HPCS or LPCI subsystem.

L.6 A Note clarifying the alignment requirements of the LPCI subsystems has been included for proposed SR 3.5.1.2. The Note allows operation of one or more of the RHR subsystems in the shutdown cooling mode during MODE 3, if necessary, and clarifies that the subsystems are still considered OPERABLE for the LPCI mode. Because manual valve positioning, required for this mode of operation, removes the capability of the subsystems to respond automatically, the subsystems would be considered inoperable without this Note. Although no specific analysis of this condition has been performed, the allowance provided by the Note is acceptable because the return to OPERABILITY entails only the repositioning of valves, either remote or locally, and the energy requiring dissipation in MODE 3, below 135 psig, is considerably less than that at 100% power with normal operating temperature and pressure. Further, because of the low probability of an event requiring an ECCS and the certain need for shutdown cooling, it is considered appropriate to have the subsystems aligned for decay heat removal.

L.7 The phrase "actual or," in reference to the automatic initiation signal, has been added to the Surveillance Requirement for verifying that each ECCS subsystem actuates on an automatic initiation signal. This allows satisfactory automatic system initiations to be used to fulfill the Surveillance Requirements.

TECHNICAL CHANGES - LESS RESTRICTIVE

L.7 (cont'd) OPERABILITY is adequately demonstrated in either case since the ECCS subsystem itself cannot discriminate between "actual" or "simulated" signals.

L.8 Current Surveillance 4.5.1.e.1 (proposed SR 3.5.1.3) is being modified to require the ADS accumulator backup compressed gas system pressure to be an "average" instead of each individual bottle being required to meet the pressure limit. The bottles all have the same capacity. The associated analysis demonstrates that a 30 day nitrogen supply is available if the required bottles have an average pressure of 2200 psig. Therefore, it is not necessary for each bottle to have a pressure of 2200 psig.

EMERGENCY CORE COOLING SYSTEMS

SURVEILLANCE REQUIREMENTS

A.4

SR 3.5.2.3
SR 3.5.2.4
SR 3.5.2.5
SR 3.5.2.6

4.5.2.1 At least the above required ECCS divisions shall be demonstrated OPERABLE per Surveillance Requirement 4.5.1.

SR3.5.2.1.b

4.5.2.2 The HPCS system shall be determine OPERABLE at least once per 12 hours by verifying the condensate storage tank required volume when the condensate storage tank is required to be OPERABLE per Specification 3.5.2.e.

B

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EMERGENCY CORE COOLING SYSTEMS

3/4.5.3 SUPPRESSION CHAMBER

LIMITING CONDITION FOR OPERATION

3.5.3 The suppression chamber shall be OPERABLE:

a. In OPERATIONAL CONDITIONS 1, 2, and 3 with a contained water volume of at least 127,197 ft³, equivalent to a level of 30 ft 9 3/4 in.

A.5 Moved to LCO 3.6.2.2

b. In OPERATIONAL CONDITIONS 4 and 5* with a contained water volume of at least 127,197 ft³, equivalent to a level of 30 ft 9 3/4 in, except that the suppression chamber level may be less than the limit or may be drained provided that:

SR 3.5.2.1
SR 3.5.2.2.a

L.2 18-ft 6 inche

L.4

L.2

ACTION B

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

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

L.3

3. The condensate storage tank contains at least 135,000 available gallons of water, equivalent to a level of 13.25 feet in a single condensate storage tank or 7.6 feet in each condensate storage tank, and

LA.2

SR 3.5.2.2.b

4. The HPCS system is OPERABLE per Specification 3.5.2 with an OPERABLE flow path capable of taking suction from the condensate storage tank and transferring the water through the spray sparger to the reactor vessel.

LA.1

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APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, 4, and 5*.

ACTION:

A.5 Moved to LCO 3.6.2.2

a. In OPERATIONAL CONDITION 1, 2, or 3 with the suppression chamber water level less than the above limit, restore the water level to within the limit within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 4 or 5* with the suppression chamber water level less than the above limit or drained and the above required conditions not satisfied, suspend CORE ALTERATIONS and all operations that have a potential for draining the reactor vessel and lock the reactor mode switch in the Shutdown position. Establish SECONDARY CONTAINMENT INTEGRITY within 8 hours.

L.1

L.4 (ACTION A)

L.3

ACTIONS C and D

A.1

A.1

A.2

*The suppression chamber is not required to be OPERABLE provided that the reactor vessel head is removed, the cavity is flooded or being flooded from the suppression pool, the spent fuel pool gates are removed when the cavity is flooded, and the water level is maintained within the limits of Specifications 3.9.8 and 3.9.9.

A.3

M.1

APPLICABILITY

L.4

Add proposed Required Action A.1

EMERGENCY CORE COOLING SYSTEMS

SURVEILLANCE REQUIREMENTS

4.5.3.1 The suppression chamber shall be determined OPERABLE by verifying the water level to be greater than or equal to 30 ft 9 3/4 in. at least once per 24 hours. (A.5) Moved to LCO 3.6.2.2

4.5.3.2 With the suppression chamber level less than the above limit or drained in OPERATIONAL CONDITION 4 or 5*, at least once per 12 hours: (A.6) (B)

SR 3.5.2.1 a. Verify the required conditions of Specification 3.5.3.b to be satisfied, or

SR 3.5.2.2 APPLICABILITY b. Verify footnote conditions * to be satisfied.

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*The suppression chamber is not required to be OPERABLE provided that the reactor vessel head is removed, the cavity is flooded or being flooded from the suppression pool, the spent fuel pool gates are removed when the cavity is flooded, and the water level is maintained within the limits of Specifications 3.9.8 and 3.9.9. (A.3) APPLICABILITY (M.1)

Specification 3.5.2

INSTRUMENTATION

See Discussion of Changes for ITS: 3.3.5.1, ECCS Instrumentation, in Section 3.3

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3 The emergency core cooling system (ECCS) actuation instrumentation channels shown in Table 3.3.3-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.3-2.

APPLICABILITY: As shown in Table 3.3.3-1.

ACTION:

a. With an ECCS actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.3-2, declare the channel inoperable until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. With one or more ECCS actuation instrumentation channels inoperable, within 24 hours take the ACTION required by Table 3.3.3-1.

c. With either ADS trip system "A" or "B" inoperable, restore the inoperable trip system to OPERABLE status:

   1. Within 7 days, provided that the HPCS and RCIC systems are OPERABLE; otherwise,

   2. Within 72 hours.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to less than or equal to 128 psig within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.3.3.1 Each ECCS actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.3.1-1.

4.3.3.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed at least once per 18 months.

SR 3.5.2.7

4.3.3.3 The ECCS RESPONSE TIME of each ECCS trip function shall be demonstrated to be within the limit at least once per 18 months. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific ECCS trip system.

A.7 24 LD.1 A.7 LA LB LB

add proposed Note to SR 3.5.2.7 A.7

ADMINISTRATIVE (continued)

A.5 This requirement is being moved to Specification 3.6.2.2 in accordance with the format of the BWR Standard Technical Specifications, NUREG-1434. Any technical changes to this requirement will be addressed in the Discussion of Changes for ITS: 3.6.2.2.

A.6 This Surveillance Requirement is now part of the Applicability. As such, it periodically verifies that the LCO is still within that Applicability. Periodic verification that the unit condition remains within the Applicability is not used in the BWR Standard Technical Specifications, NUREG-1434 (and not typically found in current Technical Specifications). These types of Surveillances are placed under plant specific control to assure control over Applicability changes are performed correctly and in compliance with LCO 3.0.4 and SR 3.0.4 rules. Therefore, this change is considered administrative.

A.7 A Note has been added to proposed SR 3.5.2.7 (current Specification 4.3.3.3) that exempts the ECCS instrumentation from response time testing and allows the design instrumentation response time to be used in the determination of the ECCS RESPONSE TIME. Deletion of the response time test for these instruments was evaluated in NEDO-32291, "System Analyses for Elimination of Selected Response Time Testing Requirements," January 1994, and was determined acceptable since other Technical Specification Surveillances (CHANNEL CALIBRATION, CHANNEL FUNCTIONAL TEST, CHANNEL CHECK, and LOGIC SYSTEM FUNCTIONAL TEST) ensure that instrumentation response times are within acceptable limits. These other tests are normally sufficient to identify failure modes or degradation in instrument response time and assure operation of the analyzed instrument loops within acceptable limits. Furthermore, there are no known failure modes that can be detected by response time testing that cannot also be detected by other Technical Specification Surveillances. In addition, the NRC Safety Evaluation Report (SER) from B.A. Boger (NRC) to R.A. Pinelli (BWROG), dated December 28, 1994, required that the utility commit to certain additional requirements and state this in the plant specific license amendment. WNP-2 has committed to these additional requirements. This evaluation will be documented in a 50.59 evaluation that deletes these instruments from the current WNP-2 ECCS RESPONSE TIME requirements. The evaluation

ADMINISTRATIVE

A.7 (cont'd) will be performed in accordance with the 50.59 process since the actual response times have been removed from WNP-2 TS and placed under WPPSS control as documented in the NRC SER documented in Technical Specification Amendment 139. This evaluation will be complete prior to issuance of an NRC SER for the WNP-2 ITS submittal. Therefore, this change is considered administrative. 1(B)

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 The allowance to not require the suppression pool during cavity flooding has been deleted. The ITS will require the suppression pool to be within the required limits until the cavity is completely flooded (as well as all other listed requirements met). This is an additional restriction on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The details relating to system OPERABILITY (in this case what constitutes an OPERABLE ECCS subsystem) are proposed to be relocated to the Bases. The details for system OPERABILITY are not necessary in the LCO. The definition of OPERABILITY suffices. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LA.2 The condensate storage tank volume which corresponds to the level limit(s) is proposed to be relocated to the Bases. The level limit(s) are retained since this is the information available to the operator regarding the contents of the condensate storage tank(s). These volume and level limits are equivalent and interchangeable. Therefore, moving one of them to the Bases does not change the requirement and is only a change in the presentation. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

TECHNICAL CHANGES - LESS RESTRICTIVE

L.2 (cont'd) vortex prevention for all the ECCS pumps, and provides an additional 135,000 gallons of water (above that needed for NPSH and vortex prevention considerations) for a recirculation/makeup volume. The 135,000 gallons is consistent with the current condensate storage tank requirements when the suppression pool is drained. These three considerations (NPSH, vortexing, and recirculation/makeup volume) are described in the ITS Bases as the reason for the level requirement. In addition, the redundant volume requirement (in cubic feet) has been deleted, leaving only the equivalent volume in feet (i.e., suppression pool water level). The redundant volume requirement is used for the blowdown portion of the MODE 1 LOCA analysis. In MODES 4 and 5, this is not a concern; only the necessary water level needed for NPSH considerations, vortexing prevention, and recirculation/makeup volume (in gallons) is required.

L.3 The requirement to "lock" the reactor mode switch in Shutdown or Refuel is proposed to be deleted. The position of the reactor mode switch is adequately controlled by the MODES definition Table (proposed Table 1.1-1). Reactor mode switch positions other than Refuel and Shutdown result in the unit entering some other MODE; with the associated Technical Specification compliance requirements of that MODE and of proposed LCO 3.0.4. Only the Shutdown or Refuel position of the reactor mode switch are allowed for proposed LCO 3.5.2 since a reactor mode switch position of other than Shutdown or Refuel results in entry into a MODE other than MODE 4 or 5. Therefore, the requirement to "lock" the reactor mode switch in Shutdown or Refuel is proposed to be deleted from Technical Specifications.

L.4 Since the HPCS does not depend on the suppression pool volume for a water source, the ACTION is revised to reflect that only one ECCS subsystem is inoperable. With only one inoperable, current LCO 3.5.2 ACTION a allows 4 hours prior to requiring OPDRVs to be suspended. Therefore, proposed Required Action A.1 has also been added to provide 4 hours to restore the inoperable ECCS subsystem to OPERABLE status consistent with the currently approved Specifications. In addition, when the suppression pool is drained and credit is being maintained for the CST and HPCS as an OPERABLE ECCS subsystem, only that single subsystem could be OPERABLE (no other ECCS subsystem has an alternate source of water). Therefore, operation necessarily must be in accordance with ITS ACTIONS A and B, where the Required Action of Condition B precludes OPDRV (note that Condition B applies 4 hours after Condition A is entered). By virtue of the plant design, and the ACTIONS provided for less than two OPERABLE ECCS subsystems, CTS 3.5.3.b.1 requirement that prohibits OPDRVs is retained. However, as stated above, a 4 hour Completion Time is provided to restore one ECCS subsystem prior to suspending OPDRVs, consistent with current LCO 3.5.2 ACTION a. (B)

DISCUSSION OF CHANGES
ITS: 3.5.3 - RCIC SYSTEM

ADMINISTRATIVE

A.1 Adequate pressure to perform the test also implies adequate flow must be available to perform the tests. Therefore, this change is considered administrative.

A.2 This Note is being deleted because it no longer applies. The Note established the requirement for the RCIC OPERABILITY to include the ability of automatically taking RCIC suction from the suppression pool to begin no later than the Spring 1993 Refueling Outage. Since this has already occurred, the Note has no meaning and deleting it is merely an administrative change.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

None

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The details relating to system OPERABILITY (in this case that the RCIC System shall have a flow path capable of taking suction from the suppression pool and transferring water to the reactor pressure vessel) are proposed to be relocated to the Bases. The details for system OPERABILITY are not necessary in the LCO. The definition of OPERABILITY suffices. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications. (B)

LA.2 The details relating to methods for performing Surveillances are proposed to be relocated to the Bases. These details are not necessary to ensure the OPERABILITY of the RCIC System. The requirements of Specification 3.5.3, RCIC System, and the associated Surveillance Requirements are adequate to ensure the RCIC System is maintained OPERABLE. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications. (B)

LD.1 The Frequencies for performing current Surveillances 4.7.3.c.1, 4.7.3.c.2, and 4.7.3.c.3 (proposed SRs 3.5.3.4 and 3.5.3.5) have been extended from 18 months to 24 months to facilitate a change to the WNP-2 maintenance cycle from 12 months to 24 months. The current conditions in the northwest require that WNP-2 shut down each spring for an annual maintenance and refueling outage. Currently, most of the current Surveillances that are required to be performed on an 18 month interval are performed annually

Specification 3.6.1.1

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3/4.6 CONTAINMENT SYSTEMS

3/4.6.1 PRIMARY CONTAINMENT

PRIMARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

LCO 3.6.1.1 3.6.1.1 PRIMARY CONTAINMENT ~~INTEGRITY~~ shall be ~~maintained~~ OPERABLE (A.1)

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2* and 3. (A.2)

ACTION:

ACTION A / ACTION B: Without PRIMARY CONTAINMENT ~~INTEGRITY~~, restore PRIMARY CONTAINMENT ~~INTEGRITY~~ within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. (A.1)

SURVEILLANCE REQUIREMENTS

4.6.1.1 PRIMARY CONTAINMENT INTEGRITY shall be demonstrated: (A.3)

a. After each closing of each penetration subject to Type B testing, except the primary containment air locks, if opened following Type A or B test, by leak rate testing the seals with gas at P_a, and verifying that when the measured leakage rate for these seals is added to the leakage rates determined pursuant to Surveillance Requirement 4.6.1.2.d for all other Type B and C penetrations, the combined leakage rate is less than or equal to 0.60 L_a. (A.3) moved to Specification 3.5.12 (B)

SR 3.6.1.1.1

b. At least once per 31 days by verifying that all primary containment penetrations** not capable of being closed by OPERABLE containment automatic isolation valves and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic valves secured in position, except as provided in Table 3.6.3-1 of Specification 3.6.3. (A.4) moved to LCO 3.6.1.3

c. By verifying each primary containment air lock is in compliance with the requirements of Specification 3.6.1.3. (A.5)

d. By verifying the suppression chamber is in compliance with the requirements of Specification 3.6.2.1. (A.5)

* See Special Test Exception 3.10.1. (A.2)

**Except valves, blind flanges, and deactivated automatic valves which are within the primary containment or other areas administratively controlled to prohibit access for reasons for personnel safety (i.e., radiation and temperature) and are locked, sealed, or otherwise secured in the closed position (1-1/2 inch and smaller valves connected to vents, drains or test connections must be closed but need not be sealed). Valves inside containment shall be verified closed following primary containment de-inerting, but verification is not required more often than once per 92 days. Valves in other administratively controlled areas shall be verified closed during each COLD SHUTDOWN, but verification is not required more often than once per 31 days. (A.4) moved to LCO 3.6.1.3

Specification 3.6.1.1

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CONTAINMENT SYSTEMS

PRIMARY CONTAINMENT LEAKAGE

LIMITING CONDITION FOR OPERATION

moved to Specification 5.5.12 (B)

3.6.1.2 Primary containment leakage rates shall be limited to: (A.3) (A.6)

SR 3.6.1.1.1 a. An overall integrated leakage rate of less than or equal to L_a, 0.50 percent by weight of the containment air per 24 hours at P_a. (A.3)

b. A combined leakage rate of less than or equal to 0.60 L_a for all penetrations and all valves listed in Table 3.6.3-1, except for main steam line isolation valves* (and valves which are hydrostatically leak tested per Table 3.6.3-1), subject to Type B and C tests when pressurized to P_a. (LA.1)

c. *Less than or equal to 11.5 scf per hour for any one main steam line isolation valve when tested at P_t, 25.0 psig. (A.4) Moved to LCO 3.6.1.3

d. A combined leakage rate of less than or equal to 1 gpm times the total number of ECCS and RCIC containment isolation valves in hydrostatically tested lines which penetrate the primary containment, when tested at 1.10 P_a.

APPLICABILITY: When PRIMARY CONTAINMENT INTEGRITY is required per Specification 3.6.1.1.

ACTION:

With:

Condition A

a. The measured overall integrated primary containment leakage rate exceeding 0.75 L_a, or (A.3) moved to Specification 5.5.12 (LA.1) (B)

b. The measured combined leakage rate for all penetrations and all valves listed in Table 3.6.3-1, except for main steam line isolation valves* (and valves which are hydrostatically leak tested per Table 3.6.3-1), subject to Type B and C tests exceeding 0.60 L_a, or (A.3) moved to Specification 5.5.12 (B)

c. The measured leakage rate exceeding 11.5 scf per hour for any one main steam line isolation valve, or (A.4)

d. The measured combined leakage rate for all ECCS and RCIC containment isolation valves in hydrostatically tested lines which penetrate the primary containment exceeding 1 gpm times the total number of such valves, moved to LCO 3.6.1.3

restore:

Required Action A.1

a. The overall integrated leakage rate(s) to less than or equal to 0.75 L_a, and (A.3) moved to Specification 5.5.12

b. The combined leakage rate for all penetrations and all valves listed in Table 3.6.3-1, except for main steamline isolation valves* and valves which are hydrostatically leak tested per Table 3.6.3-1 subject to Type B and C tests to less than or equal to 0.60 L_a, and (LA.1)

*Exemption to Appendix J of 10 CFR Part 50. (A.3) Moved to Specification 5.5.12 (B)

CONTAINMENT SYSTEMS

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued) (A.4) moved to LCO 3.6.1.3

c. The leakage rate to less than or equal to 11.5 scf per hour for any one main steam line isolation valve, and

d. The combined leakage rate for all ECCS and RCIC containment isolation valves in hydrostatically tested lines which penetrate the primary containment to less than or equal to 1 gpm times the total number of such valves,

prior to increasing reactor coolant system temperature above 200°F. (M.1)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1

4.6.1.2 Perform required primary containment leakage rate testing in accordance with the Primary Containment Leakage Rate Testing Program described in Specification 6.8.4.f.

a. Deleted

b. Deleted

c. Deleted

d. Deleted (B)

e. Deleted

f. Deleted

g. Deleted

h. Deleted

i. Deleted

j. Deleted

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Specification 3.6.1.1

CONTAINMENT SYSTEMS

PRIMARY CONTAINMENT STRUCTURAL INTEGRITY

LIMITING CONDITION FOR OPERATION

LCO 3.6.1.1

3.6.1.5 The structural integrity of the primary containment shall be maintained at a level consistent with the acceptance criteria in Specification 4.6.1.5. (A.7)

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

Action A: With the structural integrity of the primary containment not conforming to the above requirements, restore the structural integrity to within the limits within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. (1) (M.2)

Action B

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1

4.6.1.5.1 The structural integrity of the exposed accessible interior and exterior surfaces of the primary containment shall be determined during the shutdown for each Type A containment leakage rate test by a visual inspection of those surfaces. This inspection shall be performed prior to the Type A containment leakage rate test to verify no apparent changes in appearance or other abnormal degradation. (A.7)

4.6.1.5.2 Reports Any abnormal degradation of the primary containment structure detected during the above required inspections shall be reported to the Commission pursuant to Specification 6.9.1. This report shall include a description of the condition of the primary steel containment, the inspection procedure and the corrective actions taken.

Specification 3.6.1.1

CONTAINMENT SYSTEMS

3/4.6.2 DEPRESSURIZATION SYSTEMS

SUPPRESSION CHAMBER

LIMITING CONDITION FOR OPERATION

3.6.2.1 The suppression chamber shall be OPERABLE with:

a. The pool water:

1. Volume between 127,197 ft^3 and 128,827 ft^3, equivalent to a level between 30 ft 9 3/4 in. and 31 ft 1 3/4 in., and a
2. Maximum average temperature of 90°F during OPERATIONAL CONDITION 1 or 2, except that the maximum average temperature may be permitted to increase to:
   a) 105°F during testing which adds heat to the suppression chamber.
   b) 110°F with THERMAL POWER less than or equal to 1% of RATED THERMAL POWER.
   c) 120°F with the main steam line isolation valves closed following a scram.

LCO 3.6.1.1 b. Drywell-to-suppression chamber bypass leakage less than or equal to 10% of the acceptable $A/\sqrt{k}$ design valve of 0.05 ft^2. A.8

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With the suppression chamber water level outside the above limits, restore the water level to within the limits within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 1 or 2 with the suppression chamber average water temperature greater than [illegible], restore the average temperature to less than or equal to 90°F within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours, except, as permitted above:

1. With the suppression chamber average water temperature greater than 105°F during testing which adds heat to the suppression chamber, stop all testing which adds heat to the suppression chamber and restore the average temperature to less than 90°F within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.
2. With the suppression chamber average water temperature greater than:
   a) 90°F for more than 24 hours and THERMAL POWER greater than 1% of RATED THERMAL POWER, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.
   b) 110°F, place the reactor mode switch in the Shutdown position and operate at least one residual heat removal loop in the suppression pool cooling mode.
3. With the suppression chamber average water temperature greater than 120°F, depressurize the reactor pressure vessel to less than 200 psig within 12 hours.

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See Discussion of Changes for ITS 3.6.2.1, "Suppression Pool Average Temperature," and ITS 3.6.2.2, "Suppression Pool Water Level," in this section.

CONTAINMENT SYSTEMS

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

c. With one suppression chamber water temperature instrumentation channel in any sector inoperable, restore the inoperable channel(s) to OPERABLE status within 7 days or verify suppression chamber water temperature to be within the limits at least once per 12 hours.

d. With more than one suppression pool water temperature instrumentation channel in the same sector inoperable, restore at least one inoperable water temperature instrumentation channel in each sector to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

ACTION A

e. With the drywell-to-suppression chamber bypass leakage in excess of the limit, restore the bypass leakage to within the limit prior to increasing reactor coolant temperature above 200°F. M.1

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SURVEILLANCE REQUIREMENTS

4.6.2.1 The suppression chamber shall be demonstrated OPERABLE:

a. By verifying the suppression chamber water volume to be within the limits at least once per [illegible] hours.

b. At least once per 24 hours in OPERATIONAL CONDITION 1 or 2 by verifying the suppression chamber average water temperature to be less than or equal to 90°F, except:

1. At least once per 5 minutes during testing which adds heat to the suppression chamber, by verifying the suppression chamber average water temperature less than or equal to 105°F.

2. At least once per hour when suppression chamber average water temperature is greater than or equal to 90°F, by verifying:

a) Suppression chamber average water temperature to be less than or equal to 110°F, and

b) THERMAL POWER to be less than or equal to 1% of RATED THERMAL POWER after suppression chamber average water temperature has exceeded 90°F for more than 24 hours.

3. At least once per 30 minutes following a scram with suppression chamber average water temperature greater than or equal to 90°F, by verifying suppression chamber average water temperature less than or equal to 120°F.

See Discussion of Changes for ITS: 3.6.2.1, "Suppression Pool Average Temperature," and ITS 3.6.2.2, Suppression Pool Water Level," in this section.

CONTAINMENT SYSTEMS

SURVEILLANCE REQUIREMENTS (Continued)

See Discussion of Changes for ITS: 3.6.2.1 "Suppression Pool Average Temperature," in this Section.

c. By verifying at least eight suppression pool water temperature instrumentation channels, at least two in each suppression pool sector, OPERABLE by performance of a:

1. CHANNEL CHECK at least once per 24 hours,

2. CHANNEL FUNCTIONAL TEST at least once per 31 days, and

3. CHANNEL CALIBRATION at least once per 18 months,

with the water high temperature alarm setpoints for ≤ 90°F, 105°F, 110°F and 120°F.

SR 3.6.1.1.2

d. By conducting drywell-to-suppression chamber bypass leak tests and verifying that the $A/\sqrt{k}$ calculated from the measured leakage is within the specified limit when drywell-to-suppression chamber bypass leak tests are conducted:

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1. At least once per 18 months at an initial differential pressure of 1.5 psi, and — 24 — LD.1

2. At the first refueling outage and then on the schedule required for Type A Overall Integrated Containment Leakage Rate tests by Specification 4.6.1.2, at an initial differential pressure of 5 psi,

except that, if the first two 5 psi leak tests performed up to that time result in:

1. A calculated $A/\sqrt{k}$ within the specified limit, and

2. The $A/\sqrt{k}$ calculated from the leak tests at 1.5 psi is ≤ 20% of the specified limit, — A.9

then the leak tests at 5 psi may be discontinued.

If any 1.5 psi or 5 psi leak test results in:

1. A calculated $A/\sqrt{k}$ greater than the specified limit, or

2. A calculated $A/\sqrt{k}$ from a 1.5 psi leak test > 20% of the specified limit, — A.10

then the test schedule for subsequent tests shall be reviewed by the Commission.

SR 3.6.1.1.2 2nd Frequency

If two consecutive 1.5 psi leak tests result in a calculated $A/\sqrt{k}$ greater than the specified limit, then:

Specification 3.6.1.1

CONTAINMENT SYSTEMS

SURVEILLANCE REQUIREMENTS (Continued)

SR 3.6.1.1.2.1. A 1.5 psi leak test shall be performed at least once per 9 months until two consecutive 1.5 psi leak tests result in the calculated $A/\sqrt{k}$ within the specified limits, and

2. ~~A 5 psi leak test, performed with the second consecutive successful 1.5 psi leak test, results in a calculated $A/\sqrt{k}$ within the specified limit, after which the above schedule for only 1.5 psi leak tests may be resumed.~~ A.9

~~If two consecutive 5 psi leak tests result in a calculated $A/\sqrt{k}$ greater than the specified limit, then a 5 psi leak test shall be performed at least once per 9 months until two consecutive 5 psi leak tests result in a calculated $A/\sqrt{k}$ within the specified limit, after which the above schedule for only 1.5 psi leak tests may be resumed.~~ A.9

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ADMINISTRATIVE

A.1 The definition of PRIMARY CONTAINMENT INTEGRITY has been deleted from the proposed Technical Specifications. It is replaced with the requirement for primary containment to be OPERABLE. This was done because of the confusion associated with the definition compared to its use in the respective LCO. The change is editorial in that all the requirements are specifically addressed in the proposed LCO for the primary containment along with the remainder of the LCOs in the Primary Containment Section (i.e., air locks, isolation valves, suppression pool, etc.). Therefore the change is a presentation preference adopted by the BWR Standard Technical Specifications, NUREG-1434.

A.2 The format of the proposed Technical Specifications does not include "cross references." The existing reference to "See Special Test Exception 3.10.1" serves no functional purpose, and therefore its removal is administrative.

A.3 Primary containment leakage rate requirements (10 CFR 50 Appendix J, Type A, B and C tests) are proposed to be a supporting surveillance for Primary Containment OPERABILITY (proposed SR 3.6.1.1.1). The essence of an OPERABLE containment is its leak-tightness.

Additionally, the existing Technical Specifications contain details which are found in 10 CFR 50 Appendix J: 1) limit for combined Type B and C leakage (0.6 L_a); 2) limit for measured Type A leakage (0.75 L_a); and 3) the description of the test method or requirements to perform the tests. These regulations require licensee compliance, cannot be revised by the licensee, and are addressed by direct reference in the Technical Specifications. Therefore, the details of the regulations within the Technical Specifications are repetitious and unnecessary. Thus, they are only found a single time, and that is in proposed Specification 5.5.12, Primary Containment Leakage Rate Testing Program. All references to the actual leakage rate limits will not be used in proposed Specification 3.6.1.1, just a reference to the required limits, if needed. Any technical changes to the portions of the requirements being moved to Specification 5.5.12 will be addressed in the Discussion of Changes for ITS: 5.5. (B)

Therefore, retaining the requirement to meet the requirements of 10 CFR 50 Appendix J, Option B, as modified by approved exemptions (as described in the Primary Containment Leakage Rate Testing Program in Section 5.5 of the proposed Technical Specifications), and eliminating the Technical Specification details that are found in Appendix J, is considered a presentation preference, which is administrative. (B)

(B)

ADMINISTRATIVE (continued)

A.4 These requirements, relating to the position of PCIVs, and the allowed leakage rates and testing of MSIVs and valves in hydrostatically tested lines, have been moved to Specification 3.6.1.3 in accordance with the format of the BWR Standard Technical Specifications, NUREG-1434. Any technical changes to these requirements will be addressed in the Discussion of Changes for ITS: 3.6.1.3.

A.5 The requirements for air locks and the suppression pool remain within the Technical Specifications. Providing a cross reference to them only adds confusion when evaluating compliance with Primary Containment OPERABILITY. Therefore removal of these references is administrative. (B)

A.6 The definition for L_a has been moved to proposed Specification 5.5.12, Primary Containment Leakage Rate Testing Program, consistent with the format of the BWR Standard Technical Specifications, NUREG-1434. Any technical changes to the requirements will be addressed in the Discussion of Changes for ITS: 5.5. (B)

A.7 Primary containment structural integrity requirements 10 CFR 50 Appendix J) are proposed to be a supporting Surveillance for Primary Containment OPERABILITY (proposed SR 3.6.1.1.1); the essence of an OPERABLE containment is its leak-tightness. The existing Technical Specifications contain details which are also found in 10 CFR 50 Appendix J: visual inspection prior to each Type A containment leakage rate test. These regulations require licensee compliance, cannot be revised by the licensee, and are addressed by direct reference in the Technical Specifications. The details of the regulations within the Technical Specifications are repetitious and unnecessary.

In addition, the structural integrity reporting requirement is a duplication of information required by 10 CFR 50.73 and 10 CFR 50, Appendix J. The timing of the report is different if the degradation is not serious, but 10 CFR 50, Appendix J requires only that this information be provided with the ILRT Report. If the principal safety barrier, i.e., the primary containment, is seriously degraded, a 30 day report is required by 10 CFR 50.73. Since this special report duplicates these requirements, it is unnecessary and is deleted.

Therefore, retaining the requirement to meet the requirements of 10 CFR 50 Appendix J, as modified by approved exemptions (as described in the Primary Containment Leakage Rate Testing Program in Section 5.5 of the proposed Technical Specifications), and eliminating the Technical Specification details that are found in Appendix J, is considered a presentation preference, which is administrative. (B)

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CONTAINMENT SYSTEMS

PRIMARY CONTAINMENT AIR LOCKS

LIMITING CONDITION FOR OPERATION

LCO 3.6.1.2

3.6.1.3 Each primary containment air lock shall be OPERABLE with:

SR 3.6.1.2.2 a. The interlock operable and engaged such that both doors cannot be opened simultaneously, and

b. Both doors closed except when the air lock is being used for normal transit entry and exit through the containment, and (LA.1)

SR 3.6.1.2.1 c. An overall air lock leakage rate of less than or equal to 0.05 L_a at P_a. (A.2) moved to Specification 5.5.12 (B)

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2* and 3. (A.1)

ACTION: add proposed Actions Note 1 (L.1); add proposed Actions Note 2 (A.2)

ACTION B

a. With the interlock mechanism inoperable: (A.4) add proposed Note 1 to Required Action B

1. Maintain (A.3) at least one operable air lock door closed and either (A.5) return the interlock to service within 24 hours or lock at least one operable air lock door closed.

2. Operation may then continue until the interlock is returned to service provided that one of the air lock doors is verified locked closed prior to each closing of the shield door and at least once per shift while the shield door is open. (L.2)

3. Personnel passage through the air lock is permitted provided an individual is dedicated to assure that one operable air lock door remains locked at all times so that both air lock doors cannot be opened simultaneously.

4. The provisions of Specification 3.0.4 are not applicable. (A.6) (A.4) add proposed Note 1 to Required Action A

ACTION A

b. With one primary containment air lock door inoperable: add proposed Note 2 to Required Action A (L.3)

1. Maintain (A.3) at least the OPERABLE air lock door closed and either restore the inoperable air lock door to OPERABLE status within 24 hours (A.5) or lock the OPERABLE air lock door closed.

2. Operation may then continue until performance of the next required overall air lock leakage test (A.6) provided that the OPERABLE air lock door is verified to be locked closed immediately prior to each closing of the shield door and at least once per shift while the shield door is open. (L.2)

*See Special Test Exception 3.10.1. (A.1)

CONTAINMENT SYSTEMS

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

ACTION D 3. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

A.6 4. The provisions of Specification 3.0.4 are not applicable.

A.2 add proposed Required Action C.1

c. With the primary containment air lock inoperable, except as a result of an inoperable air lock door or an inoperable interlock mechanism, maintain at least one air lock door closed; restore the inoperable air lock to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

ACTION C — A.3

ACTION D

SURVEILLANCE REQUIREMENTS

4.6.1.3 Each primary containment air lock shall be demonstrated OPERABLE:

SR 3.6.1.2.2 a. By verifying interlock operation (i.e., that only one door in each air lock can be opened at a time).

A.2 add proposed SR 3.6.1.2.1 Notes 1 and 2

1. Prior to using the air lock in Operating Conditions 1, 2 and 3 but not required more than once per 6 months, 24 L.4

2. Following maintenance that could affect the interlock mechanism. L.5

SR 3.6.1.2.1

A.2 limits moved to Specification 5.5.12

b. Within 72 hours following each closing, except when the air lock is being used for multiple entries, then at least once per 72 hours, by verifying seal leakage rate less than or equal to 0.025 L_a when the gap between the door seals is pressurized to 10 psig.

c. By conducting an overall air lock leakage test at P_a, and by verifying that the overall air lock leakage rate is within its limit:

SR 3.6.1.2.1

1. At intervals determined in accordance with 10 CFR 50 Appendix J using the methods and provisions outlined in the Primary Containment Leakage Rate Testing Program described in Specification 6.8.4.f, and

A.2 2. Prior to establishing PRIMARY CONTAINMENT INTEGRITY when maintenance had been performed on the air lock that could affect the air lock sealing capability*.

B

*Exception to Appendix J of 10 CFR 50.

DISCUSSION OF CHANGES
ITS: 3.6.1.2 - PRIMARY CONTAINMENT AIR LOCK

ADMINISTRATIVE

A.1 The format of the proposed Technical Specifications does not include cross references. The existing reference to "See Special Test Exception 3.10.1" serves no purpose, and therefore its removal is an administrative difference in presentation.

A.2 The existing Technical Specifications contain the details for air lock leakage surveillances which are also found in 10 CFR 50 Appendix J. These regulations require licensee compliance, cannot be revised by the licensee, and are addressed by direct reference in the Technical Specifications (as described in the Primary Containment Leakage Rate Testing Program in Section 5.5 of the proposed Technical Specifications). Therefore, these details of the regulations within the Technical Specifications are unnecessary. Furthermore, exceptions presented within the regulations themselves, are also details which are adequately presented without repeating the details within the Technical Specifications. The only requirements are that the overall leakage rate ($0.05L_a$), the door leakage rate ($0.025L_a$), and test pressure/time be in Technical Specifications. These have been moved to proposed Specification 5.5.12. Any technical changes to these requirements will be addressed in the Discussion of Changes for ITS: 5.5. A Surveillance will be maintained (proposed SR 3.6.1.2.1), which requires air lock leakage rate testing in accordance with the Primary Containment Leakage Rate Testing Program.

Therefore, retaining the requirement to meet the requirements of 10 CFR 50 Appendix J, as modified by approved exemptions (as described in the Primary Containment Leakage Rate Testing Program in Section 5.5 of the proposed Technical Specifications), and eliminating the Technical Specification details that are also found in Appendix J, is considered a presentation preference, which is administrative.

Four Notes are proposed. These Notes facilitate use and understanding of the intent of:

1) (For ACTIONS Note 2) considering the primary containment inoperable in the event air lock leakage results in the acceptance criteria being not met.

2) (For Required Action C.1) ensuring that the primary containment overall leakage is evaluated, against the acceptance criteria, if an air lock is inoperable.

3) (For SR 3.6.1.2.1, Note 1) the overall air lock acceptance criteria when one air lock door is inoperable. Since the inoperability is known to be only affecting one door, the barrel and the other OPERABLE door are providing a sufficient containment barrier. Even though the overall test could not be satisfied (SR 3.0.1 would normally require this to result in declaring the LCO not met - possibly

ADMINISTRATIVE

A.2 (cont'd) requiring proposed Condition C (current ACTION C) to be entered), the Note clarifies the intent that the previous test not be considered "not met."

4) (For SR 3.6.1.2.1, Note 2) ensuring that the primary containment overall leakage is evaluated, against the acceptance criteria, every time the SR is performed. (B)

These clarifications are consistent with the intent and interpretation of the existing Technical Specifications, and are therefore considered administrative presentation preferences.

A.3 The word "maintain" has been changed to "verify", and a 1 hour time consistent with the Primary Containment LCO, has been provided to perform the verification since it is expected that the door will be closed. This change is considered administrative.

A.4 These proposed Notes (Required Actions A and B, Note 1: "Required Actions...are not applicable if...Condition C is entered") and proposed Condition C provide more explicit instructions for proper application of the ACTIONS for Technical Specification compliance. In conjunction with the proposed Specifications 1.3, "Completion Times," these ACTIONS provide direction consistent with the intent of the existing ACTIONS for one inoperable air lock door in the air lock. In the Required Actions A and B Notes, there is a recognition that if both doors in the air lock are inoperable (Condition C entered), then an "OPERABLE" door does not exist to be closed (Required Actions A.1, A.2, A.3, B.1, B.2, and B.3 cannot be met).

A.5 The revised presentation of ACTIONS (based on the BWR Standard Technical Specifications, NUREG-1434) does not explicitly detail options to "restore...to OPERABLE status" or "return...to service." These actions are always an option, and are implied in all ACTIONS. Omitting these actions is editorial.

A.6 The requirement for performing the overall air lock leakage test is a requirement of 10 CFR 50 Appendix J (as described in the Primary Containment Leakage Rate Testing Program in Section 5.5 of the proposed Technical Specifications). This requirement is embodied in proposed SR 3.6.1.2.1. It is possible that the test would not be able to be performed with an inoperable air lock door, and a plant shutdown would be required due to the inability to perform the required surveillance. However, this restriction on continued operation need not be specified (as is the case in existing ACTION b.2) - it exists inherently as a result of the required Appendix J testing. Once the ACTIONS are revised to eliminate the reference to this surveillance restriction (as proposed in the conversion to the BWR Standard Technical Specifications, NUREG-1434), the exception to LCO 3.0.4 applicability (current ACTION b.4) is not necessary, since the proposed LCO 3.0.4 allows MODE changes provided continued (B)

ADMINISTRATIVE

A.6 (cont'd) operations is allowed in the ACTIONS. In addition, current ACTION a.4 is also deleted since the allowance is now provided in proposed LCO 3.0.4. Therefore, no change in operation requirements or intent is made, and the proposed revision to eliminate a specific restriction on continued operation, and the corresponding exception to LCO 3.0.4, is considered an administrative presentation preference.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

None

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The details comprising OPERABILITY of the air lock are proposed to be relocated to the Bases. Air lock interlock OPERABILITY requirements are explicitly required in Surveillance Requirements (proposed SR 3.6.1.2.2) for air lock OPERABILITY. The OPERABILITY of this interlock ensures one air lock door shall be closed "when the air lock is being used for normal transit entry and exit through the containment." The requirement for both doors to normally remain closed is included in the Bases. Should only one door remain closed, the safety design of the containment and its air locks still provide a sufficiently leak tight barrier for postulated events. As a result, these details are not necessary to be included in the Technical Specifications to ensure OPERABILITY of the air lock is maintained. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

"Specific"

L.1 Proposed LCO 3.6.1.2, ACTIONS Note 1, is added to the Technical Specifications to allow entry through a closed or locked air lock door for the purpose of making repairs. If the outer door is inoperable, then it may be easily accessed for repair. If the inner door is the one that is inoperable, however, then it is proposed to allow entry through the OPERABLE outer door, which means there is a short time during which the primary containment boundary is not intact (during access through the outer door).

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) The proposed allowance will have strict administrative controls, which are detailed in the Bases. A dedicated (i.e., not involved with any repair or other maintenance effort) individual will be assigned to ensure: 1) the door is opened only for the period of time required to gain entry into or exit from the air lock, and 2) any OPERABLE door is re-locked prior to the departure of the dedicated individual.

Repairs are directed towards reestablishing two OPERABLE doors in the air lock. Two OPERABLE doors closed is clearly the most desirable plant condition for air locks. The existing ACTIONS, in some circumstances, allow indefinite operation with only one OPERABLE door locked closed. Two OPERABLE doors closed is clearly an improvement on safety over one OPERABLE door locked closed. By not allowing access to make repairs, the existing ACTIONS could result in an inability of the plant to establish and maintain this highest level of safety possible (two OPERABLE doors closed), without a forced plant shutdown. Furthermore, the overall air lock test must be performed every 6 months. This could eventually result in a plant shutdown from the inability to properly perform this test due to the inability to affect repairs to the inoperable door.

Therefore, allowing entry and exit, while temporarily allowing loss of containment integrity, is proposed based on the expected result of restoring two OPERABLE doors to the air lock. Restricting this access to make repairs of an inoperable door or air lock ensures this allowance applies only towards meeting this goal. This change is acceptable due to the low probability of an event that could pressurize the primary containment during the short time in which the containment integrity is compromised, and the increased safety attained by completing repairs such that two OPERABLE doors can be closed.

L.2 The actions relating to verification that a door is locked closed has been revised. Currently, an air lock door that is locked closed to comply with actions is required to be verified locked closed prior to each closing of the shield door and every 12 hours if the shield door is open. The shield door only allows access to the outer air lock door, and is not part of the primary containment. The proposed Required Actions only require verification of a locked closed door every 31 days, consistent with other current actions as they relate to verification of primary containment penetrations (e.g., PCIVs). The position of the shield door has no direct impact on the position of the air lock door; its closure just precludes access to the air lock door. However, with the shield door open, access to the air lock door locking device is still administratively controlled, thereby ensuring the door cannot be inadvertently opened.

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CONTAINMENT SYSTEMS

3/4.6.3 PRIMARY CONTAINMENT ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

LCO 3.6.1.3 3.6.3 ~~The~~ For primary containment isolation valves and the reactor instrumentation line excess flow check valves shown in Table 3.6.3-1 shall be OPERABLE with isolation times less than or equal to those shown in Table 3.6.3-1.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3, add proposed second Applicability

ACTION: add proposed Note 2 to ACTIONS, add proposed Notes 3 and 4 to ACTIONS

a. With one or more of the primary containment isolation valves shown in Table 3.6.3-1 inoperable, maintain at least one isolation valve OPERABLE in each affected penetration that is open and within 4 hours either: (ACTIONS A and C; 8 hours for MSIVs)

1. Restore the inoperable valve(s) to OPERABLE status, or

2. Isolate each affected penetration by use of at least one deactivated automatic valve secured in the isolated position,* or

3. Isolate each affected penetration by use of at least one closed manual valve or blind flange*, and or check valve with flow secured

4. The provisions of Specification 3.0.4 are not applicable provided that the affected penetration is isolated in accordance with ACTION a.2. or a.3. above, and provided that the associated system, if applicable, is declared inoperable and the appropriate ACTION statements for that system are performed.

Required Action A.1 — NOTE 3 to ACTIONS

ACTION E Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

add proposed ACTION B

b. With one or more of the reactor instrumentation line excess flow check valves shown in Table 3.6.3-1 inoperable, operation may continue and the provisions of Specifications 3.0.3 and 3.0.4 are not applicable provided that within 4 hours (12) either: (ACTION C)

1. The inoperable valve is returned to OPERABLE status, or

2. The instrument line is isolated and the associated instrument is declared inoperable. — NOTE 3 To ACTIONS

ACTION E Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

add proposed ACTION F

Note 1 to ACTIONS: *Isolation valves closed to satisfy these requirements may be reopened on an intermittent basis under administrative control.

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CONTAINMENT SYSTEMS

SURVEILLANCE REQUIREMENTS

4.6.3.1 Each primary containment isolation valve ~~shown in Table 3.6.3-1~~ shall be demonstrated OPERABLE prior to returning the valve to service after maintenance, repair, or replacement work is performed on the valve or its associated actuator, control or power circuit by cycling the valve through at least one complete cycle of full travel and verifying the specified isolation time.

SR 3.6.1.3.7 4.6.3.2 Each primary containment automatic isolation valve ~~shown in Table 3.6.3-1~~ shall be demonstrated OPERABLE ~~during COLD SHUTDOWN or REFUELING~~ at least once per 18 months by verifying that on a containment isolation test signal each automatic isolation valve actuates to its isolation position.

SR 3.6.1.3.5 4.6.3.3 The isolation time of each primary containment power-operated or automatic valve ~~shown in Table 3.6.3-1~~ shall be determined to be within its limit when tested pursuant to Specification 4.0.5.

SR 3.6.1.3.8 4.6.3.4 Each reactor instrumentation line excess flow check valve ~~shown in Table 3.6.3-1~~ shall be demonstrated OPERABLE at least once per 18 months by verifying that the valve checks flow at greater than a 10 psid differential pressure in hydraulic service and 15 psid differential pressure in pneumatic service.

4.6.3.5 Each traversing in-core probe system explosive isolation valve shall be demonstrated OPERABLE:

SR 3.6.1.3.4 a. At least once per 31 days by verifying the continuity of the explosive charge.

SR 3.6.1.3.9 b. At least once per 18 months by removing the explosive squib from at least one explosive valve, such that each explosive squib in each explosive valve will be tested at least once per 90 months, and initiating the explosive squib. The replacement charge for the exploded squib shall be from the same manufactured batch as the one fired or from another batch which has been certified by having at least one of that batch successfully fired. No explosive squib shall remain in use beyond the expiration of its shelf-life and operating life, as applicable.

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Specification 3.6.1.3

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TABLE 3.6.3-1

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	VALVE GROUP(a)	MAXIMUM ISOLATION TIME (Seconds)
a. Automatic Isolation Valves		
Main Steam Isolation Valves	1	5*
MS-V-22A,B,C,D(b)		
MS-V-28A,B,C,D(b)		
Main Steam Line Drains	1	
MS-V-16		25
MS-V-19		25
MS-V-67A,B,C,D(b)		15
Reactor Recirc. Cooling Sample Valves	2	5
RRC-V-19		
RRC-V-20		
Containment Purge Exhaust & Supply#	3	
CEP-V-1A,2A,3A,4A		4
CEP-V-1B,2B,3B,4B		4
CSP-V-1		4
CSP-V-2		4
CSP-V-3		4
CSP-V-4		4
CSP-V-93		4
CSP-V-96		4
CSP-V-97		4
CSP-V-98		4

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TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	VALVE GROUP(a)	MAXIMUM ISOLATION TIME (Seconds)
a. Automatic Isolation Valves (Continued)		
Equipment Drain (Radioactive)	4	15
EDR-V-19 EDR-V-20		
Floor Drain (Radioactive)	4	15
FDR-V-3 FDR-V-4		
Fuel Pool Cooling/Suppression Pool Cleanup	4	35
FPC-V-149 FPC-V-153(f) FPC-V-154(f) FPC-V-156		
Reactor Recirculation Hydraulic Control(e)(l)	4	15
HY-V-17A,B HY-V-18A,B HY-V-19A,B HY-V-20A,B HY-V-33A,B HY-V-34A,B HY-V-35A,B HY-V-36A,B		
Traversing Incore Probe	4	5
TIP-V-1,2,3,4,5 TIP-V-15		

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TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	VALVE GROUP(a)	MAXIMUM ISOLATION TIME (Seconds)
a. Automatic Isolation Valves (Continued)		
Reactor Closed Cooling	4	60
RCC-V-6		
RCC-V-21		
RCC-V-40		
RCC-V-104		
Radiation Monitoring Supply & Return	4	5
PI-VX-250		
PI-VX-251		
PI-VX-253		
PI-VX-256		
PI-VX-257		
PI-VX-259		
Residual Heat Removal		
RHR-V-123A,B(g)	5	15
RHR-V-8(g)(k)	6	40
RHR-V-9(g)	6	40
RHR-V-23(g)	6	90
RHR-V-53A,B(g)	6	40
RHR-V-24A,B(c)	10	270
RHR-V-21	10	270
RHR-V-27A,B(c)	10	36
Reactor Water Cleanup System	1	
RWCU-V-1(d)		30(j)
RWCU-V-4		21(j)

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TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	VALVE GROUP(a)	MAXIMUM ISOLATION TIME (Seconds)
a. Automatic Isolation Valves (Continued)		
Reactor Core Isolation Cooling		
RCIC-V-8	8	26
RCIC-V-63	8	16
RCIC-V-76	8	22
Low Pressure Core Spray		
LPCS-V-12	10	180
High Pressure Core Spray		
HPCS-V-23	11	180
b. Excess Flow Check Valves(e)		
Containment Atmosphere		N.A.
PI-EFC-X29b		
PI-EFC-X29f		
PI-EFC-X30a		
PI-EFC-X30f		
PI-EFC-X42c		
PI-EFC-X42f		
PI-EFC-X61c		
PI-EFC-X62b		
PI-EFC-X69f		
PI-EFC-X78a		

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TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	VALVE GROUP(a)	MAXIMUM ISOLATION TIME (Seconds)
b. Excess Flow Check Valves (e) (Continued)		
Containment Atmosphere (Continued)		N.A.
PI-EFC-X66		
PI-EFC-X67		
PI-EFC-X82b		
PI-EFC-X84a		
PI-EFC-X86A,B		
PI-EFC-X87A,B		
PI-EFC-X119		
Reactor Pressure Vessel		N.A.
PI-EFC-X18A,B,C,D		
PI-EFC-X37e,f		
PI-EFC-X38a,b,c,d,e,f		
PI-EFC-X39a,b,d,e		
PI-EFC-X40c,d		
PI-EFC-X41c,d		
PI-EFC-X42a,b		
PI-EFC-X44Aa,Ab,Ac,Ad,Ae,Af,Ag,Ah,Aj, Ak,Al,Am		
PI-EFC-X44Ba,Bb,Bc,Bd,Be,Bf,Bg,Bh,Bj, Bk,Bl,Bm		
PI-EFC-X61a,b		
PI-EFC-X62c,d		
PI-EFC-X69a,b,e		
PI-EFC-X70a,b,c,d,e,f		
PI-EFC-X71a,b,c,d,e,f		
PI-EFC-X72a		
PI-EFC-X73a		
PI-EFC-X74a,b,e,f		

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TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	VALVE GROUP(a)	MAXIMUM ISOLATION TIME (Seconds)
b. Excess Flow Check Valves (e) (Continued)		
Reactor Pressure Vessel (Continued)		N.A.
PI-EFC-X75a,b,c,d,e,f PI-EFC-X78b,c,f PI-EFC-X79a,b PI-EFC-X106 PI-EFC-X107 PI-EFC-X108 PI-EFC-X109 PI-EFC-X110 PI-EFC-X111 PI-EFC-X112 PI-EFC-X113 PI-EFC-X114 PI-EFC-X115		
Other		N.A.
PI-EFC-X40e,f PI-EFC-X41e,f		
c. Manual Containment Isolation Valves		
Demineralized Water		N.A.
DW-V-156 DW-V-157		
Containment Air System		N.A.
CAS-VX-82e CAS-V-730		

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TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	VALVE GROUP(a)	MAXIMUM ISOLATION TIME (Seconds)
c. Manual Containment Isolation Valves (Continued)		
Service Air		N.A.
SA-V-109		
Residual Heat Removal		N.A.
RHR-V-11A,B RHR-V-120 RHR-V-121 RHR-V-124A,B RHR-V-125A,B		
Reactor Core Isolation Cooling		N.A.
RCIC-V-64 RCIC-V-742(g)(b)		
Air Supply to Testable Check Valves		N.A.

Air Supply	Check Valve
PI-VX-42d PI-VX-216	RHR-V-50A
PI-VX-69c PI-VX-221	RHR-V-50B
PI-VX-61f PI-VX-219	RHR-V-41A
PI-VX-54Bf PI-VX-218	RHR-V-41B

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TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	VALVE GROUP(a)	MAXIMUM ISOLATION TIME (Seconds)
c. Manual Containment Isolation Valves (Continued)		
Air Supply to Testable Check Valves (Continued)		N.A.
PI-VX-62f	RHR-V-41C	
PI-VX-220		
LPCS-V-66	LPCS-V-6	
LPCS-V-67		
HPCS-V-65	HPCS-V-5	
HPCS-V-68		
RCIC-V-184	RCIC-V-66	
RCIC-V-740		
d. Other Containment Isolation Valves		
Main Steam Leakage Control(b)		N.A.
MSLC-V-3A,B,C,D		
Reactor Feedwater/RWCU Return		N.A.
RFW-V-10A,B		
RFW-V-32A,B		
RFW-V-65A,B		
RWCU-V-40		
High Pressure Core Spray		N.A.
HPCS-V-4(g)(b)		
HPCS-V-5(g)(b)		
HPCS-V-12		
HPCS-V-15(f)(b)		

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TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	VALVE GROUP(a)	MAXIMUM ISOLATION TIME (Seconds)
d. Other Containment Isolation Valves (Continued)		
High Pressure Core Spray (Continued)		N.A.
HPCS-RV-14(e)(h) HPCS-RV-35(e)(h)		
Low Pressure Core Spray		N.A.
LPCS-V-1(f)(b) LPCS-V-5(g)(b) LPCS-V-6(g)(b) LPCS-RV-18(e)(h) LPCS-RV-31(e)(h) LPCS-FCV-11		
Standby Liquid Control		N.A.
SLC-V-7 SLC-V-4A,B		
Reactor Core Isolation Cooling		N.A.
RCIC-V-13(g)(b) RCIC-V-19 RCIC-V-28 RCIC-V-31(f)(b) RCIC-V-40 RCIC-V-66(g)(b) RCIC-V-68 RCIC-V-69		

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TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	VALVE GROUP(a)	MAXIMUM ISOLATION TIME (Seconds)
d. Other Containment Isolation Valves (Continued)		
Residual Heat Removal/Low Pressure Injection		N.A.
RHR-V-4A,B,C(f)(b)		
RHR-V-16A,B		
RHR-V-17A,B		
RHR-V-41A,B(g)(b)		
RHR-V-42A,B,C(g)(b)		
RHR-V-50A,B(g)(b)		
RHR-V-73A,B		
RHR-V-134A,B(c)		
RHR-V-209(g)(b)		
RHR-RV-1A,B(e)(h)		
RHR-RV-5(e)(h)		
RHR-RV-25A,B,C(e)(h)		
RHR-RV-30(e)(h)		
RHR-RV-36(e)(h)		
RHR-RV-88A,B,C(e)(h)		
RHR-FCV-64A,B,C		
Containment Atmosphere Control(c)(i) (H_2 Recombiner)		N.A.
CAC-V-2		
CAC-FCV-2A,B		
CAC-V-15		
CAC-FCV-1A,B		
CAC-V-11		

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TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	VALVE GROUP(a)	MAXIMUM ISOLATION TIME (Seconds)
d. Other Containment Isolation Valves (Continued)		
Containment Atmosphere Control(c)(i) (H_2 Recombiner) (Continued)		N.A.
CAC-V-6		
CAC-V-4		
CAC-FCV-4A,B		
CAC-V-13		
CAC-V-17		
CAC-FCV-3A,B		
CAC-V-8		
CSP-V-5		
CSP-V-6		
CSP-V-7		
Containment Purge System		N.A.
CSP-V-8		
CSP-V-9		
CSP-V-10		
Reactor Recirculation (Seal Injection)		N.A.
RRC-V-13A,B		
RRC-V-16A,B		
Containment Instrument Air		N.A.
CIA-V-20		
CIA-V-21		

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TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	VALVE GROUP(a)	MAXIMUM ISOLATION TIME (Seconds)
d. Other Containment Isolation Valves (Continued)		
Containment Instrument Air (Continued)		N.A.
CIA-V-30A,B		
CIA-V-31A,B		
Post-Accident Sampling System(c)		N.A.
PSR-V-X73-1		
PSR-V-X73-2		
PSR-V-X77A1		
PSR-V-X77A2		
PSR-V-X77A3		
PSR-V-X77A4		
PSR-V-X80-1		
PSR-V-X80-2		
PSR-V-X82-1		
PSR-V-X82-2		
PSR-V-X82-7		
PSR-V-X82-8		
PSR-V-X83-1		
PSR-V-X83-2		
PSR-V-X84-1		
PSR-V-X84-2		
PSR-V-X88-1		
PSR-V-X88-2		

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TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	VALVE GROUP(a)	MAXIMUM ISOLATION TIME (Seconds)
d. Other Containment Isolation Valves (Continued)		
Radiation Monitoring		N.A.
PI-V-X72f/1 PI-V-X73e/1		
Transversing Incore Probe System		N.A.
TIP-V-6 TIP-V-7,8,9,10,11(e)		

TABLE NOTATIONS

*But greater than 3 seconds.
#Provisions of Technical Specification 3.0.4 are not applicable.

(a) See Technical Specification 3.3.2 for the isolation signal(s) which operate each group.
(b) Valve leakage not included in sum of Type B and C tests.
(c) May be opened on an intermittent basis under administrative control.
(d) Not closed by SLC actuation signal.
(e) Not subject to Type C Leak Rate Test.
(f) Hydraulic leak test at 1.10 P_a.
(g) Not subject to Type C test. Test per Technical Specification 4.4.3.2.2
(h) Tested as part of Type A test.
(i) May be tested as part of Type A test. If so tested, Type C test results may be excluded from sum of other Type B and C tests.
(j) Reflects closure times for containment isolation only.
(k) During operational conditions 1, 2 & 3 the requirement for automatic isolation does not apply to RHR-V-8. Except that RHR-V-8 may be opened in operational conditions 2 & 3 provided control is returned to the control room, with the interlocks reestablished, and reactor pressure is less than 135 psig.
(l) The isolation logic associated with the reactor recirculation hydraulic control containment isolation valves need not meet single failure criteria for OPERABILITY for a period ending no later than May 15, 1995.

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> rectification 3.6.1.3

REACTOR COOLANT SYSTEM

3/4.4.7 MAIN STEAM LINE ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

LCO 3.6.1.3 (A.7)

3.4.7 Two main steam line isolation valves (MSIVs) per main steam line shall be OPERABLE with closing times greater than or equal to 3 and less than or equal to 5 seconds.

SR 3.6.1.3.6

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

ACTION A

a. With one or more MSIVs inoperable:

1. Maintain at least one MSIV OPERABLE in each affected main steam line that is open and within 8 hours, either: (A.4)

a) Restore the inoperable valve(s) to OPERABLE status, or (A.5)

b) Isolate the affected main steam line by use of a deactivated MSIV in the closed position. (L.2)

ACTION E

2. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

(L.3)

b. The provisions of Specification 3.0.4 are not applicable. (A.6)

add proposed ACTION B

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SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.6

4.4.7 Each of the above required MSIVs shall be demonstrated OPERABLE by verifying full closure between 3 and 5 seconds when tested pursuant to Specification 4.0.5.

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3/4.6 CONTAINMENT SYSTEMS

3/4.6.1 PRIMARY CONTAINMENT

PRIMARY CONTAINMENT INTEGRITY

See Discussion of Changes for ITS 3.6.1.1, "Primary Containment" in this Section

LIMITING CONDITION FOR OPERATION

3.6.1.1 PRIMARY CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2* and 3.

ACTION:

Without PRIMARY CONTAINMENT INTEGRITY, restore PRIMARY CONTAINMENT INTEGRITY within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.1 PRIMARY CONTAINMENT INTEGRITY shall be demonstrated:

a. After each closing of each penetration subject to Type B testing, except the primary containment air locks, if opened following Type A or B test, by leak rate testing the seals with gas at P_a, and verifying that when the measured leakage rate for these seals is added to the leakage rates determined pursuant to Surveillance Requirement 4.6.1.2.d. for all other Type B and C penetrations, the combined leakage rate is less than or equal to 0.60 L_a.

Required Actions A.2 and b. C.2, and SR 3.6.1.3.2

b. At least once per 31 days by verifying that all primary containment penetrations** not capable of being closed by OPERABLE containment automatic isolation valves and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic valves secured in position, except as provided in Table 3.6.3-1 of Specification 3.6.3., or check valve with flow secured

LA.1

SR 3.6.1.3.2

Required Actions A.2 and C.2

LA.1

LA.2

Note 1 to Actions and Note 2 to SR 3.6.1.3.2 and SR 3.6.1.3.3

c. By verifying each primary containment air lock is in compliance with the requirements of Specification 3.6.1.3.

LA.5

d. By verifying the suppression chamber is in compliance with the requirements of Specification 3.6.2.1.

---

* See Special Test Exception 3.10.1.

**Except valves, blind flanges, and deactivated automatic valves which are within the primary containment or other areas administratively controlled to prohibit access for reasons for personnel safety (i.e., radiation and temperature) and are locked, sealed, or otherwise secured in the closed position (1-1/2 inch and smaller valves connected to vents, drains or test connections must be closed but need not be sealed). Valves inside containment shall be verified closed following primary containment de-inerting, but verification is not required more often than once per 92 days. Valves in other administratively controlled areas shall be verified closed during each COLD SHUTDOWN, but verification is not required more often than once per 31 days.

LA.3

Required Actions A.2 and C.2, including Notes, and SR 3.6.1.3.3, including Note

Note 1 to SR 3.6.1.3.2 and Notes to Required Actions A.2 and C.2

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CONTAINMENT SYSTEMS

PRIMARY CONTAINMENT LEAKAGE

See Discussion of changes for ITS: 3.6.1.1, "Primary Containment," in this Section.

LIMITING CONDITION FOR OPERATION

3.6.1.2 Primary containment leakage rates shall be limited to:

a. An overall integrated leakage rate of less than or equal to L_a, 0.50 percent by weight of the containment air per 24 hours at P_a.

b. A combined leakage rate of less than or equal to 0.60 L_a for all penetrations and all valves ~~listed in Table 3.6.3-1,~~ (except for main steam line isolation valves* (and valves which are hydrostatically ~~leak tested per Table 3.6.3-1~~), subject to Type B and C tests when pressurized to P_a.

SR 3.6.1.3.11 c. ~~Less~~ (A.8) less than or equal to 11.5 scf per hour for any one main steam line isolation valve when tested at P_a, 25.0 psig.

SR 3.6.1.3.12 d. A combined leakage rate of ~~less than or equal to 1 gpm times the total number of ECCS and RCIC containment isolation valves in hydrostatically tested lines which penetrate the primary containment, when tested at 1.10 P_a~~ (LA.4)

APPLICABILITY: When PRIMARY CONTAINMENT INTEGRITY is required per Specification 3.6.1.1.

ACTION:

With:

a. The measured overall integrated primary containment leakage rate exceeding 0.75 L_a, or

b. The measured combined leakage rate for all penetrations and all valves ~~listed in Table 3.6.3-1,~~ (except for main steam line isolation valves* (and valves which are hydrostatically leak tested per Table 3.6.3-1), subject to Type B and C tests exceeding 0.60 L_a, or

Condition D c. The measured leakage rate exceeding 11.5 scf per hour for any one main steam line isolation valve, or

Condition D d. The measured combined leakage rate for all ECCS and RCIC containment isolation valves in hydrostatically tested lines which penetrate the primary containment exceeding 1 gpm times the total number of such valves, (LA.4)

restore:

a. The overall integrated leakage rate(s) to less than or equal to 0.75 L_a, and

b. The combined leakage rate for all penetrations and all valves listed in Table 3.6.3-1, except for main steamline isolation valves* and valves which are hydrostatically leak tested per Table 3.6.3-1, subject to Type B and C tests to less than or equal to 0.60 L_a, and

~~*Exemption to Appendix J of 10 CFR Part 50.~~ (A.8)

CONTAINMENT SYSTEMS

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

Required Action D.1

c. The leakage rate to less than or equal to 11.5 scf per hour for any one main steam line isolation valve, and

d. The combined leakage rate for all ECCS and RCIC containment isolation valves in hydrostatically tested lines which penetrate the primary containment to less than or equal to 1 gpm times the total number of such valves,

prior to increasing reactor coolant system temperature above 200°F. M.2

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.11 and SR 3.6.1.3.12

4.6.1.2 Perform required primary containment leakage rate testing in accordance with the Primary Containment Leakage Rate Testing Program described in Specification 6.8.4.f.

a. Deleted

b. Deleted

c. Deleted

d. Deleted

e. Deleted

f. Deleted

g. Deleted

h. Deleted

i. Deleted

j. Deleted

add proposed SR 3.6.1.3.10 M.3

B

Specification 3.6.1.3

CONTAINMENT SYSTEMS

DRYWELL AND SUPPRESSION CHAMBER PURGE SYSTEM

LIMITING CONDITION FOR OPERATION

LCO 3.6.1.3

3.6.1.8 The drywell and suppression chamber purge system may be in operation with the drywell and/or suppression chamber purge supply and exhaust butterfly isolation valves open for inerting, deinerting, or pressure control. ~~PURGING through the Standby Gas Treatment System~~ shall be restricted to less than or equal to 90 hours per 365 days.

A.7

L.11

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

Actions A and B

a. With a drywell and/or suppression chamber purge supply and/or exhaust butterfly isolation valve open for other than inerting, deinerting, or pressure control, close the butterfly valve(s) within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

L.11

Action E

4

L.1

One valve in line open

b. With a drywell and suppression chamber purge supply and/or exhaust isolation valve(s) with resilient material seals having a measured leakage rate exceeding 0.05 L_a per valve test, and the leakage added to the previously determined total for all valves and penetrations subject to Type B and C tests per LCO 3/4.6.1.2 is less than 0.6 L_a, secure the valves in the closed position and perform maintenance at the next plant cold shutdown to reduce leakage to within 4.6.1.8.1.a, otherwise, restore the inoperable valve(s) to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

A.9

SURVEILLANCE REQUIREMENTS

4.6.1.8.1 At least once per 6 months, on a STAGGERED TEST BASIS, each 24- and 30-inch drywell and suppression chamber purge supply and exhaust isolation valve with resilient material shall be demonstrated OPERABLE by verifying that the measured leakage is:

A.9

a. Less than or equal to 0.05 L_a per valve test or,

b. Greater than 0.05 L_a per valve test, the leakage added to the previously determined total for all valves and penetrations subject to Type B and C tests per LCO 3/4.6.1.2 shall be less than 0.6 L_a,

c. In the event the valves are to be operated, and 4.6.1.8.1.a. has been exceeded, a leakage test must be performed within 24 hours following operation, to ensure compliance with 0.6 L_a.

add proposed SR 3.6.1.3.1

M.3

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Specification 3.6.1.3

SURVEILLANCE REQUIREMENTS (Continued)

4.6.1.8.2 The cumulative time that the drywell and suppression chamber purge system has been in operation PURGING through the Standby Gas Treatment System shall be verified to be less than or equal to 90 hours per 365 days prior to use in this mode of operation.

L.11

DISCUSSION OF CHANGES
ITS: 3.6.1.3 - PRIMARY CONTAINMENT ISOLATION VALVES

ADMINISTRATIVE

A.1 Proposed LCO 3.6.1.3 applies to each PCIV, except reactor building-to-suppression chamber vacuum breakers. LCO 3.6.1.6 covers these vacuum breakers and thus, they do not need to be considered in this LCO. Since the requirement is still maintained, this change is considered administrative. | B

A.2 This proposed Note ("Separate Condition entry is allowed for each penetration flow path") provides explicit instructions for proper application of the ACTIONS for Technical Specification compliance. In conjunction with the proposed Specification 1.3, "Completion Times," this Note provides direction consistent with the intent of the existing ACTIONS for inoperable isolation valves.

A.3 The proposed ACTIONS include Notes 3 and 4. These Notes facilitate the use and understanding of the intent. Any system made inoperable by inoperable PCIVs is to have its ACTIONS also apply. This requirement is currently located in ACTIONS a.4 and b.2, but it does not cover all situations. Therefore, Note 3 has been added to cover all situations. Note 4 clarifies that these "systems" include the primary containment. With the proposed LCO 3.0.6, this intent would not necessarily apply. The clarification is consistent with the intent and interpretation of the existing Technical Specifications, and is therefore considered administrative.

A.4 Proposed Condition A applies if the affected penetration has two valves, and only one is inoperable. This inherently ensures maintaining "at least one isolation valve OPERABLE." In the case of containment penetrations designed with only one isolation valve, the system boundary is considered an adequate barrier and the penetration is not considered "open" when the single isolation valve is open.

A.5 The revised presentation of ACTIONS (based on the BWR Standard Technical Specifications, NUREG-1434) does not explicitly detail options to "restore...to OPERABLE status." This action is always an option, and is implied in all ACTIONS. Omitting this action is purely editorial.

A.6 The LCO 3.0.4 statement has been deleted since proposed LCO 3.0.4 provides this allowance (i.e., this allowance has been moved to LCO 3.0.4). The LCO 3.0.3 statement has been deleted since it is redundant to the "Otherwise" action. That is, LCO 3.0.3 is not applicable anyway since a shutdown action has been provided. Therefore, deletion of these allowances is administrative.

TECHNICAL CHANGES - MORE RESTRICTIVE

M.2 (cont'd) If leakage is discovered while shutdown, proposed ACTION D does not allow continued operations, similar to the current requirement. The MSIV and hydrostatically tested valves ACTIONS would allow continued operation if the valves are closed, but only if overall primary containment leakage were within Specifications. This is consistent with the accident analysis. Therefore the proposed presentation and associated ACTIONS for containment leakage rate beyond limits will result in establishing and maintaining the reactor in a cold shutdown, all-rods-in, condition until the leakage is corrected; resulting in increased safety to the allowances of the existing ACTION.

M.3 Two new Surveillance Requirements have been added. The first Surveillance Requirement (SR 3.6.1.3.1) verifies the 24 and 30 inch purge valves are closed every 31 days. The second Surveillance Requirement (SR 3.6.1.3.10) ensures the secondary containment bypass leakage is within limits at a Frequency in accordance with the Primary Containment Leakage Rate Testing Program. These SRs are an additional restriction on plant operation. 1B

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The list of primary containment isolation valves are proposed to be relocated to the Licensee Controlled Specifications Manual consistent with Generic Letter 91-08. The listing of valves which are subject to leakage testing are related to design and are not necessary for ensuring the primary containment is maintained OPERABLE. Specification 3.6.1.3 requires each PCIV to be OPERABLE. These requirements are adequate for ensuring each required PCIV is maintained OPERABLE. Changes to the Licensee Controlled Specifications Manual will be controlled by the provisions of 10 CFR 50.59.

LA.2 Requirements on the replacement charges for explosive valves are proposed to be relocated to the Bases. These details are not necessary to ensure that the traversing in-core probe (TIP) system explosive isolation valves are maintained OPERABLE. The requirements of Specification 3.6.1.3, SR 3.6.1.3.4, and SR 3.6.1.3.9 are adequate to ensure the OPERABILITY of the TIP system explosive isolation valves. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications. 1B

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

LA.3 The requirement that the valves in the primary containment and other administratively controlled areas (e.g., high radiation areas) must also be locked, sealed, or otherwise secured in position to exempt the monthly, "hands-on" valve position surveillance check is proposed to be relocated to plant procedures. The primary containment and other administratively controlled areas are sufficiently controlled to minimize the potential of a mispositioned valve. The entrances to these areas are normally locked closed to preclude an inadvertent entry into the area during MODES 1, 2, and 3. Therefore, this requirement is not necessary for inclusion in the Technical Specifications. Changes to the related requirements in procedures will be controlled by the provisions of 10 CFR 50.59. The remaining controls provided in the proposed Technical Specifications are consistent with the BWR Standard Technical Specifications, NUREG-1434.

LA.4 The combined leakage rate limit and the test pressure of the valves in hydrostatically tested lines are proposed to be relocated to the Bases. These details are not necessary for ensuring the valves are leak tested. The leakage from these valves are not included in the overall type A leakage limits, nor is the leakage from these valves assumed in any design basis calculations relating to offsite dose releases. The requirements of SR 3.6.1.3.12 are adequate to ensure the leakage tests are conducted at the proper pressure and the leakage rates are within the limit. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LD.1 The Frequencies for performing current Surveillances 4.6.3.2, 4.6.3.4, and 4.6.3.5.b, (proposed SRs 3.6.1.3.7, 3.6.1.3.8, and 3.6.1.3.9) have been extended from 18 months to 24 months to facilitate a change to the WNP-2 maintenance cycle from 12 months to 24 months. The current conditions in the northwest require that WNP-2 shut down each spring for an annual maintenance and refueling outage. Currently, most of the current Surveillances that are required to be performed on an 18 month interval are performed annually because they must be performed while the plant is shut down. This has resulted in increased testing, with a resultant increase in cost and personnel exposure, with no comparable increase in reliability or safety. This change is being proposed to support limiting the amount of surveillance testing that must be performed each maintenance and refueling outage. The proposed change will allow these Surveillances to extend their Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed Specification 3.0.2). This proposed change was evaluated in

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd) accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991. Reviews of historical maintenance and surveillance data have shown that these tests normally pass their Surveillances at the current Frequency. An evaluation has been performed using this data, and it has been determined that the effect on safety due to the extended Surveillance Frequency will be small. In addition, the proposed 24 month Surveillance Frequencies, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) do not invalidate any assumptions in the plant licensing basis.

"Specific"

L.1 The current TS repeat most of the requirements, provisions, and ACTIONS for MSIVs in a separate Specification (3/4.4.7) from all other PCIVs (see Comment A.7); however, the restoration time for MSIVs is 8 hours, while only 4 hours for PCIVs. The proposed TS incorporate the MSIV requirements and associated restoration times into the PCIV TS, and resolves the conflict by adopting the 8 hour allowance. In addition, the time allowed to close an open purge valve has been extended from 1 hour to 4 hours, consistent with the other PCIVs (except MSIVs). These valves are fully qualified to close under accident conditions.

L.2 Current ACTIONS list some, but not all, possible acceptable isolation devices that may be used to satisfy the need to isolate a penetration with an inoperable isolation valve. The proposed change provides a complete list of acceptable isolation devices. Since the result of the ACTION continues to be an acceptably isolated penetration for continued operation, the proposed change does not adversely affect safe operation.

Many penetrations are designed with check valves as acceptable isolation barriers. With forward flow in the line secured, a check valve is essentially equivalent to a closed manual valve. For those penetrations designed with check valves as acceptable isolation devices, this proposed change provides an equivalent level of safety. For penetrations not designed with check valves for isolation, the proposed change does not affect the requirements to isolate with a closed deactivated automatic valve or closed manual valve.

ACTIONS allowing closed manual valves or check valves with flow secured also apply to isolating main steam lines, even though the design does not provide for these type of isolation devices. This change is simply a result of simplicity in providing a consistent presentation for all penetrations. While this apparent flexibility does not result in any actual technical change in the Technical Specifications, it is listed here for completeness.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.3 In the event both valves in a penetration are inoperable, the existing Specification, which requires maintaining one isolation valve OPERABLE, would not be met and an immediate shutdown is required. Proposed ACTION B provides 1 hour prior to commencing a required shutdown. This proposed 1 hour period is consistent with the existing time allowed for conditions when the primary containment is inoperable. The proposed change will provide consistency in ACTIONS for these various containment degradations.

L.4 In the event the inoperable valve is an excess flow check valve, the proposed time to allow for restoration prior to requiring a shutdown is 12 hours. In this event, a limiting event would still be assumed to be within the bounds of the safety analysis (the excess flow lines contain orifices and are approximately 1 inch in diameter.) Allowing an extended restoration time, to potentially avoid a plant transient caused by the forced shutdown, is reasonable based on the probability of a EFCV line break event and does not represent a significant decrease in safety.

L.5 An allowance is proposed for intermittently opening, under administrative control, closed primary containment isolation valves (other than those currently allowed to be opened using ACTIONS footnote *). The allowance is presented in proposed ACTIONS Note 1, and in Note 2 to SR 3.6.1.3.2 and SR 3.6.1.3.3. Opening of primary containment penetrations on an intermittent basis is required for performing surveillances, repairs, routine evolutions, etc.

L.6 Any time the OPERABILITY of a system or component has been affected by repair, maintenance, or replacement of a component, post maintenance testing is required to demonstrate OPERABILITY of the system or component. After restoration of a component that caused a required SR to be failed, SR 3.0.1 requires the appropriate SRs (in this case SR 3.6.1.3.5 and SR 3.6.1.3.6, as applicable) to be performed to demonstrate OPERABILITY of the affected components. Therefore, explicit post maintenance Surveillance Requirements are not required and have been deleted from the Technical Specifications. Entry into the applicable MODES without performing this post maintenance testing also continues to be allowed, as discussed in the Bases for proposed SR 3.0.1.

L.7 The proposed surveillance (for a functional test of each primary containment isolation valve) does not include the restriction on plant conditions that requires the Surveillance to be performed during Cold Shutdown or Refueling. Some isolation valves could be adequately tested in other than Cold Shutdown or Refueling, without jeopardizing safe plant operations. The control of the plant conditions appropriate to perform the test is an issue for procedures and scheduling, and has been determined by the NRC Staff to be unnecessary as a Technical Specification restriction.

TECHNICAL CHANGES - LESS RESTRICTIVE

L.7 (cont'd) As indicated in Generic Letter 91-04, allowing this control is consistent with the vast majority of other Technical Specification Surveillances that do not dictate plant conditions for the Surveillance.

L.8 The phrase "actual or," in reference to the automatic isolation signal, has been added to the Surveillance Requirement for verifying that each PCIV actuates on an automatic isolation signal. This allows satisfactory automatic PCIV isolations for other than Surveillance purposes to be used to fulfill the Surveillance Requirements. OPERABILITY is adequately demonstrated in either case since the PCIV itself cannot discriminate between "actual" or "test" signals.

L.9 Current Surveillance 4.6.3.4 requires each excess flow check valve (EFCV) to check flow at > 10 psid for hydraulic service valves and > 15 psid for pneumatic service valves. The requirement to check flow and the psid limit has been deleted. Proposed SR 3.6.1.3.8 now requires the EFCVs to actuate to their isolation position (i.e., closed) on an actual or simulated instrument line break signal. The requirements for the EFCVs are provided in 10 CFR 50 Appendix A, GDCs 55 and 56, and as further detailed in Regulatory Guide 1.11. These requirements state that there should be a high degree of assurance that the EFCVs will close or be closed if the instrument line outside containment is lost during normal reactor operation, or under accident conditions. The current differential pressure limits for the EFCVs are the manufacturers design capabilities. During normal operation, the hydraulic service EFCVs would experience full reactor pressure of 1035 psig. During accident conditions (DBA LOCA), primary containment pressure of up to 35 psig would be available to close the pneumatic service EFCVs. Therefore, the design values have been deleted. In their place, the actual test conditions for the two type of EFCVs have been added to the Bases. The requirement to "check flow" has also been deleted. The Instrument Line Break Analysis in the WNP-2 FSAR assumes both the EFCV and the manual block valve to be unavailable, i.e., fail to close; the accident is terminated by cooling down the plant. Therefore, since the actual leakage is not an assumption of the accident analysis (the leakage is assumed to be the maximum allowed through the broken line), the leakage limit (i.e., check flow) has been deleted.

L.10 Not used. (B)

L.11 The time limitations applied to opening the primary containment purge valves are replaced with specific criteria for opening. The time limits were based on engineering judgement and/or early plant operating experience, and not based on any analytical requirement. The proposed limits on when the valves are permitted to be open, provided in Note 2 to proposed SR 3.6.1.3.1, will ensure appropriate controls. The new limits will now allow the valves to

TECHNICAL CHANGES - LESS RESTRICTIVE

L.11 (cont'd) be open for ALARA or air quality considerations for personnel entry, as well as for Surveillances that require the valves to be open. Thus, use of the system will still continue to be minimized and limited to safety related reasons. The operating history indicates that these valves are only opened for the specified reasons and for cumulative periods that are generally less than the current allowed cumulative times. In addition, these valves are fully qualified to close in the required time under accident conditions.

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Specification 3.6.1.8

MSIV LEAKAGE CONTROL SYSTEM

LIMITING CONDITION FOR OPERATION

LCO 3.6.1.8

3.6.1.4 Two independent (LA.1) MSIV leakage control system (LCS) subsystems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

Action A / Action C: With one MSIV leakage control system subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

add proposed Action B (L.1)

SURVEILLANCE REQUIREMENTS

4.6.1.4 Each MSIV leakage control system subsystem shall be demonstrated OPERABLE:

a. At least once per 31 days by:

SR 3.6.1.8.1 1. Starting the blower(s) ~~from the control room~~ and operating the blower(s) for at least 15 minutes. (LA.2)

SR 3.6.1.8.2 2. Verify continuity of heaters (LA.2) Energizing the heaters and verifying the current to be ± 10% of rated current for each heater.

b. During each COLD SHUTDOWN, if not performed within the previous 92 days, by cycling each depressurizing valve and steam isolation valve through at least one complete cycle of full travel. (LA.3)

c. At least once per 18 months by:

1/B

SR 3.6.1.8.3 1. Performance of a functional test which includes simulated actuation of the subsystem throughout its operating sequence, and verifying that each automatic valve actuates to its correct position and the blower starts. (LA.2)

2. Verifying that the blower develops at least the -17" H_2O at the blower suction, with 30 (3016) cfm of dilution flow. (L.2)

d. By verifying the ~~flow, pressure and temperature instrumentation~~ to be OPERABLE by performance of a:

1. CHANNEL FUNCTION TEST at least once per 31 days, and
2. CHANNEL CALIBRATION at least once per 18 months.

(LC.1)

Page 1 of 1

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.3 (cont'd) in the TS, and are proposed to be relocated to the IST Program. Changes to the IST Program will be controlled by the provisions of 10 CFR 50.59.

LC.1 The MSLC System instrumentation does not necessarily relate directly to the OPERABILITY of the system. The BWR Standard Technical Specifications, NUREG-1434, does not specify indication-only equipment to be OPERABLE to support OPERABILITY of a system or component. Control of the availability of, and necessary compensatory activities if not available, for indications and monitoring instrumentation are addressed by plant operational procedures and policies. In addition, the system functional test required by proposed SR 3.6.1.8.3 will ensure that necessary controls will function properly. Therefore, this instrumentation is proposed to be relocated to plant procedures. Changes to the relocated requirements in procedures will be controlled by the provisions of 10 CFR 50.59. B

"Specific"

L.1 A new ACTION has been provided when both MSLC subsystems are inoperable. Proposed ACTION B will allow 7 days to restore one of the two subsystems to OPERABLE status. Currently, an LCO 3.0.3 entry is required (which will then require an immediate plant shutdown). The MSLC System is judged to be of low safety significance since the MSIVs are required to meet specific leakage criteria and the system serves to filter only a small portion of the complete primary containment leakage following an accident. Several Studies have documented the minimal impact of increased unfiltered primary containment leakage; among these are NUREG-1273, "Technical Findings and Regulatory Analysis for Generic Safety Issue II.E.4.3, Containment Integrity Check," and NUREG/CR-3539, "Impact of Containment Building Leakage on LWR Accident Risk." These documents indicate that leakage rate increases significantly in excess of the allowed MSIV leakage rates would not result in significant increase in risk to the public. Therefore, a 7 day allowed outage time for when both subsystems are inoperable is considered appropriate.

L.2 In addition to relocating the specifics of the Surveillances to the Bases, the dilution flow corresponding to at least -17" H_2O at the suction blower is being changed from 30 cfm to 30 ± 6 cfm. As stated in the current Bases, page B 3/4 6-2, the subsystems are required "to accommodate a leak rate of five times the Technical Specification leakage allowed for the MSIVs while maintaining a negative pressure downstream of the MSIVs." The allowed Technical Specification leakage is 11.5 scfh per valve. Five times the Technical Specification value for all four steam lines is a total of 230 scfh (3.8 scfm). Besides maintaining adequate vacuum with the blower, the blower dilution flow is also required to dilute

TECHNICAL CHANGES - LESS RESTRICTIVE

L.2 (cont'd) the leakage drawn off to the point where given worst case flow, temperature and humidity dilution is such that the process stream delivered to the SGT is within the SGT capacity. Accepting flow values of between 24 to 36 cfm provides adequate margin to the flow necessary to create sufficient vacuum to maintain proper operation of the MSLC System (design specification value of five times the Technical Specification allowed leakage) and is sufficient to maintain adequate margin to preserve blower operation given worst case conditions of flow, temperature and humidity. The proposed band (30 ± 6 cfm) is adequate to meet the design requirements for leakage accommodation (maintaining a sufficient vacuum) and blower fan cooling. It is necessary to request a band of flow values because the measurement of the flow rate is not precise enough to consistently measure 30 cfm and a band should be specified in order to maintain compliance with theWNP-2 Technical Specifications. Additionally, the minimum flow, 24 cfm, has enough margin above the design required flow so that degrading conditions will be recognized and corrective actions initiated before the flow can degrade below the design requirements.

Specification 3.6.3.2

M.1

Insert New Specification 3.6.3.2

Insert new Specification 3.6.3.2, "Primary Containment Atmosphere Mixing System," as shown in the WNP-2 Improved Technical Specifications. 1 B

DISCUSSION OF CHANGES
ITS: 3.6.3.2 - PRIMARY CONTAINMENT ATMOSPHERE MIXING SYSTEM

ADMINISTRATIVE

None

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 A new Specification requiring two primary containment atmosphere mixing subsystems (head area return fans) to be OPERABLE is being added. Appropriate ACTIONS and a Surveillance Requirement are also added, consistent with the BWR Standard Technical Specifications, NUREG-1434.

TECHNICAL CHANGES - LESS RESTRICTIVE

None

Specification 3.6.4.1

CONTAINMENT SYSTEMS

3/4.6.5 SECONDARY CONTAINMENT

SECONDARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

LCO 3.6.4.1
3.6.5.1 SECONDARY CONTAINMENT ~~INTEGRITY~~ (A.1) shall be ~~maintained~~ OPERABLE (A.1)

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, and *.

ACTION:

Without SECONDARY CONTAINMENT ~~INTEGRITY~~ OPERABLE (A.1)

a. ACTION A { In OPERATIONAL CONDITION 1, 2, or 3, restore SECONDARY CONTAINMENT ~~INTEGRITY~~ within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. } (A.1) to OPERABLE status

b. ACTION C In OPERATIONAL CONDITION *, suspend handling of irradiated fuel in the secondary containment, CORE ALTERATIONS and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.5.1 SECONDARY CONTAINMENT INTEGRITY shall be demonstrated by:

SR 3.6.4.1.1 a. Verifying at least once per 24 hours that the pressure within the secondary containment is less than or equal to 0.25 inch of vacuum water gauge.

b. Verifying at least once per 31 days that:

SR 3.6.4.1.2 1. All secondary containment equipment hatches ~~and blowout panels~~ (A.1) (B) are closed and sealed. (A.2)

SR 3.6.4.1.3 2. At least one door in each access to the secondary containment is closed.

(A.3) 3. All secondary containment penetrations not capable of being closed by OPERABLE secondary containment automatic isolation dampers/valves and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic dampers/valves secured in position. — moved to LCO 3.6.4.2

c. At least once per ~~18~~ 24 (LD.1) months ON A STAGGERED TEST BASIS (M-1)

SR 3.6.4.1.4 1. Verifying that one standby gas treatment subsystem will draw down the secondary containment to greater than or equal to 0.25 inch of vacuum water gauge in less than or equal to 120 seconds, and

SR 3.6.4.1.5 2. Operating one standby gas treatment subsystem for 1 hour and maintaining greater than or equal to 0.25 inch of vacuum water gauge in the secondary containment at a flow rate not exceeding 2240 cfm.

APPLICABILITY *When irradiated fuel is being handled in the secondary containment and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

DISCUSSION OF CHANGES
ITS: 3.6.4.1 - SECONDARY CONTAINMENT

ADMINISTRATIVE

A.1 The definition of SECONDARY CONTAINMENT INTEGRITY has been deleted from the proposed Technical Specifications. It is replaced with the requirement for secondary containment to be OPERABLE. This was done because of the confusion associated with these definitions compared to its use in the respective LCO. The change is editorial in that all the requirements are specifically addressed in the proposed LCO for the secondary containment and in the Secondary Containment Isolation Valves and Standby Gas Treatment System Specifications. Therefore the change is a presentation preference adopted by the BWR Standard Technical Specifications, NUREG-1434.

A.2 The requirement to verify that one door in each access opening is closed (current Specification 4.6.5.1.b.2) has been modified to require each inner door or each outer door to be closed. The WNP-2 design includes more than two doors on some of the access openings. The current WNP-2 interpretation of this requirement is that all inner doors or all outer doors must be closed, whenever an access opening has more than two doors. Therefore, this change is a clarification of current practice, and as such, is administrative in nature.

A.3 This requirement, relating to the position of secondary containment isolation valves, has been moved to Specification 3.6.4.2, "Secondary Containment Isolation Valves," in accordance with the format of the BWR Standard Technical Specifications, NUREG-1434. Any technical changes to this requirement will be addressed with the content of proposed Specification 3.6.4.2.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 The current Surveillance requires that one subsystem be tested every 18 months. However, the same SGT subsystem could be tested every outage. The proposed Specification will now require both subsystems be tested in the course of two outages - as represented by the Staggered Test Basis requirement of the Frequency. This is an additional restriction on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The requirement that all blowout panels must be verified closed and sealed every 31 days is proposed to be relocated to plant procedures. The blowout panels are passive devices installed as

B

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.1 (cont'd) part of the walls of the secondary containment; they are not manipulated during plant operation nor used for personnel or equipment access. Any severe damage to the blowout panels would be evident when the secondary containment pressure could not be maintained. Currently, the secondary containment pressure is required to be verified within the limits every 24 hours. This requirement is maintained in proposed SR 3.6.4.1.1. Therefore, this requirement is not necessary for inclusion in the Technical Specifications. Changes to the relocated requirements in procedures will be controlled by the provisions of 10 CFR 50.59. (B)

LD.1 The Frequencies for performing current Surveillances 4.6.5.1.c.1 and 4.6.5.1.c.2 (proposed SRs 3.6.4.1.4 and 3.6.4.1.5) have been extended from 18 months to 24 months to facilitate a change to the WNP-2 maintenance cycle from 12 months to 24 months. The current conditions in the northwest require that WNP-2 shut down each spring for an annual maintenance and refueling outage. Currently, most of the current Surveillances that are required to be performed on an 18 month interval are performed annually because they must be performed while the plant is shut down. This has resulted in increased testing, with a resultant increase in cost and personnel exposure, with no comparable increase in reliability or safety. This change is being proposed to support limiting the amount of surveillance testing that must be performed each maintenance and refueling outage. The proposed change will allow these Surveillances to extend the Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed Specification 3.0.2). This proposed change was evaluated in accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991. Reviews of historical maintenance and surveillance data have shown that these tests normally pass their Surveillances at the current Frequency. An evaluation has been performed using this data, and it has been determined that the effect on safety due to the extended Surveillance Frequency will be small. In addition, the proposed 24 month Surveillance Frequencies, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) do not invalidate any assumptions in the plant licensing basis.

"Specific"

None

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Specification 3.6.4.2

CONTAINMENT SYSTEMS

3/4.6.5 SECONDARY CONTAINMENT

SECONDARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.5.1 SECONDARY CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, and *.

ACTION:

Without SECONDARY CONTAINMENT INTEGRITY:

a. In OPERATIONAL CONDITION 1, 2, or 3, restore SECONDARY CONTAINMENT INTEGRITY within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION *, suspend handling of irradiated fuel in the secondary containment, CORE ALTERATIONS and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.5.1 SECONDARY CONTAINMENT INTEGRITY shall be demonstrated by:

a. Verifying at least once per 24 hours that the pressure within the secondary containment is less than or equal to 0.25 inch of vacuum water gauge.

b. Verifying at least once per 31 days that:

1. All secondary containment equipment hatches and blowout panels are closed and sealed.

2. At least one door in each access to the secondary containment is closed.

3. All secondary containment penetrations not capable of being closed by OPERABLE secondary containment automatic isolation dampers/valves and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic dampers/valves secured in position.

c. At least once per 18 months:

1. Verifying that one standby gas treatment subsystem will draw down the secondary containment to greater than or equal to 0.25 inch of vacuum water gauge in less than or equal to 120 seconds, and

2. Operating one standby gas treatment subsystem for 1 hour and maintaining greater than or equal to 0.25 inch of vacuum water gauge in the secondary containment at a flow rate not exceeding 2240 cfm.

*When irradiated fuel is being handled in the secondary containment and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

L.6 — add Proposed Required Action A.2 Note and SR 3.6.4.2.1 Note

Required Action A.2 and SR 3.6.4.2.1

SR 3.6.4.2.1

Required Action A.2

add proposed SR 3.6.4.2.1 Note 2

L.1

See Discussion of Changes for ITS 3.6.4.1, "Secondary Containment," in this section.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

"Specific"

L.1 An allowance is proposed for intermittently opening closed secondary containment isolation valves under administrative control as is allowed in the existing primary containment Technical Specifications. The allowance is presented in proposed ACTIONS Note 1 and SR 3.6.4.2.1 Note 2. Opening of secondary containment penetrations on a intermittent basis is required for many of the same reasons as primary containment penetrations and the potential impact on consequences is less significant. 1B

L.2 In the event both valves in a penetration are inoperable, the existing Specification, which requires maintaining one isolation valve OPERABLE, would not be met and an immediate shutdown is required. The proposed ACTIONS for the secondary containment penetrations provide 4 hours prior to commencing a required shutdown. This proposed 4 hour period is consistent with the existing time allowed for conditions when the secondary containment is inoperable. The proposed change will provide consistency in ACTIONS for these various secondary containment degradations.

L.3 Any time the OPERABILITY of a system or component has been affected by repair, maintenance, or replacement of a component, post maintenance testing is required to demonstrate OPERABILITY of the system or component. After restoration of a component that caused a required SR to be failed, SR 3.0.1 requires the appropriate SRs (in this case SR 3.6.4.2.2) to be performed to demonstrate the OPERABILITY of the affected components. Therefore, explicit post maintenance Surveillance Requirements are not required and have been deleted from the Technical Specifications. Entry into the applicable MODES without performing this post maintenance testing also continues to be precluded, as discussed in the Bases for proposed SR 3.0.1.

L.4 The proposed Surveillance for a functional test of each secondary containment isolation valve does not include the restriction on plant conditions that requires the Surveillance to be performed during Cold Shutdown or Refueling. Some isolations could be adequately tested in other than Cold Shutdown or Refueling, without jeopardizing plant operations. The control of the plant conditions appropriate to perform the test is an issue for procedures and scheduling, and has been determined by the NRC Staff to be unnecessary as a Technical Specification restriction. As indicated in Generic Letter 91-04, allowing this control is consistent with the vast majority of other Technical Specification Surveillances that do not dictate plant conditions for the Surveillance.

PLANT SYSTEMS

Specification 3.7.3

3/4.7.2 CONTROL ROOM EMERGENCY FILTRATION SYSTEM

LIMITING CONDITION FOR OPERATION

LCO 3.7.3

3.7.2 Two independent (LA.1) control room emergency filtration system trains shall be OPERABLE.

APPLICABILITY: All OPERATIONAL CONDITIONS and *. (L.1)

ACTION:

a. In OPERATIONAL CONDITION 1, 2, or 3 with one control room emergency filtration train inoperable, restore the inoperable train to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. (Action A / Action B) (A.2) add proposed ACTION D (B)

b. In OPERATIONAL CONDITION 4, 5 or *: (L.1)

1. With one control room emergency filtration train inoperable, restore the inoperable train to OPERABLE status within 7 days or initiate and maintain operation of the OPERABLE train in the pressurization mode of operation. (Action A / Action C) (L.1) add proposed Required Actions C.2.1, C.2.2, and C.2.3

2. With both control room emergency filtration trains inoperable, suspend CORE ALTERATIONS, handling of irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel. (Action E) initiate action to suspend (A.1)

c. The provisions of Specification 3.0.3 are not applicable in OPERATIONAL CONDITION *. (Actions C and E Note) (B)

SURVEILLANCE REQUIREMENTS

4.7.2 Each control room emergency filtration system train shall be demonstrated OPERABLE:

a. At least once per 12 hours by verifying that the control room air temperature is less than or equal to 85°F. (A.3) moved to LCO 3.7.4

b. At least once per 31 days on a STAGGERED TEST BASIS (L.2) by initiating from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the train operates for at least 10 hours with the heaters OPERABLE (operating) (A.4) (LA.2) (SR 3.7.3.1)

*When irradiated fuel is being handled in the secondary containment.

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DISCUSSION OF CHANGES
ITS: 3.7.3 - CONTROL ROOM EMERGENCY FILTRATION (CREF) SYSTEM

ADMINISTRATIVE

A.1 The existing ACTION to immediately "suspend operations with a potential for draining the reactor vessel" may not be possible for all plant conditions. In such a condition, the existing ACTION results in "non-compliance with the Technical Specifications" and a requirement for an LER. The intent of the ACTION is more appropriately presented in proposed Required Action E.3. With the proposed Required Action, a requirement to immediately initiate action to suspend OPDRVs is imposed. Included in this Required Action is the understanding that best efforts to suspend OPDRVs must continue until they are suspended, which is how the current ACTION is implemented. However, with this Required Action, if the suspension of OPDRVs cannot be accomplished immediately, no LER will be required. (B)

This interpretation of the ACTIONS intent is supported by the BWR Standard Technical Specifications, NUREG-1434. Because this is an enhanced presentation of existing intent, the proposed change is considered administrative.

A.2 A new ACTION is added that directs entry into LCO 3.0.3 if both CREF subsystems are inoperable in MODE 1, 2, or 3. This avoids confusion as to the proper ACTION if in MODE 1, 2, or 3 and simultaneously in a special condition, such as handling irradiated fuel assemblies in the secondary containment. Since this ACTION results in the same ACTION as the current Technical Specifications, this change is administrative.

A.3 This requirement is being moved to Specification 3.7.4 in accordance with the format of the BWR Standard Technical Specifications, NUREG-1434. Any technical changes to this requirement will be addressed in the Discussion of Changes for ITS: 3.7.4. (B)

A.4 The Surveillance Requirement for the heaters is revised from OPERABLE to operating. It is necessary for the heaters to actually operate (cycle properly when required) to reduce moisture from the adsorbers and HEPA filters. No change in actual operating practice is intended. Therefore, this change is considered administrative.

A.5 This requirement is being moved to Specification 5.5.7 in accordance with the format of the BWR Standard Technical Specifications, NUREG-1434. Any technical changes to this requirement will be addressed in the Discussion of Changes for ITS: 5.5. A Surveillance Requirement is added (proposed SR 3.7.3.2) to clarify that the tests of the Ventilation Filter Testing Program must also be completed and passed for determining OPERABILITY of the CREF System. Since this is a presentation preference that maintains current requirements, this change is considered administrative. (B)

DISCUSSION OF CHANGES
ITS: 3.7.7 - SPENT FUEL STORAGE POOL WATER LEVEL

ADMINISTRATIVE

A.1 The Applicability of this Specification is limited to circumstances when irradiated fuel assemblies are being moved in the spent fuel storage pool. This is consistent with the current ACTION, which only requires suspension of fuel movement and crane operations with loads (In addition, the relocation of crane operations with loads is specifically discussed in LA.1 below). Thus, the spent fuel pool water level is not required to be maintained within the limit as long as fuel movement is suspended. With fuel movement suspended, fuel pool level can be outside the limits for an unlimited amount of time. This is acceptable since the purpose of the Specification is to ensure sufficient water is above the irradiated fuel assemblies to meet the assumptions of a fuel handling accident. With no fuel being handled, a fuel handling accident cannot occur. Therefore, since the current Specification already allows continued operation with the spent fuel pool water level not within the limit (provided fuel handling is suspended), this change is considered administrative. (B)

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

None

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The discussions of "and crane operations with loads" (in the current ACTION) are proposed to be relocated to plant procedures since the movement of loads other than fuel assemblies is administratively controlled based on the heavy loads analysis. The bounding design basis fuel handling accident assumes an irradiated fuel assembly is dropped onto an array of irradiated fuel assemblies seated within the RPV. The movement of other loads over irradiated fuel assemblies is administratively controlled based on available analysis for the individual load. The load analysis methodology and crane operation which dictate the controls are described in the FSAR. Changes to the FSAR and relocated requirements in procedures will be controlled by the provisions of 10 CFR 50.59.

LA.2 Details of the methods for performing this ACTION (after placing the fuel assemblies in a safe condition) are proposed to be relocated to the Bases. The allowance to place fuel assemblies in a safe condition prior to suspending fuel movement is not necessary for assuring, in the case of spent fuel water level not

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.2 (cont'd) within limits, actions are taken to preclude a spent fuel handling accident from occurring. Proposed Required Action A.1 is adequate to preclude a spent fuel handling accident from occurring. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

"Specific"

None

ELECTRICAL POWER SYSTEMS

SURVEILLANCE REQUIREMENTS (Continued)

b. By checking for and removing accumulated free water in the diesel fuel tanks as follows:

SR 3.8.1.5 1. Check for and drain any accumulated water from the day tanks at least once per 31 days and after each occasion when the diesel is operated for greater than 1 hour. (L.13)

2. Check for accumulated water at the bottom of the storage tank below the transfer pump every 31 days. Initiate the procedure for pumping off accumulated water within 48 hours of detection.

c. By sampling new diesel fuel in accordance with ASTM D4057-81 prior to addition to the storage tanks and: (A.2)

1. By verifying in accordance with the tests specified in ASTM D975-81 prior to addition to the storage tanks that the sample has: moved to LCO 3.8.3

a. 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 greater than or equal to 0.83 but less than or equal to 0.89 or an API gravity at 60°F of greater than or equal to 27 degrees but less than or equal to 39 degrees.

b. A kinematic viscosity at 40°C of greater than or equal to 1.9 centistokes, but less than or equal to 4.1 centistokes, if gravity was not determined by comparison with the supplier's certification.

c. A flash point equal to or greater than 125°F, and

d. A water and sediment content of less than or equal 0.05 volume percent per ASTM D1796-83 or a Clear and Bright appearance with proper color when tested in accordance with ASTM D4176-82.

2. By verifying within 31 days of obtaining the sample that the other properties specified in Table 1 of ASTM D975-81 are met when tested in accordance with ASTM D975-81 except that the analysis for sulfur may be performed in accordance with ASTM D1552-79 or ASTM D2622-82.

d. By obtaining a sample, at least once every 31 days of fuel oil from the storage tanks in accordance with ASTM D2276-78, and verifying within 1 week after obtaining the sample that the total particulate contamination is less than 10 mg/liter when checked in accordance with ASTM D2276-78, Method A.

e. At least once per 18 months, during shutdown, by: (A.7)

(2.4) (LD.1)

1. Subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for this class of standby service. (LA.4)

SR 3.8.1.9 2. Verifying the diesel generator capability to reject a load of greater than or equal to 3377 kW for DG-1, greater than or equal to 1377 kW for DG-2, and greater than or equal to its associated single largest post-accident load (LA.5)

add proposed Note 2 (M.6)

(B)

SURVEILLANCE REQUIREMENTS (Continued)

SR 3.8.1.19

2) Verifying the diesel generator starts on the auto-start signal, energizes the emergency busses with permanently connected loads within 15 seconds, energizes the auto-connected loads through the load sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After energization, the steady state voltage and frequency of the emergency busses shall be maintained at 4160 ± 420 volts and 60 ± 3.0 Hz during this test.

b) For division 3:

1) Verifying deenergization of the emergency bus.

2) Verifying the diesel generator starts on the auto-start signal, energizes the emergency bus with the permanently connected loads and the auto-connected emergency loads within 30 seconds and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After energization, the steady state voltage and frequency of the emergency bus shall be maintained at 4160 ± 420 volts and 60 ± 3.0 Hz during this test.

SR 3.8.1.13 7. Verifying that all automatic diesel generator division 1, 2, and 3 trips are automatically bypassed upon an ECCS actuation signal except engine overspeed, generator differential current, incomplete starting sequence and emergency manual stop.

SR 3.8.1.14 8. Verifying the diesel generator operates for at least 24 hours. During the first 2 hours of this test, the diesel generator shall be loaded to greater than or equal to 4650 kW for DG-1 and DG-2 and 2850 kW for DG-3. During the remaining 22 hours of this test, the diesel generator shall be loaded to 4400 kW for DG-1 and DG-2 and 2600 kW for DG-3. The generator voltage and frequency shall be 4160 (+420, -250) volts for DG-1 and DG-2, 4160 ± 420 volts for DG-3 and 60 ± 3.0 Hz within 10 seconds for DG-1 and DG-2 and 13 seconds for DG-3 after the start signal; the steady-state generator voltage and frequency shall be maintained within 4160 ± 420 volts and the above frequency limit during this test.

SR 3.8.1.15 Within 5 minutes after completing this 24-hour test, perform Surveillance Requirement 4.8.1.1.2.e.4.a)2) and b)2).*

*If Surveillance Requirements 4.8.1.1.2.e.4.a)2) and/or b)2) are not satisfactorily completed, it is not necessary to repeat the preceding 24-hour test. Instead, the diesel generator may be operated at 4400 kW for DG-1 or DG-2 or 2600 kW for DG-3 for 1 hour or until operating temperature has stabilized.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

M.5 Two Notes have been added to current Surveillance 4.8.1.1.2.a.5 (proposed SR 3.8.1.3). Note 3 precludes this Surveillance from being performed on more than one DG at a time. Note 4 requires that this SR be immediately preceded by a successful performance of SR 3.8.1.2 or SR 3.8.1.7 (the DG start Surveillances). While these Notes clearly represent current WNP-2 practice, they are more restrictive than current TS since the SR could currently be performed without these restrictions.

M.6 Limitations on the operating power factor are added to the single load rejection test (as Note 2 to SR 3.8.1.9), full load rejection test (SR 3.8.1.10, including Note 2), and to the 24-hour run Surveillance (SR 3.8.1.14, including Note 3). These limitations ensure the DG is conservatively tested at as close to accident conditions as reasonable, provided the power factor can be attained. The actual power factor value has been added to the Bases. A Note has been also added to SR 3.8.1.14 to ensure a momentary transient that results in the power factor not being met does not invalidate the 24 hour run. 1B

M.7 A new requirement has been added for the Division 3 loss of offsite power test (proposed SR 3.8.1.11). This requirement ensures that the autoconnected loads (e.g., the HPCS service water pump) are energized. A new requirement has also been added for the Division 3 loss of offsite power coincident with a LOCA test (proposed SR 3.8.1.19). This requirement ensures the DG is started and energizes the permanently connected loads within 15 seconds, consistent with the time provided in the ECCS initiation test (proposed SR 3.8.1.12). These are additional restrictions on plant operation.

M.8 The Divisions 1 and 2 steady state lower voltage limit when the DG is not tied to its respective bus (current Specification 4.8.1.1.2.e.5 and proposed SR 3.8.1.12) has been changed from -420 V to -250 V. The new value is consistent with the breaker closure permissive voltage. This change is an additional restriction on plant operation.

M.9 Two new requirements have been added. SR 3.8.1.12.d and SR 3.8.1.12.e ensure that permanently connected loads remain energized from the offsite power system and that emergency loads are autoconnected to the offsite power system. This is required since separate load timers are used to autoconnect some of the emergency loads to the offsite power system. This is an additional restriction on plant operation.

M.10 As with all other DG start requirements, proposed SR 3.8.1.20 is proposed to add the acceptance criteria for voltage limits (lower only). These acceptance criteria are consistent with all other DG start acceptance criteria. This is an added restriction on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.3 (cont'd) Technical Specifications. Procedural controls on DG standby alignment, and the definition of OPERABILITY are sufficient to ensure the DG remains aligned to provide standby power. Removal of this Surveillance from the Technical Specifications will have no effect on DG OPERABILITY. Changes to the relocated requirements in procedures will be controlled by the provisions of 10 CFR 50.59.

LA.4 The requirement to inspect the DGs in accordance with procedures prepared in accordance with manufacturer's recommendations is proposed to be relocated to plant procedures. This inspection is a preventative maintenance type requirement. The failure to perform this requirement does not necessarily result in an inoperable DG. This requirement is oriented toward long term DG OPERABILITY and does not have an immediate impact on DG OPERABILITY. DG OPERABILITY is verified by the SRs maintained in Specification 3.8.1. In addition, procedural controls on DG inspections recommended by the manufacturer are sufficient to ensure the DG receives the necessary inspections. As a result, this requirement is not necessary to include in the Technical Specifications. Changes to the relocated requirements in procedures will be controlled by the provisions of 10 CFR 50.59. 1 (B)

LA.5 The specific kilowatt value of the single largest post-accident load for the single load rejection Surveillance Requirement is proposed to be relocated. The reference to the single largest post-accident load within the Technical Specifications is not necessary to adequately present the requirement. The value of the load, as well as the component itself, are specifically detailed in the Bases. This detail is not necessary to ensure the OPERABILITY of the diesel generators. The requirements of Specification 3.8.1 and the associated Surveillance Requirements (including SR 3.8.1.9) for the diesel generators are adequate to ensure the diesel generators are maintained OPERABLE. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

Similarly, the load value for the autoconnected loads is proposed to be relocated to the FSAR. The specific load value for the autoconnected loads on the diesel generators is a design detail. This detail is not necessary to ensure the OPERABILITY of the diesel generators. The definition of OPERABILITY, the requirements of Specification 3.8.1, and the associated Surveillance Requirements for the diesel generators are adequate to ensure the diesel generators are maintained OPERABLE. Changes to the FSAR are controlled by 10 CFR 50.59. In addition, Any change to the loads placed on the DG will be controlled by 10 CFR 50.59 (a design change is required to change the actual loads).

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.19 The current Specification 4.8.1.1.3 that all DG failures be reported to the NRC in a special report pursuant to current Specification 6.9.1 is proposed to be removed. This requirement is proposed to be removed from Technical Specifications in accordance with the guidance of Generic Letter 94-01. GL 94-01 allows DG failure reporting requirements to be removed, but licensees must continue to comply with reporting requirements of 10 CFR 50.72 and 50.73, which may require notifying and reporting DG failures to the NRC. Also, this change does not impact the safe operation of the plant because the report is submitted after the DG failure has occurred and does not require NRC approval. Therefore, this requirement is being removed from the Technical Specifications consistent with the guidance of GL 94-01.

L.20 Current Surveillance Requirements 4.8.1.1.2.a.4, 4.8.1.1.2.e.4, 4.8.1.1.2.e.5, 4.8.1.1.2.e.6, and 4.8.1.1.2.f (proposed SRs 3.8.1.7, 3.8.1.11.c.1, 3.8.1.12.a & b, 3.8.1.15.a & b, 3.8.1.19.c.1, and 3.8.1.20) have been changed to update the diesel generator (DG) start times. The proposed changes increase the start times for the Division 1 DG (DG-1) and the Division 2 DG (DG-2) to rated voltage and frequency, or to load connection, from 10 seconds to 15 seconds. The proposed changes increase the start time for the Division 3 DG (DG-3) from 13 to 15 seconds for other than a loss of offsite power start signal by itself. For a loss of offsite power start signal by itself, the proposed changes increase the DG-3 start time from 13 to 18 seconds. These changes are based on the relaxed response times assumed for Emergency Core Cooling System (ECCS) parameters in the 10 CFR 50.46 and 10 CFR 50, Appendix K analyses (SAFER/GESTR-LOCA analysis) performed in support of the WNP-2 power uprate approved by the NRC in an Amendment dated May 2, 1995. This analysis, NEDC-32115P, Revision 2, assumes the following ECCS response times (as shown in Table 4-3 of the analysis):

a. HPCS - 37 seconds (15 seconds DG start time, 19 seconds valve stroke time, and 3 seconds instrument response time);

b. LPCS - 42 seconds (15 seconds DG start time, 24 seconds valve stroke time, and 3 seconds instrument response time); and

c. LPCI - 46 seconds (15 seconds DG start time, 28 seconds valve stroke time, and 3 seconds instrument response time).

The DG start times were established to demonstrate DG OPERABILITY and identify equipment degradation and to provide assurance that ECCS equipment will function to maintain parameters within the Licensing Basis fuel peak cladding temperature (PCT) acceptance criteria of 10 CFR 50.46 and Appendix K for a large break loss of coolant accident (LOCA) coincident with a loss of offsite power. Standard Technical Specifications for BWR/5 plants (NUREG-0123, Revision 3) allow 10 seconds for DG start and acceleration to

TECHNICAL CHANGES - LESS RESTRICTIVE

L.20 (cont'd) rated speed and 13 seconds to attain rated voltage and frequency. Currently, WNP-2 Technical Specifications require DG-1 and DG-2 to start and attain rated voltage and frequency within 10 seconds after a start signal. On a loss of offsite power, DG-1 and DG-2 are required to start and energize their emergency busses and permanently connected loads within 10 seconds after receipt of an undervoltage auto-start signal. For DG-3, the Technical Specifications currently require the DG to start and attain rated voltage and frequency within 13 seconds after a start signal. On a loss of offsite power, DG-3 is required to start and energize its emergency bus and permanently connected loads within 13 seconds after receipt of an undervoltage auto-start signal. The loss of offsite power start logic for DG-3 includes an additional 3 second time delay prior to initiation of the DG breaker close signal, which accounts for the difference between the required start times for DG-1 and DG-2 (10 seconds), and DG-3 (13 seconds). The 3 second time delay for DG-3 is automatically bypassed on an ECCS initiation start signal. Thus, for LOCA conditions and ECCS considerations, the start time for all three DGs is the same (i.e., 10 seconds). The original 10 CFR 50.46 and Appendix K analyses for WNP-2 assumed a 10 second DG start and load time for all three DGs. It is proposed that the start times for all three DGs be increased from 10 to 15 seconds on an ECCS initiation start signal and the start and loading times for an ECCS initiation start signal in conjunction with a loss of offsite power start signal also be increased from 10 to 15 seconds based on the results of the NRC approved SAFER/GESTR-LOCA analysis. For DG-3, it is proposed that the start and load time be increased from 13 to 18 seconds on a loss of offsite power start signal by itself to account for the additional 3 second time delay for this unique condition.

Historically, the analysis of the large break LOCA had been performed on a very conservative basis with margin added at every step of the calculation. This was done partly as a result of the restrictions imposed by the requirements of 10 CFR 50.46 and Appendix K, and partly to compensate for uncertainties inherent in the simplified models. After years of research with large-scale experiments and the development of the best estimate codes, the improved and more realistic SAFER/GESTR-LOCA licensing models for BWR plants have been approved by the NRC. These new models calculate more realistic (yet conservative) PCTs and provide the basis for relief from unnecessary plant operating and licensing restrictions. The more realistic analyses predict actual plant responses during postulated accidents to establish more appropriate operator actions and equipment performance requirements. The current LOCA analysis for WNP-2 uses these models and this licensing methodology. The analysis assumes 15 second start and load times for all three DGs, consistent with the proposed times for ECCS initiation coincident with a loss of offsite power, to demonstrate conformance with the ECCS acceptance criteria of 10 CFR 50.46 and Appendix K. The Licensing Basis PCT

TECHNICAL CHANGES - LESS RESTRICTIVE

L.20 (cont'd) for WNP-2 is currently 1440° F based on the analysis, which is well below the PCT limit of 2200° F. Therefore, WNP-2 meets the NRC licensing requirements for the SAFER/GESTR-LOCA analysis with 15 second DG start and load times.

Accident radiological dose calculations were performed to meet the recommendations of Regulatory Guide 1.3, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Boiling Water Reactors." This guide requires an assumption that a certain percentage of the radiological material available in the fuel be immediately available for leakage from containment. To release such a fraction would require the fuel PCT to exceed the 10 CFR 50.46 limit of 2200° F for a significant period of time. The SAFER/GESTR-LOCA analysis for WNP-2 demonstrated that the PCT would be limited to 1440° F. Thus, the NRC assumption for the radiological calculations is non-mechanistic and very conservative. Since the proposed changes in the DG start times do not change the inventory of material or source term available for release per this assumption, there will be no impact on the consequences of the postulated LOCA, the dose calculations, or margins to the 10 CFR 100 guidelines.

The proposed relaxation of the DG start times are the result of a change in the plant design basis. Since the DG start and loading times assumed in the current NRC approved design basis SAFER/GESTR-LOCA analysis are unchanged, there will be no affect the capability of the DGs to support equipment required to mitigate the consequences of the design basis event (i.e., a large break LOCA coincident with a loss of offsite power). Furthermore, the proposed changes will not reduce the effectiveness of the Surveillance Requirements to demonstrate DG operability, detect equipment degradation, or assure reliability since the Surveillance Requirements continue to satisfy the recommendations of Regulatory Guide 1.9, "Selection of Diesel Generator Set Capacity for Standby Power Supplies," March 10, 1971, and Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," Revision 1, August 1977, which are the bases for the current Surveillance Requirements. Moreover, the proposed changes will not affect current commitments related to DG reliability and the Maintenance Rule which are designed to identify and correct equipment deficiencies and degradation to maintain DG operability and reliability.

ELECTRICAL POWER SYSTEMS

SURVEILLANCE REQUIREMENTS

4.8.2.1 Each of the above required 250-volt, 125-volt, ~~and ±24-volt~~ batteries and chargers shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that:

1. The parameters in Table 4.8.2.1-1 meet the Category A limits, and

2. Total battery terminal voltage on float charge is greater than or equal to ~~25.8 volts~~, 129 volts, and 258 volts for the ~~±24-volt~~, 125-volt, and 250-volt batteries, respectively. (SR 3.8.4.1)

b. At least once per 92 days and within 7 days after a battery discharge with battery terminal voltage below ~~22 volts~~, 110 volts, and 220 volts for the ~~±24-volt~~, 125-volt, and 250-volt batteries, respectively, or battery overcharge with battery terminal voltage above ~~31 volts~~, 150 volts, and 300 volts for the ~~±24-volt~~, 125-volt, and 250-volt batteries, respectively, by verifying that:

1. The parameters in Table 4.8.2.1-1 meet the Category B limits,

2. There is no visible corrosion at either terminals or connectors, or the connection resistance of these items is less than 250 x 10^{-6} ohm, and (SR 3.8.4.2)

3. The average electrolyte temperature of 4, 10, or 20, as applicable, of connected cells for the ~~24-~~, 125- and 250-volt batteries is above 60°F.

c. At least once per ~~18~~ 12 months by verifying that:

1. The cells, cell plates, and battery racks show no visual indication of physical damage or abnormal deterioration, (SR 3.8.4.3)

2. The cell-to-cell and terminal connections are clean, tight, free of corrosion and coated with anti-corrosion material, (SR 3.8.4.4)

3. The resistance of each cell-to-cell and terminal connection is less than or equal to 250 x 10^{-6} ohms, and (SR 3.8.4.5)

4. The battery charger will supply: every 24 months

1. For ~~±24-volt~~ batteries at least 25 amperes at a ~~minimum of~~ 25.8 volts for at least 4 hours.

2. For the 125-volt batteries, at least ~~200~~ amperes at a minimum of 129 volts for at least 4 hours for Divisions 1 and 2 and at least ~~50~~ amperes at a minimum of 129 volts for at least ~~4~~ 1.5 hours for Division 3. (SR 3.8.4.6)

3. For the 250-volt battery, at least ~~400~~ amperes at a minimum of ~~258~~ 252 volts for at least 4 hours. 1.5

the required load

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ELECTRICAL POWER SYSTEMS

SURVEILLANCE REQUIREMENTS (Continued)

d. At least once per 18 months, during shutdown, by verifying that either:

1. The battery capacity is adequate to supply and maintain in OPERABLE status ~~all of the actual emergency loads~~ for ~~2 hours~~ for Divisions 1, 2 and 3 when the battery is subjected to a battery service test, or

SR 3.8.4.7

2. The battery capacity is adequate to supply a dummy load (minimum amperage) based on anticipated loads required during loss of offsite power (LOOP) and loss-of-coolant accident (LOCA) conditions, while maintaining the battery terminal voltage greater than or equal to ~~21 volts for the 24 volt battery~~ 105 volts for the 125-volt battery, and 210 volts for the 250-volt battery, and 105 volts for the 125-volt Div. 3 battery.

SR 3.8.4.8

e. At least once per 60 months during shutdown by verifying that the battery capacity is at least 80% (83.4% for the 250 Volt battery) of the manufacturer's rating when subjected to a performance discharge test or a modified performance discharge test. At this once per 60-month interval, this performance discharge test may be performed in lieu of the battery service test.

NOTE 1 TO SR 3.8.4.7

SR 3.8.4.8

f. At least once per 18 months during shutdown performance discharge tests of battery capacity shall be given to any battery that shows signs of degradation or has reached 85% of the service life expected for the application. Degradation is indicated when the battery capacity drops more than 10% of rated capacity from its average on previous performance tests, or is below 90% (93.4% for the 250 Volt battery) of the manufacturer's rating.

Add proposed Note to SR 3.8.4.8

Add Proposed NOTE 2 to SR 3.8.4.7

with capacity < 100% of manufacturer's rating.

Proposed 3rd Frequency

L.1 L.2 L.3 L.4 L.5 L.6 L.7 L.8 L.9

A.1 A.2 A.3 A.4 A.5 A.6 A.7 A.8

M.1 M.2

DISCUSSION OF CHANGES
ITS: 3.8.4 - DC SOURCES - OPERATING

ADMINISTRATIVE

A.1 The proposed Technical Specifications present the battery cell parameter limits in a separate LCO (proposed LCO 3.8.6). The hardware components (battery and charger) remain in a DC sources LCO (proposed LCO 3.8.4). This is in accordance with the format of the BWR Standard Technical Specifications, NUREG-1434. Any technical changes to these requirements are addressed in the Discussion of Changes for ITS: 3.8.6.

A.2 The format of the proposed Technical Specifications does not include providing "cross references." LCO 3.5.1 adequately prescribes the Required Actions for an inoperable ECCS without such references. Therefore, the existing reference to Specification 3.5.1 serves no functional purpose, and its removal is purely an administrative difference in presentation.

A.3 The existing limitation on 18-month Surveillances to perform them "during shutdown" is more specifically presented in the proposed Surveillances. Each proposed SR contains a specific Note limiting the performance in certain MODES. While these limitations vary from SR to SR, each is consistent with the BWR Standard Technical Specifications, NUREG-1434 presentation (or bracketed option allowed based on plant specific justification) presentation which defines the intent of "during shutdown" for each SR.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 The 18 month Frequency for current Surveillances 4.8.2.1.c.1, 4.8.2.1.c.2, 4.8.2.1.c.3, and 4.8.2.1.f is being changed to 12 months, consistent with the recommendations of IEEE-450. This is an additional restriction on plant operations. (B)

M.2 The resistance limit of CTS 4.8.2.1.b.2 and 4.8.2.1.c.3 (250×10^{-6} ohms) have been decreased for all types of connections. The new limits are $\leq$ 24.4 E-6 ohms for inter-cell connectors of the Division 1 and 2 batteries and $\leq$ 169 E-6 ohms for inter-cell connectors of the Division 3 battery. For inter-tier and inter-rack connectors, the limits are $\leq$ 20% above the resistance as measured during installation. This is an additional restriction on plant operation. (B)

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 LCO 3.8.4 has been written to require the Division 1, 2 and 3 DC electrical power subsystems to be OPERABLE and the details relating to system OPERABILITY (what constitutes a DC Source division) are proposed to be relocated to the Bases. The details for system OPERABILITY are not necessary in the LCO. The definition of OPERABILITY suffices. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LA.2 The requirements for the ± 24 volt batteries and associated chargers, including the Surveillance Requirements, are proposed to be relocated to the Licensee Controlled Specifications (LCS) Manual. The only Technical Specification related components powered by these batteries and chargers are the intermediate range monitor (IRM) and the source range monitor (SRM) instrumentation. They are a support system for the IRM and SRM instrumentation. As such, the requirements for the ± 24 volt batteries and associated chargers are adequately addressed by the definition of OPERABILITY. These instruments are not assumed to function during a design basis Loss of Offsite Power accident. Upon a loss of offsite power, the reactor will scram (due to loss of power to the scram solenoids) and all control rods will insert. Therefore, the IRMs are not needed to provide an RPS scram. Once the control rods are inserted, the reactor is subcritical, thus the SRMs are not needed to monitor core condition; the reactor cannot inadvertently restart since a control rod block will be inserted with the reactor mode switch is in the shutdown position. Therefore, the ± 24 volt batteries have no safety function once offsite power is lost. The SRMs and IRMs do not actually need power supplied by a battery that continues to provide power after a loss of offsite power accident; their power supply could have been designed to be from an AC to DC inverter with AC power from the 480 VAC ESF buses. Changes to the LCS Manual will be controlled by the provisions of 10 CFR 50.59. (B) (B)

LA.3 Not used. (B)

LA.4 The load descriptions for the battery charger test (current Specification 4.8.2.1.c.4) are proposed to be relocated to the Bases. The battery charger vendors recommend a load test that step loads the battery chargers at three distinct loads, not just a test at the 100% rating. This loading profile is proposed to be relocated to a plant controlled document similar to the manner in which the load profile of the batteries was allowed to be relocated to the Bases. These details are not necessary to ensure the OPERABILITY of the battery chargers. The requirements of Specification 3.8.4 and SR 3.8.4.6 are adequate to ensure the battery chargers are maintained OPERABLE. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

LA.5 The requirement to perform the service test (SR 3.8.4.7) implies the need to power the emergency loads. The requirement for performance of the "service test" is also adequate to convey that the test duration must be consistent with the plant specific licensed service duration. As a result, the details of the DC loads and the licensed service duration are proposed to be relocated to the FSAR. Changes to the FSAR are controlled by the provisions of 10 CFR 50.59.

LA.6 The format of the proposed Technical Specifications does not include specific limits on degradation in the conditional frequency for SR 3.8.4.8. This information is proposed to be relocated to the Bases where it provides guidance regarding the intent of the term "degradation" as used in this Frequency. As such, this information is not necessary for performance of SR 3.8.4.8. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LD.1 The Frequencies for performing current Surveillances 4.8.2.1.c.4 and 4.8.2.1.d.1 (proposed SRs 3.8.4.6 and 3.8.4.7) have been extended from 18 months to 24 months to facilitate a change to the WNP-2 maintenance cycle from 12 months to 24 months. The current conditions in the northwest require that WNP-2 shut down each spring for an annual maintenance and refueling outage. Currently, most of the current Surveillances that are required to be performed on an 18 month interval are performed annually because they must be performed while the plant is shut down. This has resulted in increased testing, with a resultant increase in cost and personnel exposure, with no comparable increase in reliability or safety. This change is being proposed to support limiting the amount of surveillance testing that must be performed each maintenance and refueling outage. The proposed change will allow these Surveillances to extend their Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in current Specification 4.0.2 and proposed Specification 3.0.2). This proposed change was evaluated in accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991. Reviews of historical maintenance and surveillance data have shown that these tests normally pass their Surveillances at the current Frequency. An evaluation has been performed using

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd) performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) do not invalidate any assumptions in the plant licensing basis.

"Specific"

L.1 Proposed ACTION C has been added to provide clear direction as to what actions to take when the Division 1 250 V DC electrical power subsystem is inoperable. This battery and charger provide power to various reactor core isolation cooling system, residual heat removal and reactor water cleanup system valves, and to non-TS equipment such as plant controls, instrumentation, computer and communication equipment through a solid state inverter. Therefore, the 250 V DC electrical power subsystem is a support system for only three TS related functions. As such, the requirement to immediately declare the associated supported features inoperable is appropriate and consistent with the WNP-2 design. Due to this change, current ACTION a. (proposed ACTION A) has also been modified to only be applicable to the Division 1 and Division 2 125 V batteries.

L.2 Battery terminal voltage requirements have been lowered from 258 V to 252 V, and 129 V to 126 V for the 250 volt and 125 volt batteries, respectively. This change is consistent with the design of the batteries which utilize 116 cells and 58 cells, respectively, and the manufacturer's technical manuals recommendations of 2.17 volts per cell. The previous value was based on 120 cells and 60 cells, respectively and a 2.15 volts per cell requirement. Therefore, in actuality, the volts per cell requirement has increased.

L.3 The requirement of current Surveillance 4.8.2.1.b to verify that there is no visible corrosion at either terminals or connectors, or that connection resistance is less than 250 x 10E-6 ohm within 7 days after a battery discharge or overcharge, has been removed. This is consistent with the nature of the condition being verified, i.e., that the battery resistance has not degraded significantly, since corrosion rates and connection resistance are not immediately and significantly effected by a severe discharge or overcharge condition.

L.4 Requiring the connections to be "tight" results in a requirement to torque the connecting bolts. This application of a torque to confirm tightness results in unnecessary stress being applied to the bolted connection. If the connection satisfies the resistance requirements of proposed SR 3.8.4.5 (performed at the same Frequency), it can be assumed to be sufficiently torqued. The "clean" requirement has been deleted since it is redundant to the "free of corrosion" requirement.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.5 The test duration for the battery charger load test has been changed from 4 hours to 1.5 hours. The battery vendor recommends that the battery charger be tested at three discrete current outputs (loads), each of 30 minutes duration. This would provide a better indication of battery charger voltage regulation capability, since it would be tested under varying loads, instead of at a single load (which it is currently being tested). The final load would be at the 100% load rating. The vendor also provided information that the new time is adequate to determine charger OPERABILITY, and any problems normally detected in the current 4 hour test should be detected in the new 1.5 hour time. The vendor also stated that the 30 minute duration at each discrete load is sufficient time for the battery charger temperature to stabilize between the load changes (approximately 15 minutes is necessary for temperature stabilization). (B) (B)

L.6 The Notes associated with SR 3.8.4.7 and SR 3.8.4.8 have been modified to allow credit to be taken for unplanned events that satisfy the requirements of the associated SR. These notes are required to clarify that should circumstances occur during operation which result in an unplanned event which results in performance of the SR requirements, credit may be taken for the SR. This change is consistent with the BWR Standard Technical Specifications, NUREG-1434.

L.7 An allowance to perform a modified performance discharge test in lieu of a performance discharge test has been added to this Surveillance. The modified performance discharge test is a simulated duty cycle consisting of just two rates: One 1 minute rate published for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test. Since the ampere-hours removed by a rated 1 minute discharge represent a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test.

L.8 A Note has been added to proposed SR 3.8.4.7, to allow the 60 month performance discharge test to be performed in lieu of the service test of SR 3.8.4.7. As stated in the BWR Standard Technical Specifications Bases, NUREG-1434, this substitution is acceptable, because SR 3.8.4.8 represents a more severe test of battery capacity than SR 3.8.4.7.

L.9 A battery can show degradation prior to expiration of expected life, and still be within the required capacity to meet OPERABILITY requirements. In this event, a Frequency less restrictive than the 18 month Frequency is justified. The 24 month Frequency is consistent with the BWR STS, NUREG-1434. The SR will now be required to be performed every 18 months when a

TECHNICAL CHANGES - LESS RESTRICTIVE

L.9 (cont'd) battery shows degradation or has reached 85% of expected life with capacity < 100% of manufacturer's rating and every 24 months when a battery has reached 85% of expected life with capacity ≥ 100% of manufacturer's rating.

DISCUSSION OF CHANGES
ITS: 3.8.5 - DC SOURCES—SHUTDOWN

ADMINISTRATIVE

A.1 The proposed Technical Specifications present the station service battery hardware components (battery and charger) in the DC Sources LCO (proposed LCO 3.8.5). The battery cell parameters are in a separate LCO (proposed LCO 3.8.6). (B)

A.2 The format of the proposed Technical Specifications does not include providing "cross references." LCOs 3.5.2 and 3.5.3 adequately prescribe the Required Actions for an inoperable ECCS without such references. Therefore the existing reference to Specifications 3.5.2 and 3.5.3 provide no functional purpose, and its removal is purely an administrative difference in presentation.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 The existing requirement for "Division 1 or Division 2" DC sources to be OPERABLE during shutdown conditions is not specific as to what that single source must be powering. The proposed requirement specifies that the sources necessary to supply DC power to all equipment required to be OPERABLE in the current plant condition must be OPERABLE. This added restriction conservatively assures the needed sources of power are OPERABLE, even if this results in both the Division 1 and Division 2 sources being required. The ACTION has been subsequently modified to be "one or more" instead of the current "one," to account for this potential addition.

Since the proposed DC source OPERABILITY requirements require supplying power to all necessary loads, if one or more required DC loads are not being supplied the required DC power, the DC source is inoperable. In this event it may not be necessary to suspend all CORE ALTERATIONS, irradiated fuel handling, and OPDRVs. Conservative actions can be assured if all required equipment without the necessary DC power is declared inoperable and the associated ACTIONS taken.

Therefore, along with the conservative additional requirements placed on the Division 1 and Division 2 DC system, Required Action A.1 is also proposed. These additions represent restrictions consistent with implicit assumptions for operation in shutdown conditions (required equipment receiving the necessary required power)--restrictions which are not currently imposed via the Technical Specifications.

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.1 (cont'd) addressed in Specification 3.8.7, "Distribution Systems—Operating." In addition, more buses than are currently listed are now required (as identified in the Bases). Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

LA.2 The requirements for the ± 24 volt power panels are proposed to be relocated to plant procedures. These power panels provide power to the intermediate range monitor (IRM) and the source range monitor (SRM) instrumentation. They are a support system for the IRM and SRM instrumentation. As such, the requirements for the ± 24 volt power panels are adequately addressed by the definition of OPERABILITY. Changes to the relocated requirements in procedures will be controlled by the provisions of 10 CFR 50.59.

LA.3 Details of the methods for performing the Surveillance (on the busses/MCCs/panels) to verify the required Distribution Systems are OPERABLE are proposed to be relocated to the Bases. These details are not necessary to ensure the OPERABILITY of the Distribution Systems. The requirements of Specification 3.8.7 and SR 3.8.7.1 are adequate to ensure the required Distribution Systems are maintained OPERABLE. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

"Specific"

L.1 Proposed ACTION D has been added to provide clear direction as to what actions to take when the Division 1 250 V DC electrical power distribution subsystem is inoperable. This distribution subsystem provides power to various reactor core isolation cooling system, residual heat removal and reactor water cleanup system valves, and to non-TS equipment such as plant controls, instrumentation, computer and communication equipment through a solid state inverter. Therefore, the 250 V DC electrical power distribution subsystem is a support system for only three TS related functions. As such, the requirement to immediately declare the associated supported features inoperable is appropriate and consistent with the WNP-2 design. Due to this change, the current ACTION (proposed ACTION B) has been modified to only be applicable to the Division 1 and 2 125 V DC electrical power distribution subsystems.

L.2 The Surveillance has been modified to remove the requirement to verify the subsystem voltages to require only power availability indication. This change is required because voltage indication is not available on all AC or DC buses. The Surveillance will still ensure proper power availability to the AC and DC buses (i.e., the buses are energized). Proper power availability is currently

TECHNICAL CHANGES - LESS RESTRICTIVE

L.2 (cont'd) performed by verifying a load powered from the bus is operating. In addition, another acceptable method which can be employed is to verify the absence of a low voltage alarm on the respective bus. (B)

TECHNICAL CHANGES - MORE RESTRICTIVE

M.2 (cont'd) to commence and continue attempts to restore the necessary distribution systems is proposed. (Note that if actions are taken in accordance with the proposed Required Action A.1, sufficiently conservative measures are assured by the ACTIONS for the individual components declared inoperable without requiring the efforts to restore the inoperable source.)

The proposed Required Action A.2.4 results in an action which does not allow continued operation in the existing plant condition. This has the effect of not allowing MODE changes per LCO 3.0.4. Therefore this existing explicit requirement is implicitly addressed in the proposed ACTIONS.

An additional Required Action (Required Action A.2.5) related to proposed LCO 3.0.6 is also proposed. This Required Action allows the ACTIONS for inoperable distribution systems to be taken, and thereby not take ACTIONS for each inoperable supported component. This Required Action assures the appropriate consideration is applied for shutdown cooling systems that are without required power.

M.3 In lieu of declaring the HPCS System inoperable and taking the ACTIONS of the appropriate LCO, new Required Actions have been provided for when the Division 3 AC or DC distribution subsystem is inoperable, consistent with the Required Actions for inoperable Division 1 and Division 2 AC and DC distribution subsystems. The Required Actions (A.2.1, A.2.2, and A.2.3) require suspension of CORE ALTERATIONS, movement of irradiated fuel assemblies in the secondary containment, and OPDRVs. These Required Actions are more restrictive than currently required, since the current TS only requires OPDRVs to be suspended (and it allows 4 hours to start this action). 1B 1B

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The details relating to system design and OPERABILITY are proposed to be relocated to the Bases. The details for system OPERABILITY are not necessary in the LCO. The definition of OPERABILITY suffices. The design details are not necessary to be included in the Technical Specifications to ensure the OPERABILITY of the Distribution Systems since OPERABILITY requirements are adequately addressed in Specification 3.8.8, "Distribution Systems–Shutdown." Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

LA.2 Details of the methods for performing the Surveillance (on the buses/MCCs/panels) to verify the required Distribution Systems are OPERABLE are proposed to be relocated to the Bases. These details are not necessary to ensure the OPERABILITY of the Distribution Systems. The requirements of Specification 3.8.8 and SR 3.8.8.1 are adequate to ensure the required Distribution Systems are maintained OPERABLE. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

"Specific"

L.1 The Surveillance has been modified to remove the requirement to verify the subsystem voltages to require only power availability indication. This change is required because voltage indication is not available on all AC or DC buses. The Surveillance will still ensure proper power availability to the AC and DC buses (i.e., the buses are energized). Proper power availability is currently performed by verifying a load powered from the bus is operating. In addition, another acceptable method which can be employed is to verify the absence of a low voltage alarm on the respective bus. (B)

ADMINISTRATIVE (continued)

A.7 This footnote is an explicit part of the definition of MODE 5, as defined in current Table 1.2 and proposed Table 1.1-1. Therefore, the footnote has been deleted from this Specification.

A.8 The allowance to place the reactor mode switch in the Run or Startup/Hot Standby position while in MODE 5 has been moved to Specification 3.10.2 in accordance with the BWR Standard Technical Specifications, NUREG-1434. Any technical changes to the requirements will be addressed in the Discussion of Changes for ITS 3.10.2.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

None

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

None

"Specific"

L.1 The normal periodic surveillance frequency for the component tests provides adequate assurance of OPERABILITY. As such, the requirement to perform the Surveillance Requirement "within 24 hours prior to the start of" use of the component has been deleted. If the Surveillance has not been performed within the specified interval, use of the component is not allowed since proposed SR 3.0.1 (current Specification 4.0.1) requires a Surveillance be met within the specified Frequency while in the applicable MODE or condition. Proposed SR 3.0.1 (current Specification 4.0.3) also states that failure to meet the Surveillance constitutes failure to meet the LCO, which would then require the ACTIONS of the LCO to be taken. If this specific Surveillance Requirement is not performed within the specified Frequency prior to entering the applicable condition, then as soon as the applicable condition is entered, this would result in the LCO not being met. The ACTIONS for this LCO require immediate action to be taken to exit the Applicability of the LCO. Therefore, this effectively ensures that the Applicability of the (B)

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) LCO is not entered with the Surveillance not current. Additionally, plant operational experience has shown the normal periodic Surveillance Frequency to be adequate for maintaining OPERABILITY. 1(B)

L.2 Any time the OPERABILITY of a system or component has been affected by repair, maintenance, or replacement of a component, post maintenance testing is required to demonstrate OPERABILITY of the system or component. After restoration of a component that caused a required SR to be failed, SR 3.0.1 requires the appropriate SRs (in this case SR 3.9.1.1) to be performed to demonstrate the OPERABILITY of the affected components. Therefore, explicit post maintenance Surveillance Requirements are not required and have been deleted from the Technical Specifications. Entry into the applicable specified condition without performing this post maintenance testing also continues to be precluded except where allowed, as discussed in the Bases for proposed SR 3.0.1.

DISCUSSION OF CHANGES
ITS: 3.9.2 - REFUEL POSITION ONE-ROD-OUT INTERLOCK

TECHNICAL CHANGES - MORE RESTRICTIVE

None

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

None

"Specific"

L.1 Reactor mode switch OPERABILITY is included as part of the OPERABILITY of the one-rod-out interlock required by proposed LCO 3.9.2. Movement of the reactor mode switch from the Shutdown position is adequately controlled by proposed Table 1.1-1. Reactor mode switch positions other than Refuel and Shutdown result in the unit entering some other MODE; with the associated Technical Specification compliance requirements of that MODE and of proposed LCO 3.0.4. The Shutdown position is not allowed for proposed LCO 3.9.2 since a control rod cannot be withdrawn with the reactor mode switch in Shutdown. Therefore, the requirement to "lock" the mode switch in Shutdown is proposed to be deleted.

L.2 With the one-rod-out interlock inoperable, ACTIONS have been revised to immediately suspend control rod withdrawal and initiate action to insert all insertable control rods in core cells containing one or more fuel assemblies (proposed Required Actions A.1 and A.2). These Required Actions compensate for an inoperable one-rod-out interlock and provide adequate protection against potential reactivity excursions. Further, moving the mode switch to the shutdown position would cause an unnecessary pressure transient on the control rod drive system.

L.3 The normal periodic Surveillance Frequency for the component tests provides adequate assurance of OPERABILITY. As such, the requirement to perform the Surveillance Requirement "within 2 hours prior to" or "within 24 hours prior to the start of" use of the component has been deleted. If the Surveillance has not been performed within the specified interval, use of the component is not allowed since proposed SR 3.0.1 (current Specification 4.0.1) requires a Surveillance be met within the specified Frequency while in the applicable MODE or condition. Proposed SR 3.0.1 (current Specification 4.0.3) also states that failure to meet the Surveillance constitutes failure to meet the LCO, which would then require the ACTIONS of the LCO to be taken. If this specific Surveillance Requirement is not performed within the specified Frequency prior to entering the applicable MODE and condition, then as soon as the applicable MODE and condition are

TECHNICAL CHANGES - LESS RESTRICTIVE

L.3 (cont'd) entered, this would result in the LCO not being met. The ACTIONS for this LCO require immediate action to be taken to exit the Applicability of the LCO. Therefore, this effectively ensures that the Applicability of the LCO is not entered with the Surveillance not current. Additionally, plant operational experience has shown the normal periodic Surveillance Frequency to be adequate for maintaining OPERABILITY. (B)

L.4 To properly perform a test of the one-rod-out interlock, a control rod must be withdrawn. However, current Specification 4.0.1 (proposed SR 3.0.1) requires a Surveillance to be met within the specified Frequency while in the applicable MODE or condition. This essentially ensures that the Applicability of the LCO is not entered with the Surveillance not current. (If this specific Surveillance Requirement is not performed within the specified Frequency prior to entering the applicable MODE and condition, then as soon as the applicable MODE and condition are entered, this would result in the LCO not being met. The ACTIONS for this LCO require immediate action to be taken to exit the Applicability of the LCO.) Therefore, an allowance is provided to enter the LCOs Applicability for a short time (1 hour) to provide adequate time to perform the required Surveillance. The 1 hour Frequency is considered adequate because of the procedural controls on control rod withdrawals and indications available in the control room to alert the operator of control rods not fully inserted. (B)

L.5 Any time the OPERABILITY of a system or component has been affected by repair, maintenance, or replacement of a component, post maintenance testing is required to demonstrate OPERABILITY of the system or component. After restoration of a component that caused a required SR to be failed, SR 3.0.1 requires the appropriate SRs (in this case SR 3.9.2.2) to be performed to demonstrate the OPERABILITY of the affected components. Therefore, explicit post maintenance Surveillance Requirements are not required and have been deleted from the Technical Specifications. Entry into the applicable specified condition without performing this post maintenance testing also continues to be excluded except where allowed, as discussed in the Bases for proposed SR 3.0.1.

DISCUSSION OF CHANGES
ITS: 3.9.3 - CONTROL ROD POSITION

ADMINISTRATIVE

A.1 The format of the proposed Technical Specifications does not include providing "cross references." Proposed LCO 3.0.7 adequately prescribes the use of the Special Operations LCOs without such references. Therefore the existing references to Specifications 3.9.10.1 and 3.9.10.2, and Special Test Exception 3.10.3 serve no functional purpose, and their removal is administrative.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

None

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

None

"Specific"

L.1 The applicability of the requirement for all control rods to be fully inserted is revised to "when loading fuel assemblies into the core" consistent with the accident analysis. The control rod removal error during refueling analysis assumes all control rods are inserted only during fuel loading, not unloading or other CORE ALTERATIONS. A fuel unloading error (incorrect bundle withdrawn) cannot increase the reactivity of the core and cause an inadvertent criticality. In addition, the current ACTION excludes control rod movement. Therefore, the proposed Applicability has been specifically tied to loading fuel assemblies into the core consistent with accident analysis assumptions, the Required Actions have been revised to reflect placing the plant in a condition in which the LCO does not apply, and the Surveillance Requirement has been modified to reflect this change.

L.2 The normal periodic Surveillance Frequency for the verification provides adequate assurance of OPERABILITY. As such, the requirement to perform the Surveillance Requirement "within 2 hours prior to" use of the component has been deleted. If the Surveillance has not been performed within the specified interval, use of the component is not allowed since proposed SR 3.0.1 (current Specification 4.0.1) requires a Surveillance be met

TECHNICAL CHANGES - LESS RESTRICTIVE

L.2 (cont'd) within the specified Frequency while in the applicable MODE or condition. Proposed SR 3.0.1 (current Specification 4.0.3) also states that failure to meet the Surveillance constitutes failure to meet the LCO, which would then require the ACTIONS of the LCO to be taken. If this specific Surveillance Requirement is not performed within the specified Frequency prior to entering the applicable condition, then as soon as the applicable condition is entered, this would result in the LCO not being met. The ACTIONS for this LCO require immediate action to be taken to exit the Applicability of the LCO. Therefore, this effectively ensures that the Applicability of the LCO is not entered with the Surveillance not current. Additionally, plant operational experience has shown the normal periodic Surveillance Frequency to be adequate for maintaining OPERABILITY. (B)

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

None

"Specific"

L.1 The existing requirement for MODE 5 control rod position indication requires the position indication system to indicate the current position of the control rod. This position indication requirement is omitted in that no position indication is proposed to be required other than the full-in position indication. The OPERABILITY of the control rod "full-in" position indication for each control rod (whether the control rod is inserted or withdrawn) is proposed to be required to support OPERABILITY of the refueling interlocks (proposed LCO 3.9.1) and OPERABILITY of the one-rod-out interlock (proposed LCO 3.9.2). While the full-in position indicators appear to be required, the ACTIONS provided (if it is inoperable) do not adequately compensate for its inoperability (it only requires the position of the control rod to be known or the rod to be inserted).

Proposed LCO 3.9.4 omits the general position indication requirement and adds a specific requirement for the full-in position indication to be OPERABLE for each control rod, regardless of the actual position of the control rod. This added restriction details requirements consistent with the intent of requiring the refueling interlocks and the one-rod-out interlock to be OPERABLE. Proposed LCO 3.9.4 and LCO 3.9.5 for MODE 5 do not require the specific position of a withdrawn control rod to be indicated. The proposed requirement only requires that a withdrawn control rod <u>not</u> indicate full-in. Since only one control rod can be withdrawn while in MODE 5 (exceptions to this are addressed, in Special Operations LCOs - Section 3.10), and the position of the control rod is not a consideration in any accident or transient when in this condition, the precise position of the control rod is insignificant. The critical safety issue, whether the control rod is fully inserted or not, is addressed by the proposed LCO 3.9.4 requirement.

In addition, the Surveillance Requirements have also been modified to be consistent with this concept (the full-in indicator only must be OPERABLE). The new Surveillance (SR 3.9.4.1) requires that each time a control rod is withdrawn from the full-in position, the full-in indication is indicating correctly (i.e., it is not indicating full-in when a control rod is withdrawn). The current requirements to verify the position of the control rod every 24 hours (CTS 4.1.3.7.a), that the control rod position changes during exercise tests (CTS 4.1.3.7.b), and that the full-out indicator functions during rod coupling checks (CTS 4.1.3.7.c), have been deleted. CTS 4.1.3.7.a is not necessary

(B)

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) since, as stated above, only the "full-in" position indication is needed. The "full-in" position indication is verified by proposed SR 3.9.4.1, CTS 4.1.3.7.b has been deleted since it is not currently required in MODE 5. The Surveillance is only required when performing CTS 3.1.3.1.2, which is only required in MODES 1 and 2, not in MODE 5. CTS 4.1.3.7.c has been deleted since it is only required when performing CTS 4.1.3.6.b, and the CTS 4.1.3.6.b MODE 5 requirement was previously deleted (See Discussion of Changes comment L.9 in ITS: 3.1.3).

B

DISCUSSION OF CHANGES
ITS: 3.9.6 - RPV WATER LEVEL – IRRADIATED FUEL

ADMINISTRATIVE

A.1 The requirements for handling new fuel assemblies and control rods have been moved to Specification 3.9.7 in accordance with the BWR Standard Technical Specifications, NUREG-1434. Any technical changes to the requirements will be addressed in the Discussion of Changes for ITS: 3.9.7.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

None

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The allowance to place all fuel assemblies in a safe condition prior to suspending load movement in the event of low water level is proposed to be relocated to the Bases. This allowance is not necessary for assuring, in the case of reactor vessel water level not within limits, actions are taken to preclude a fuel handling accident from occurring. Proposed Required Action A.1 is adequate to preclude a fuel handling accident from occurring. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

"Specific"

L.1 The normal periodic Surveillance Frequency for the verification provides adequate assurance of OPERABILITY. As such, the requirement to perform the Surveillance Requirement "within 2 hours prior to the start of" handling fuel assemblies has been deleted. If the Surveillance has not been performed within the specified interval, handling fuel assemblies is not allowed since proposed SR 3.0.1 (current Specification 4.0.1) requires a Surveillance be met within the specified Frequency while in the applicable MODE or condition. Proposed SR 3.0.1 (current Specification 4.0.3) also states that failure to meet the Surveillance constitutes failure to meet the LCO, which would then require the ACTIONS of the LCO to be taken. If this specific Surveillance Requirement is not performed within the specified Frequency prior to entering the applicable condition, then as soon as the applicable condition is entered, this would result in the

B

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) LCO not being met. The ACTIONS for this LCO require immediate action to be taken to exit the Applicability of the LCO. Therefore, this effectively ensures that the Applicability of the LCO is not entered with the Surveillance not current. Additionally, plant operational experience has shown the normal periodic Surveillance Frequency to be adequate for maintaining OPERABILITY. (B)

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) level still ensures that the assumed iodine retention factors are met. In addition, the number of irradiated fuel pins that are damaged in the drop of a new fuel assembly or control rod is less than that assumed in the dropping of an irradiated fuel assembly. Thus, the amount of fission products released is less.

L.2 The normal periodic Surveillance Frequency for the verification provides adequate assurance of OPERABILITY. As such, the requirement to perform the Surveillance Requirement "within 2 hours prior to the start of" handling fuel assemblies or control rods has been deleted. If the Surveillance has not been performed within the specified interval, handling fuel assemblies or control rods is not allowed since proposed SR 3.0.1 (current Specification 4.0.1) requires a Surveillance be met within the specified Frequency while in the applicable MODE or condition. Proposed SR 3.0.1 (current Specification 4.0.3) also states that failure to meet the Surveillance constitutes failure to meet the LCO, which would then require the ACTIONS of the LCO to be taken. If this specific Surveillance Requirement is not performed within the specified Frequency prior to entering the applicable condition, then as soon as the applicable condition is entered, this would result in the LCO not being met. The ACTIONS for this LCO require immediate action to be taken to exit the Applicability of the LCO. Therefore, this effectively ensures that the Applicability of the LCO is not entered with the Surveillance not current. Additionally, plant operational experience has shown the normal periodic Surveillance Frequency to be adequate for maintaining OPERABILITY. B

DISCUSSION OF CHANGES
CTS: 3/4.9.7 - CRANE TRAVEL - SPENT FUEL STORAGE POOL

ADMINISTRATIVE

None

RELOCATED SPECIFICATIONS

R.1 The crane travel limits are provided by physical design and administrative controls, and are not process variables which are monitored and controlled by the operator; neither are they components which are part of the primary success path to mitigate a design basis accident. Therefore, the requirements specified in current Specification 3/4.9.7 do not satisfy the NRC Policy Statement Technical Specification screening criteria as documented in the Application of Selection Criteria to the WNP-2 Technical Specifications and will be relocated to plant documents controlled in accordance with 10 CFR 50.59. 1B

TECHNICAL CHANGES - MORE RESTRICTIVE

None

TECHNICAL CHANGES - LESS RESTRICTIVE

None

ADMINISTRATIVE

A.6 (cont'd) requirements, then SR 3.10.4.2 is not required to be performed (since LCO 3.10.4.2.c.1 is one option and LCO 3.10.4.2.c.2, which is verified by SR 3.10.4.2, is the other option). Since these Notes have been added for clarity, they are considered administrative changes.

A.7 The refuel position one-rod-out interlock Surveillances have been replaced with a generic Surveillance Requirement (proposed SR 3.10.4.1) to perform all required Surveillances in accordance with the applicable SRs; in this case, with the SRs of LCO 3.9.2, Refuel Position One-Rod-Out Interlock. Since this proposed LCO requires the refuel position one-rod-out interlock to be OPERABLE in accordance with proposed LCO 3.9.2, the proposed Surveillance Requirements should be those required by proposed LCO 3.9.2. The format of the BWR Standard Technical Specifications, NUREG-1434, uses a generic Surveillance Requirement (proposed SR 3.10.4.1) to specify required Surveillances of other LCOs. Any changes to these current Surveillance Requirements will be addressed in the Discussion of Changes for ITS: 3.9.2. 1B 1B

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 In the event requirements are not met and the withdrawn control rod is insertable (proposed ACTION A), two additional Required Actions are proposed. Required Action A.2.1 requires action to be initiated immediately to fully insert all insertable control rods. Required Action A.2.2 requires the placing of the reactor mode switch to the Shutdown position, which will preclude withdrawal of any control rod. These Required Actions will result in exiting the Applicability of the Special Operation LCO and return the reactor mode switch to its required position for normal MODE 4 operation. In the event requirements are not met and the withdrawn control rod is not insertable, an additional Required Action is proposed. Required Action B.2.1 requires action to be initiated immediately to fully insert all control rods. This Required Action will essentially result in exiting the Applicability of the Special Operations LCO. These proposed requirements are additional restrictions on plant operation.

M.2 A new requirement has been added to ensure the control rod position indication is OPERABLE (proposed LCO 3.10.4, second half of the b.1 requirements). The control rod position indication must be OPERABLE to support the one-rod-out interlock. This is an additional restriction on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The details of recommended procedures for disarming control rod(s) are proposed to be relocated to the Bases. These details are not necessary to ensure required control rods are disarmed. Specification 3.10.4 and SR 3.10.4.2, which require disarming of all control rods in a five by five array centered on the control rod being withdrawn, are adequate for ensuring required control rods are disarmed. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the Technical Specifications.

"Specific"

L.1 The requirement to "lock" the reactor mode switch in Shutdown or Refuel and the explicit requirement for the reactor mode switch to be OPERABLE is proposed to be deleted. Reactor mode switch OPERABILITY is included as part of the OPERABILITY of various interlocks, trip functions, and control rod blocks. Furthermore, the position of the reactor mode switch is adequately controlled by the MODES definition Table (proposed Table 1.1-1). A reactor mode switch position other than Refuel would result in exiting this special test exception; with the associated Technical Specification compliance requirements of the given MODE (more than likely MODE 4 with the reactor mode switch position in Shutdown). In addition, this is a special test exception, and it is not normal to have the reactor mode switch in Refuel. Locking the reactor mode switch in Refuel would require additional actions by the operators to return it to the normal position (Shutdown). Also, to exit the LCO, the reactor mode switch needs to be unlocked to move it to the Shutdown position; but the action of unlocking the reactor mode switch would result in noncompliance with the LCO. Thus to exit the LCO, the plant must currently violate the LCO requirements.

L.2 Alternative requirements have been provided in place of the SHUTDOWN MARGIN and control rod five-by-five array of disarming requirements. The alternatives require all MODE 5 RPS Functions (LCO 3.3.1.1) to be OPERABLE, and MODE 5 requirements for LCO 3.3.8.2, RPS Electric Power Monitoring and LCO 3.9.5, Control Rod OPERABILITY—Refueling, to be made applicable (proposed LCO 3.10.4.c.1). These requirements ensure that if an inadvertent criticality occurs, the RPS will initiate a scram and the withdrawn control rods will insert. In addition, an alternative requirement has been provided in place of the one-rod-out interlock requirement. The alternative will require a control rod

TECHNICAL CHANGES - LESS RESTRICTIVE

L.2 (cont'd) withdrawal block to be inserted (proposed LCO 3.10.4.b.2). This requirement essentially ensures that no additional rods are withdrawn, similar to the one-rod-out interlock. New Surveillances have also been added to perform the applicable SRs for the required LCOs (proposed SR 3.10.4.1) if RPS Functions, RPS Electric Power Monitoring, and control rod OPERABILITY requirements are chosen, and to verify every 24 hours that a control rod withdrawal block is inserted (proposed SR 3.10.4.4) if the block is the chosen requirement. (B)

L.3 The 24 hour Surveillance Frequency provides adequate assurance that the LCO requirements are satisfied. If any Surveillance has not been performed within this interval, control rod withdrawal and CRD removal may not be performed. This ensures the requirements are adequately checked prior to and during control rod withdrawal operations.

ADMINISTRATIVE

A.5 (cont'd) LCO 3.10.8.b.1, which is verified by SR 3.10.8.2, is one option and LCO 3.10.8.b.2, which is verified by SR 3.10.8.3, is the other option. Since these Notes have been added for clarity, they are considered administrative changes.

A.6 The multiple, inoperable withdrawn control rod accumulator requirement is already covered by proposed LCO 3.9.5, since proposed LCO 3.9.5 requires each withdrawn control rod to have an OPERABLE accumulator. Proposed LCO 3.9.5 is applicable in MODE 5, which is the MODE the unit is in when proposed LCO 3.10.8 is being used. Proposed LCO 3.10.8 does not exempt proposed LCO 3.9.5. Therefore, this specific requirement is not included in proposed LCO 3.10.8 and this change is considered administrative.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 A requirement has been added (LCO 3.10.8.f) to ensure adequate CRD charging water pressure is available. This will ensure scram pressure is available, if needed. While current Specification 3.1.3.5, ACTION b.2, has a requirement to place the reactor mode switch in Shutdown if the control rod drive pump is not operating, this new requirement is more restrictive since a specific drive water pressure is now required. An appropriate Surveillance (SR 3.10.8.6) has also been added.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

None

"Specific"

L.1 The Surveillance Frequency has been modified to require CORE ALTERATION verification every 12 hours, instead of once within 30 minutes prior to the start of the SDM test. This will allow the verification to be performed up to 12 hours prior to the start (as described in proposed SR 3.0.1). For the RWM Surveillance, this 30 minute Frequency was effectively a "paper-check", in that the Surveillances required by current Specification 3.1.4.1 were verified current, but not actually required to be performed within 30 minutes prior to the SDM test. The proposed Surveillance deletes this 30 minute paper check, but maintains the requirement

1B

DISCUSSION OF CHANGES
CTS: 3/4.10.5 - OXYGEN CONCENTRATION

1B

ADMINISTRATIVE

None

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 Current Specification 3/4.10.5 has been deleted. This exception is no longer needed at WNP-2 since the Startup Test Program has been completed. This change represents an additional restriction on plant operations through the deletion of an allowed exception to the Limiting Conditions for Operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

None

DISCUSSION OF CHANGES
CTS: 3/4.10.6 - TRAINING STARTUPS

1 B

ADMINISTRATIVE

None

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 Current Specification 3/4.10.6 has been deleted. This exception is no longer needed at WNP-2 since training startups are not performed. This change represents an additional restriction on plant operations through the deletion of an allowed exception to the Limiting Conditions for Operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

None

DISCUSSION OF CHANGES
ITS: CHAPTER 4.0 - DESIGN FEATURES

ADMINISTRATIVE

A.1 Editorial rewording is consistent with the BWR Standard Technical Specifications, NUREG-1434. During its development, certain wording preferences or English language conventions were adopted resulting in no technical changes (actual or interpretational) to the Technical Specifications. In addition, the Figures for the Exclusion Area and Low Population Zones are not needed since a description of the areas have been provided. These descriptions continue to provide the information pertinent to 10 CFR 100 requirements. Therefore, this change is also considered administrative.

A.2 Additional information has been added to better describe the fuel assemblies and control rods. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1434. Since modification to the design must be approved by the NRC, adding detail to the Specification does not result in a technical change.

A.3 The requirement to maintain limits on component cyclic and transient stresses is being moved to Specification 5.5.5 in accordance with the format of the BWR Standard Technical Specifications, NUREG-1434. Any technical changes to this requirement will be addressed in the Discussion of Changes for ITS: 5.5. | (B)

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 A new requirement has been added to specify the nominal distance between fuel bundles seated in the new fuel storage racks (proposed Specification 4.3.1.2.b). The existing Technical Specifications do not contain these limitations on fuel storage in the new fuel storage racks. The addition of this Specification imposes restrictions which will require a formal license amendment request/approval to modify the design. Therefore, this change is an additional restriction on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The specific boundary for the UNRESTRICTED AREA for radioactive gaseous and liquid effluents remains detailed in the FSAR, Section 2.1.1.3. The requirements for and restrictions on locating the UNRESTRICTED AREA must conform to regulations in 10 CFR 20. Compliance with 10 CFR 20 is required by the WNP-2 Operating License. Any changes to this design feature must also

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

LA.4 (cont'd) significant effect on safety, and the criteria of 10 CFR 50.36(c)(4) for including as a Design Feature are not met. Therefore, removing this detail from the Technical Specifications, while maintaining the detail in the FSAR, will not impact safe operation of the facility.

"Specific"

L.1 The water level to which the spent fuel storage pool is designed and maintained to prevent inadvertent draining is being lowered from 605 ft 7 inches to 583 ft 1.25 inches. The current level is the design level it can be drained with the fuel pool gates installed. The new level is the minimum design level to which it can be drained with the gates removed. The gates are removed during refueling outages to transfer fuel between the spent fuel storage pool and the reactor vessel. The minimum design level provides a safe shielding level (i.e., the fuel will remain covered, as required by Regulatory Guide 1.13, Rev. 1) as stated in NUREG-0892, the Safety Evaluation Report related to operation of WNP-2. (B)

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) resulting in more experienced personnel being on shift. In addition, the NRC has previously approved the use of routine 12-hour shifts at numerous other nuclear plants, and no deleterious effects have been noted from those plants use of the 12-hour shift. 1B

DISCUSSION OF CHANGES
ITS: 5.4 - PROCEDURES

ADMINISTRATIVE

A.1 These types of procedures are required by CTS 6.8.1.a, which references Regulatory Guide 1.33. Therefore, it is not necessary to specifically identify each type of procedure. Since the requirements remain, this is considered to be a change in the method of presentation only and, and therefore, is considered an administrative change.

A.2 Procedures to implement the Emergency Plan and the Security Plan are required by 10 CFR 50, Appendix E and 10 CFR 50.54(p). Since conformance with 10 CFR Chapter 1 is a license condition and the Emergency Plan and Security Plan are required to be implemented by 10 CFR Chapter 1, specific identification of these plans is unnecessary duplication. This is a change in the presentation of the requirements only and, therefore, is considered an administrative change.

A.3 Requiring written procedures for ODCM implementation is covered by a more generic item, proposed Specification 5.4.1.e, which requires this activity for all Programs and Manuals. Therefore, it is not necessary to specifically identify each program. Since the requirements remain, this is considered to be a change in the method of presentation only and, therefore, is considered an administrative change.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 Proposed Specification 5.4.1.e is added to the TS that all programs specified in Specification 5.5 have written procedures. ITS 5.5 contains eleven programs that will require (by this proposed TS) procedures to be implemented and maintained. This is an additional restriction on plant operation in that it will be controlled through Technical Specifications.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The details of procedure reviews and approvals including temporary changes contained in CTS 6.8.2 and 6.8.3 are proposed to be relocated to the WNP-2 Quality Assurance Program description in the FSAR. The ability to relocate these requirements is based on regulations and standards that contain these provisions such that duplication in the ITS is not necessary. The requirements for the establishment, maintenance, and implementation of procedures

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.1 (cont'd) related to activities affecting quality are contained in 10 CFR 50, Appendix B, Criterion II and Criterion V; ANSI N18.7-1976; and ANSI N45.2-1971. In accordance with these requirements, the Quality Assurance Program description in the FSAR will include adequate detail with respect to the administrative control of procedures related to activities affecting quality and nuclear safety. In addition, changes to the Quality Assurance Program description in the FSAR will be controlled by the provisions of 10 CFR 50.54(a) to ensure that proper reviews affecting safe operation of the plant are performed. A B

"Specific"

None

PROCEDURES AND PROGRAMS (Continued)

6.8.3 Temporary changes to procedures of Specification 6.8.1a. through j. may be made provided:

a. The intent of the original procedure is not altered;

b. The change is approved by two members of the unit management staff, at least one of whom holds a Senior Operator license on the unit affected; and

c. The change is documented, reviewed by the POC, and approved by the Plant Manager within 14 days of implementation.

(See Discussion of Changes for ITS 5.4, "Procedures," in this Section.)

5.5 6.8.4 The following programs shall be established, implemented, and maintained:

5.5.2 a. Primary Coolant Sources Outside Containment

A program to reduce leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. The systems include the LPCS, HPCS, RHR, RCIC, hydrogen recombiner, process sampling, containment, and the standby gas treatment systems. The program shall include the following:

5.5.2.a 1. Preventive maintenance and periodic visual inspection requirements, and

LD.1

24 month

5.5.2.b 2. Integrated leak test requirements for each system at ~~refueling~~ cycle intervals or less.

b. In-Plant Radiation Monitoring

A program which will ensure the capability to accurately determine the airborne iodine concentration in vital areas under accident conditions. This program shall include the following:

LA.1

1. Training of personnel,

2. Procedures for monitoring, and

3. Provisions for maintenance of sampling and analysis equipment.

5.5.3 c. Post-accident Sampling

A program which will ensure the capability to obtain and analyze reactor coolant, radioactive iodines and particulates in plant gaseous effluents, and containment atmosphere samples under accident conditions. The program shall include the following:

5.5.3.a 1. Training of personnel,

5.5.3.b 2. Procedures for sampling and analysis, and

5.5.3.c 3. Provisions for maintenance of sampling and analysis equipment.

A.7

The provisions of SR 3.0.2 are applicable to the 24 month Frequency for performing integrated system leak test activities.

5.5 PROCEDURES AND PROGRAMS (Continued)

d. Radioactive Effluent Controls Program

5.5.4 A program shall be provided conforming with 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to MEMBERS OF THE PUBLIC from radioactive effluents as low as reasonably achievable. The program (1) shall be contained in the ODCM, (2) shall be implemented by operating procedures, and (3) shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

5.5.4.a 1) Limitations on the operability (Functional Capability) A.1 of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM,

5.5.4.b 2) Limitations on the concentrations of radioactive material released in liquid effluents to UNRESTRICTED AREAS conforming to ~~10 CFR Part 20,~~ Appendix B, Table ~~II~~ I, Column 2, (to 10 CFR 20.1001 – 20.2402) A.2 (10 times the concentration values in A.2)

5.5.4.c 3) Monitoring, sampling and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.~~106~~ 1302 and with the methodology and parameters in the ODCM, A.2

5.5.4.d 4) Limitations on the annual and quarterly doses or dose commitment to a MEMBER OF THE PUBLIC from radioactive materials in liquid effluents released from each unit to UNRESTRICTED AREAS conforming to Appendix I to 10 CFR Part 50,

5.5.4.e 5) Determination of cumulative and projected dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days.

5.5.4.f 6) Limitations on the operability (functional capability) A.1 and use of the liquid and gaseous effluent treatment systems to ensure that the appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a 31 day period would exceed 2 percent of the guidelines for the annual dose or dose commitment conforming to Appendix I to 10 CFR Part 50,

5.5.4.g 7) Limitations on the dose rate resulting from radioactive material released in gaseous effluents to areas beyond the SITE BOUNDARY conforming to the doses associated with 10 CFR Part 20, Appendix B, Table II, Column I, A.2 (Insert 5.5.4.g)

5.5.4.h 8) Limitations on the annual and quarterly air dose resulting from noble gases released in gaseous effluents from each unit to areas beyond the SITE BOUNDARY conforming to Appendix I to 10 CFR Part 50,

A.2

INSERT 5.5.4.q

shall be limited to the following:

1. For noble gases: less than or equal to a dose rate of 500 mrems/yr to the total body and less than or equal to a dose rate of 3000 mrems/yr to the skin, and

2. For iodine-131, iodine-133, tritium, and for all radionuclides in particulate form with half lives > 8 days: less than or equal to a dose rate of 1500 mrems/yr to any organ;

5.0 ADMINISTRATIVE CONTROLS

5.5 PROCEDURES AND PROGRAMS (Continued)

5.5.4 d. Radioactive Effluent Controls Program (continued)

5.5.4.i 9) Limitations on the annual and quarterly dose to a MEMBER OF THE PUBLIC from Iodine-131, Iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days in gaseous effluents released from each unit to areas beyond the SITE BOUNDARY conforming to Appendix I to 10 CFR Part 50,

5.5.4.k 10) Limitations on venting and purging of the containment through the Standby Gas Treatment System to maintain releases as low as reasonably achievable, and

5.5.4.j 11) Limitations on the annual dose or dose commitment to any MEMBER OF THE PUBLIC due to releases of radioactivity and to radiation from uranium fuel cycle sources conforming to 40 CFR Part 190.

e. Radiological Environmental Monitoring Program

A program shall be provided to monitor the radiation and radionuclides in the environs of the plant. The program shall provide (1) representative measurements of radioactivity in the highest potential exposure pathways, and (2) verification of the accuracy of the effluent monitoring program and modeling of environmental exposure pathways. The program shall (1) be contained in the ODCM, (2) conform to the guidance of Appendix I to 10 CFR Part 50, and (3) include the following: LA.2

1) Monitoring, sampling, analysis and reporting of radiation and radionuclides in the environment in accordance with the methodology and parameters in the ODCM.

2) A Land Use Census to ensure that changes in the use of areas at and beyond the SITE BOUNDARY are identified and that modifications to the monitoring program are made if required by the results of this census, and

3) Participation in the Interlaboratory Comparison Program to ensure that independent checks on the precision and accuracy of the measurements of radioactive materials in environmental sample matrices are performed as part of the quality assurance program for environmental monitoring.

5.5.12 f. Primary Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing for the primary containment as required by 10 CFR 50.54(o) and 10 CFR 50 Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines of Regulatory Guide 1.163 dated September 1995, "Performance-Based Containment Leak-Test Program", as modified by the following exceptions: B

1. Compensation for flow meter inaccuracies in excess of those specified in standard ANSI/ANS 56.8-1994 will be accomplished by increasing the actual instrument reading by the amount of the full scale inaccuracy when assessing the effect of local leak rates against the criteria established in Technical Specification 3.6.1.2.b.

Specification 5.5

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3/4.6 CONTAINMENT SYSTEMS

3/4.6.1 PRIMARY CONTAINMENT

PRIMARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.1.1 PRIMARY CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2* and 3.

ACTION:

Without PRIMARY CONTAINMENT INTEGRITY, restore PRIMARY CONTAINMENT INTEGRITY within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.1 PRIMARY CONTAINMENT INTEGRITY shall be demonstrated:

a. After each closing of each penetration subject to Type B testing, except the primary containment air locks, if opened following Type A or B test, by leak rate testing the seals with gas at P_a, and verifying that when the measured leakage rate for these seals is added to the leakage rates determined pursuant to Surveillance Requirement 4.6.1.2.d for all other Type B and C penetrations, the combined leakage rate is less than ~~or equal to~~ 0.60 L_a. (A.12) ⊢ 5.5.12.a

b. At least once per 31 days by verifying that all primary containment penetrations** not capable of being closed by OPERABLE containment automatic isolation valves and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic valves secured in position, except as provided in Table 3.6.3-1 of Specification 3.6.3. (B)

c. By verifying each primary containment air lock is in compliance with the requirements of Specification 3.6.1.3.

d. By verifying the suppression chamber is in compliance with the requirements of Specification 3.6.2.1.

See Discussion of Changes for ITS: 3.6.1.1, in Section 3.6

* See Special Test Exception 3.10.1.

**Except valves, blind flanges, and deactivated automatic valves which are within the primary containment or other areas administratively controlled to prohibit access for reasons for personnel safety (i.e., radiation and temperature) and are locked, sealed, or otherwise secured in the closed position (1-1/2 inch and smaller valves connected to vents, drains or test connections must be closed but need not be sealed). Valves inside containment shall be verified closed following primary containment de-inerting, but verification is not required more often than once per 92 days. Valves in other administratively controlled areas shall be verified closed during each COLD SHUTDOWN, but verification is not required more often than once per 31 days.

Specification 5.5

See Discussion of Changes for ITS 3.6.1.1, in Section 3.6

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CONTAINMENT SYSTEMS

PRIMARY CONTAINMENT LEAKAGE

LIMITING CONDITION FOR OPERATION

3.6.1.2 Primary containment leakage rates shall be limited to: 5.5.12.a

a. An overall integrated leakage rate of less than or equal to L_a, 0.50 percent by weight of the containment air per 24 hours at P_a. 5.5.12

b. A combined leakage rate of less than or equal to 0.60 L_a for all penetrations and all valves listed in Table 3.6.3-1 except for main steam line isolation valves* (and valves which are hydrostatically leak tested per Table 3.6.3-1), subject to Type B and C tests when pressurized to P_a. A.1.2 5.5.12.a

c. *Less than or equal to 11.5 scf per hour for any one main steam line isolation valve when tested at P_t, 25.0 psig.

d. A combined leakage rate of less than or equal to 1 gpm times the total number of ECCS and RCIC containment isolation valves in hydrostatically tested lines which penetrate the primary containment, when tested at 1.10 P_a.

APPLICABILITY: When PRIMARY CONTAINMENT INTEGRITY is required per Specification 3.6.1.1.

ACTION:

With:

a. The measured overall integrated primary containment leakage rate exceeding 0.75 L_a, or 5.5.12.a A.1.2

b. The measured combined leakage rate for all penetrations and all valves listed in Table 3.6.3-1, except for main steam line isolation valves* (and valves which are hydrostatically leak tested per Table 3.6.3-1), subject to Type B and C tests exceeding 0.60 L_a, or

c. The measured leakage rate exceeding 11.5 scf per hour for any one main steam line isolation valve, or

d. The measured combined leakage rate for all ECCS and RCIC containment isolation valves in hydrostatically tested lines which penetrate the primary containment exceeding 1 gpm times the total number of such valves,

restore:

a. The overall integrated leakage rate(s) to less than or equal to 0.75 L_a, and 5.5.12.a A.1.2

b. The combined leakage rate for all penetrations and all valves listed in Table 3.6.3-1, except for main steamline isolation valves* and valves which are hydrostatically leak tested per Table 3.6.3-1, subject to Type B and C tests to less than or equal to 0.60 L_a, and 5.5.12.a A.1.2

5.5.12.a

*Exemption to Appendix J of 10 CFR Part 50.

Specification 5.5

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CONTAINMENT SYSTEMS

PRIMARY CONTAINMENT AIR LOCKS

LIMITING CONDITION FOR OPERATION

3.6.1.3 Each primary containment air lock shall be OPERABLE with:

a. The interlock operable and engaged such that both doors cannot be opened simultaneously, and

b. Both doors closed except when the air lock is being used for normal transit entry and exit through the containment, and

c. An overall air lock leakage rate of less than or equal to 0.05 L_a at P_a. 5.5.12.b.1

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2* and 3.

ACTION:

a. With the interlock mechanism inoperable:

1. Maintain at least one operable air lock door closed and either return the interlock to service within 24 hours or lock at least one operable air lock door closed.

2. Operation may then continue until the interlock is returned to service provided that one of the air lock doors is verified locked closed prior to each closing of the shield door and at least once per shift while the shield door is open.

3. Personnel passage through the air lock is permitted provided an individual is dedicated to assure that one operable air lock door remains locked at all times so that both air lock doors cannot be opened simultaneously.

4. The provisions of Specification 3.0.4 are not applicable.

b. With one primary containment air lock door inoperable:

1. Maintain at least the OPERABLE air lock door closed and either restore the inoperable air lock door to OPERABLE status within 24 hours or lock the OPERABLE air lock door closed.

2. Operation may then continue until performance of the next required overall air lock leakage test provided that the OPERABLE air lock door is verified to be locked closed immediately prior to each closing of the shield door and at least once per shift while the shield door is open.

See Discussion of Changes for ITS: 3.6.1.2, IN Section 3.6

B

*See Special Test Exception 3.10.1.

Specification 5.5

CONTAINMENT SYSTEMS

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

3. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

4. The provisions of Specification 3.0.4 are not applicable.

c. With the primary containment air lock inoperable, except as a result of an inoperable air lock door or an inoperable interlock mechanism, maintain at least one air lock door closed; restore the inoperable air lock to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.3 Each primary containment air lock shall be demonstrated OPERABLE:

a. By verifying interlock operation (i.e., that only one door in each air lock can be opened at a time).

1. Prior to using the air lock in Operating Conditions 1, 2 and 3 but not required more than once per 6 months,

2. Following maintenance that could affect the interlock mechanism.

b. Within 72 hours following each closing, except when the air lock is being used for multiple entries, then at least once per 72 hours, by verifying seal leakage rate less than or equal to 0.025 L_a when the gap between the door seals is pressurized to 10 psig. (B)

5.5.12.6.2

c. By conducting an overall air lock leakage test at P_a, and by verifying that the overall air lock leakage rate is within its limit:

5.5.12.6.1

1. At intervals determined in accordance with 10 CFR 50 Appendix J using the methods and provisions outlined in the Primary Containment Leakage Rate Testing Program described in Specification 6.8.4.f, and

2. Prior to establishing PRIMARY CONTAINMENT INTEGRITY when maintenance had been performed on the air lock that could affect the air lock sealing capability*.

*Exception to Appendix J of 10 CFR 50.

See Discussion of Changes for ITS: 3.6.1.2, in this Section

HIGH RADIATION AREA (Continued)

where no enclosure exists for purposes of locking, and no enclosure can be reasonably constructed around the individual areas, then that area shall be barricaded, conspicuously posted, and a flashing light shall be activated as a warning device. In lieu of the stay time specification of the RWP, continuous surveillance, direct or remote (such as use of closed circuit TV cameras) may be made by personnel qualified in radiation protection procedures to provide positive exposure control over the activities within the area.

See Discussion of Changes for ITS: Section 5.7, "High Radiation Area" in this Section.

6.13 PROCESS CONTROL PROGRAM (PCP)

See Discussion of changes for CTS: 6.13, "Process Control Program", in this Section.

Licensee-initiated changes to the PCP:

a. Shall be documented and records of reviews performed shall be retained as required by Specification 6.10.3n. This documentation shall contain:

1) Sufficient information to support the change together with the appropriate analyses or evaluations justifying the change(s) and

2) A determination that the change will maintain the overall conformance of the solidified waste product to existing requirements of Federal, State or other applicable regulations.

b. Shall become effective after review and acceptance by the PGC and the approval of the Plant Manager.

5.5.1 6.14 OFFSITE DOSE CALCULATION MANUAL (ODCM)

5.5.1.c Licensee-initiated changes to the ODCM:

5.5.1.c.1 a. Shall be documented and records of reviews performed shall be retained ~~as required by Specification 6.10.3n.~~ This documentation shall contain: A.3

5.5.1.c.1(a) 1) Sufficient information to support the change together with the appropriate analyses or evaluations justifying the change(s) and

5.5.1.c.1(b) 2) A determination that the change will maintain the level of radioactive effluent control required by 10 CFR 20.1302, 40 CFR Part 190, 10 CFR 50.36a, and Appendix I to 10 CFR Part 50 and not adversely impact the accuracy or reliability of effluent, dose or setpoint calculations. A.2

5.5.1.c.2 b. Shall become effective after review and acceptance by the POC and the approval of the Plant Manager. General A.4

5.5.1.c.3 c. Shall be submitted to the Commission in the form of a complete, legible copy of the entire ODCM as a part of or concurrent with the Radioactive Effluent Release Report for the period of the report in which any changes to the ODCM were made. Each change shall be identified by markings in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (e.g., month/year) the change was implemented.

5.5.1 OFFSITE DOSE CALCULATION MANUAL

1.27 The OFFSITE DOSE CALCULATION MANUAL (ODCM) shall contain the current methodology and parameters used in the calculation of offsite doses due to radioactive gaseous and liquid effluents in the calculation of gaseous and liquid effluent monitoring alarm/trip setpoints and in the conduct of the environmental radiological monitoring program. The ODCM shall also contain (1) the Radioactive Effluent Controls and Radiological Environmental Monitoring ~~Programs required by Section 6.8.3~~ activities and (2) descriptions of the information that should be included in the Radioactive Effluent Release Reports required by Specifications ~~6.9.1.10~~ 5.6.2 A.5 and ~~6.9.1.11~~ 5.6.3 A.5

Annual Radiological Environmental Operating and A.5

5.5.1.a

5.5.1.b

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Specification 5.5

5.5 METEOROLOGICAL TOWER LOCATION

5.5.1 The meteorological tower shall be located as shown on Figure 5.1-1.

5.6 FUEL STORAGE

CRITICALITY

5.6.1 The spent fuel storage racks are designed and shall be maintained with:

a. A k_{eff} equivalent to less than or equal to 0.95 when flooded with unborated water, including all calculational uncertainties and biases as described in Section 9.1.2 of the FSAR.

b. A nominal 6.5-inch center-to-center distance between fuel assemblies placed in the storage racks.

5.6.1.2 The k_{eff} for new fuel for the first core loading stored dry in the spent fuel storage racks shall not exceed 0.95 when flooding with water is assumed.

DRAINAGE

5.6.2 The spent fuel storage pool is designed and shall be maintained to prevent inadvertent draining of the pool below elevation 605 ft 7 in.

CAPACITY

5.6.3 The spent fuel storage pool is designed and shall be maintained with a storage capacity limited to no more than 2658 fuel assemblies.

5.5 5.7 COMPONENT CYCLIC OR TRANSIENT LIMIT

5.5 5.7.1 The components identified in Table ~~5.7.1-1~~ are designed and shall be maintained within the cyclic or transient limits ~~of Table 5.7.1-1.~~

FSAR

3.9.1, Note 1

LA.3

See Discussion of Changes in ITS: chapter 4.0 "Design Features"

TABLE 5.7.1-1

COMPONENT CYCLIC OR TRANSIENT LIMITS

COMPONENT	CYCLIC OR TRANSIENT LIMIT	DESIGN CYCLE OR TRANSIENT
Reactor	117 heatup and 111 cooldown cycles	100°F to 560°F to 100°F
	80 step change cycles	Loss of feedwater heaters
	180 reactor trip cycles	100% to 0% of RATED THERMAL POWER
	130 hydrostatic pressure tests	Pressurized to ≥ 930 psig and ≤ 1250 psig
	123 Bolt up cycles	Operations Cycle at 70°F

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L43

Specification 5.5

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Specification 5.5

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APPLICABILITY

SURVEILLANCE REQUIREMENTS

See Discussion of Changes for ITS: Section 3.0, "LCO and SR Applicability"

4.0.1 Surveillance Requirements shall be met during the OPERATIONAL CONDITIONS or other conditions specified for individual Limiting Conditions for Operation unless otherwise stated in an individual Surveillance Requirement.

4.0.2 Each Surveillance Requirement shall be performed within the specified Surveillance interval with a maximum allowable extension not to exceed 25% of the specified surveillance interval.

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

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

5.5.6 4.0.5 Surveillance Requirements for inservice inspection and testing of ASME Code Class 1, 2, & 3 components shall be applicable as follows: LA.4

a. Inservice inspection of ASME Code Class 1, 2, and 3 components and inservice testing of ASME Code Class 1, 2, and 3 pumps and valves shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR 50, Section 50.55a. LA.4 LA.5

pumps and valves LA.4

5.5.6.a b. Surveillance intervals specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda for the inservice inspection and testing activities required by the ASME Boiler and Pressure Vessel Code and applicable Addenda shall be applicable as follows in these Technical Specifications: LA.4

ASME Boiler and Pressure Vessel Code and applicable Addenda terminology for inservice inspection and testing activities	Required frequencies for performing inservice inspection and testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every two years	At least once per 731 days

APPLICABILITY

SURVEILLANCE REQUIREMENTS (Continued) Specification 5.5

5.5.6.b c. The provisions of Specification 4.0.2 are applicable to the above required frequencies for performing inservice inspection and testing activities. LA.4

d. Performance of the above inservice inspection and testing activities shall be in addition to other specified Surveillance Requirements. A.6

5.5.6.d e. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any Technical Specification.

f. An inservice inspection program for piping identified in NRC Generic Letter 88-01 shall be performed in accordance with the NRC staff positions on schedule, methods, personnel and sample expansion included in this Generic Letter or in accordance with alternate measures approved by the NRC. LA.4

5.5.6.c The provisions of SR 3.0.3 are applicable to inservice testing activities; and A.7

CONTAINMENT SYSTEMS

Specification 5.5

proposed 5.5.7 — A.8

SURVEILLANCE REQUIREMENTS (Continued)

b. At least once per 18 (24 — LD.1) months or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire, or chemical release in any ventilation zone communicating with the subsystem by:

5.5.7.

Section 10 addition — L.1

Section 11 addition — A.9

5.5.7.a / 5.5.7.b

1. Verifying that the subsystem satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Regulatory Positions C.5.a, C.5.c, and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and ANSI-N510-1989, Sections 10 and 11 at a system flow rate of 4457 cfm ± 10%.

LA.6

5.5.7.c — A.9

2. Verifying ~~within 31 days after removal~~ that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of ~~Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2~~, March 1978, for a methyl iodide penetration of less than 0.175%; and

ASTM-D3803-1986 (method B for the SGT system).

at a relative humidity of 70%

A.9 — B

5.5.7.d

3. Verifying a subsystem flow rate of 4457 cfm + 10% during system operation when tested in accordance with ANSI N510-~~1980~~ 1989 — A.9

5.5.7.c — LA.6

c. After every 720 hours of charcoal adsorber operation by verifying ~~within 31 days after removal~~ that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of ~~Regulatory Guide 1.52, Revision 2, March 1978~~, for a methyl iodide penetration of less than 0.175%.

ASTM D3803-1986 (Method B for the SGT System)

at a relative humidity of 70%

A.9 — B

d. At least once per 18 (24 — LD.1) months by:

5.5.7.d

1. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 8 inches water gauge while operating the filter train at a flow rate of 4457 cfm ± 10%.

See Discussion of Changes for ITS 3.6.4.3, "SGT System" in section 3.6.

2. Verifying that the filter train starts and isolation dampers open on each of the following test signals.

   a. Manual initiation from the control room, and

   b. Simulated automatic initiation signal.

3. Verifying that the filter cooling bypass dampers can be manually opened and the fan can be manually started.

5.5.7.e

4. Verifying that the heaters dissipate 20.7 ± 2.1 kW when tested in accordance with ANSI N510-~~1980~~ 1989 — A.9

Specification 5.5

SURVEILLANCE REQUIREMENTS (Continued)

5.5.7 e. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter bank satisfies the inplace penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-~~1980~~ 1989 A.9 while operating the system at a flow rate of 4457 cfm ± 10%. (5.5.7.c)

5.5.7. f. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorber bank satisfies the inplace penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-~~1980~~ 1989 A.9 for a halogenated hydrocarbon refrigerant test gas while operating the system at a flow rate of 4457 cfm ± 10%. (5.5.7.b)

c. At least once per 24 (18) months or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire, or chemical release in any ventilation zone communicating with the train by: LD.1

5.5.7

1. Verifying that the train satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Regulatory Positions C.5.a, C.5.c, and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, when operating at a flow rate of 1000 cfm + 10%. Section 10 addition L.1 Section 11 addition A.9 and ANSI N510-1980, Sections 10 and 11 5.5.7.a 5.5.7.b

2. Verifying ~~within 31 days after removal~~ LA.6 that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of ~~Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978~~, for a methyl iodide penetration of less than 1.0%; and A.9 ASTM-D3803-1986 (Method A for the CREF System) 5.5.7.c

3. Verifying a train flow rate of 1000 cfm ± 10% during train operation when tested in accordance with ANSI N510-~~1980~~ 1989. A.9 5.5.7.d

d. After every 720 hours of charcoal adsorber operation by verifying ~~within 31 days after removal~~ LA.6 that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Positon C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of ~~Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978~~, for a methyl iodide penetration of less than 1.0%. ASTM-D3803-1986 (Method A for the CREF System) at a relative humidity of 70% A.9 5.5.7 5.5.7.c

e. At least once per 24 (18) months by: LD.1

1. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 6 inches water gauge while operating the train at a flow rate of 1000 cfm ± 10%. 5.5.7.d

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B

PLANT SYSTEMS

Specification 5.5

SURVEILLANCE REQUIREMENTS (Continued)

See Discussion of Changes for ITs: 3.7.3, CREF System, in section 3.7.

2. Verifying that on each of the below pressurization mode actuation test signals, the train automatically switches to the pressurization mode of operation and the control room is maintained at a positive pressure of 1/8 inch water gauge relative to the outside atmosphere during train operation at a flow rate less than or equal to 1000 cfm:
   a) Drywell pressure-high,
   b) Reactor vessel water level-low, and
   c) Reactor Building exhaust plenum-high radiation.

5.5.7.e 3. Verifying that the heaters dissipate 5.0 ± 0.5 kW when tested in accordance with ANSI N510-~~1980~~ 1989 A.9

5.5.7 f. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter bank satisfies the inplace penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-~~1980~~ 1989 A.9 while operating the train at a flow rate of 1000 cfm ± 10%. (5.5.7.a)

5.5.7 g. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorber bank satisfies the inplace penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-~~1980~~ 1989 A.9 for a halogenated hydrocarbon refrigerant test gas while operating the train at a flow rate of 1000 cfm ± 10%. (5.5.7.b)

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3/4.11.1 LIQUID EFFLUENTS

LIQUID HOLDUP TANKS

Specification 5.5.

LIMITING CONDITION FOR OPERATION

3.11.1.1 - Relocated to ODCM.

3.11.1.2 - Relocated to ODCM

3.11.1.3 - Relocated to ODCM

add proposed Specification 5.5.8 A.10

5.5.8.b 3.11.1.4 The quantity of radioactive material contained in any outside temporary tanks shall be limited to the limits calculated in the ODCM such that a complete release of the tank contents would not result in a concentration at the nearest offsite potable water supply that would exceed the limits specified in 10 CFR Part 20 Appendix B Table II.

Table 2, Column 2 to 10CFR 20.1001-20.2402 A.2 B

A.2 LA.7 B

APPLICABILITY: At all times.

ACTION:

a. With the quantity of radioactive material in any of the above listed tanks exceeding the above limit, immediately suspend all additions of radioactive material to the tank, within 48 hours reduce the tank contents to within the limit, and describe the events leading to this condition in the next Semiannual Radioactive Effluent Release Report.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

5.5.8.b 4.11.1.4 The quantity of radioactive material contained in each of the above listed tanks shall be determined to be within the above limit by analyzing a representative sample of the tank's contents at least once per 7 days when radioactive materials are being added to the tank.

LA.7

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3/4.11 RADIOACTIVE EFFLUENTS

3/4.11.2 GASEOUS EFFLUENTS

EXPLOSIVE GAS MIXTURE

Specification 5.5

LIMITING CONDITION FOR OPERATION

3.11.2.1 - Relocated to ODCM

3.11.2.2 - Relocated to ODCM

3.11.2.3 - Relocated to ODCM

3.11.2.4 - Relocated to ODCM

3.11.2.5 - Relocated to ODCM

A.10

add proposed Specification 5.5.8

5.5.8.c 3.11.2.6 The concentration of hydrogen in the main condenser offgas treatment system shall be limited to ~~less than or equal to 4%~~ by volume. LA-7

APPLICABILITY: Whenever the main condenser steam jet air ejector (evacuation) system is in operation.

ACTION:

a. With the concentration of hydrogen in the main condenser offgas treatment system exceeding the limit, restore the concentration to within the limit within 48 hours.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

LA-7

SURVEILLANCE REQUIREMENTS

5.5.8.c 4.11.2.6 The concentration of hydrogen in the main condenser offgas treatment system shall be determined to be within the above limits by continuously monitoring the waste gases in the main condenser offgas treatment system with the hydrogen monitors required OPERABLE by Table 3.3.7.12-1 of Specification 3.3.7.12.

LA-7

Specification 5.5

ELECTRICAL POWER SYSTEMS

SURVEILLANCE REQUIREMENTS (Continued)

b. By checking for and removing accumulated free water in the diesel fuel tanks as follows:

1. Check for and drain any accumulated water from the day tanks at least once per 31 days and after each occasion when the diesel is operated for greater than 1 hour.

2. Check for accumulated water at the bottom of the storage tank below the transfer pump every 31 days. Initiate the procedure for pumping off accumulated water within 48 hours of detection.

5.5.9 c. / 5.5.9.a By sampling new diesel fuel in accordance with ASTM D4057-81 prior to addition to the storage tanks and:

1. By verifying in accordance with the tests specified in ASTM D975-81 prior to addition to the storage tanks that the sample has:

5.5.9.a.1 a. 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 or greater than or equal to 0.83 but less than or equal to 0.89 or an API gravity at 60°F of greater than or equal to 27 degrees but less than or equal to 39 degrees.

5.5.9.a.2 b. A kinematic viscosity at 40°C of greater than or equal to 1.9 centistokes, but less than or equal to 4.1 centistokes, if gravity was not determined by comparison with the supplier's certification.

5.5.9.a.2 c. A flash point equal to or greater than 125°F, and

5.5.9.a.3 d. A water and sediment content of less than or equal 0.05 volume percent per ASTM D1796-83 or a Clear and Bright appearance with proper color when tested in accordance with ASTM D4176-82.

2. By verifying within 31 days of obtaining the sample that the other properties specified in Table 1 of ASTM D975-81 are met when tested in accordance with ASTM D975-81 except that the analysis for sulfur may be performed in accordance with ASTM D1552-79 or ASTM D2622-82.

5.5.9.b

5.5.9.c d. By obtaining a sample, at least once every 31 days, of fuel oil from the storage tanks in accordance with ASTM D2276-78, and verifying within 1 week after obtaining the sample that the total particulate contamination is less than 10 mg/liter when checked in accordance with ASTM D2276-78, Method A.

e. At least once per 18 months, during shutdown, by:

1. Subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for this class of standby service.

2. Verifying the diesel generator capability to reject a load of greater than or equal to 1377 kW for DG-1, greater than or equal to 1377 kW for DG-2, and greater than or equal to

See Discussion of Changes for ITS: 3.8.1, "AC Sources - Operating," in Section 3.8.

See Discussion of Changes for ITS: 3.8.3, "Diesel Fuel Oil, Lube Oil, and Starting Air," in Section 3.8

add proposed 5.5.A

add proposed Specifications 5.5.10 and 5.5.11

ADMINISTRATIVE

A.8 (cont'd) frequency extensions do apply, since these SRs are not normally applied to frequencies identified in the Administrative Controls Chapter of the Technical Specifications. Since this change is a clarification needed to maintain provisions that would be allowed in the LCO sections of the Technical Specifications, it is considered administrative.

A.9 Current Technical Specifications for in-place charcoal adsorber testing of the SGT and CREF Systems reference Regulatory Position C.5.a and C.5.d of Regulatory Guide (RG) 1.52, Revision 2, March 1978. Proposed Technical Specification 5.5.7.b references RG 1.52, Revision 2, Section C.5.d and ANSI N510-1989, Section 11. Current Technical Specifications for laboratory testing of the SGT and CREF Systems reference the testing criteria of RG 1.52, Revision 2, Section C.6.a. Proposed Technical Specification 5.7.7.c references ASTM D3803-1986 at a specific method and relative humidity. Current Technical Specifications for the flow rate, pressure drop, and heater tests reference ANSI N510-1980. Proposed Specifications 5.5.7.a through 5.5.7.e references ANSI N510-1989. The changes to the new references are an update to the latest revision but do not change the current testing requirements or acceptance criteria. Therefore, these changes are considered administrative.

A.10 The outside temporary liquid radwaste tank requirements and offgas system hydrogen requirements have been placed in a program in the proposed Administrative Controls Chapter. As such, a general program statement has been added. In addition, a statement of applicability of SR 3.0.2 and SR 3.0.3 is needed to clarify that the allowances for surveillance frequency extensions do apply, since these SRs are not normally applied to frequencies identified in the Administrative Controls Chapter of the Technical Specifications. Since this change is a clarification needed to maintain provisions that would be allowed in the LCO sections of the Technical Specifications, it is considered administrative in nature.

A.11 The diesel fuel oil testing requirements have been placed in a program in the proposed Administrative Controls Chapter. As such, a general program statement has been added. Also, a statement of applicability of SR 3.0.2 and SR 3.0.3 is needed to clarify that the allowances for Surveillance Frequency extensions do apply, since these SRs are not normally applied to frequencies identified in the Administrative Controls Chapter of the Technical Specifications. Since this change is a clarification needed to maintain provisions that are currently allowed in the LCO sections of the Technical Specifications, it is considered administrative. (B)

A.12 The limits in Appendix J is $< 0.60\ L_a$ and $< 0.75\ L_a$, not $\leq 0.60\ L_a$ and $\leq 0.75\ L_a$. Thus, the limits are reflected in accordance with Appendix J requirements.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 Two new programs are included in the proposed Technical Specifications. These programs are:

5.5.10 Technical Specification (TS) Bases Control
5.5.11 Safety Function Determination Program (SFDP)

The Safety Function Determination Program is included to support implementation of the support system OPERABILITY characteristics of the Technical Specifications. The TS Bases Control Program is provided to specifically delineate the appropriate methods and reviews necessary for a change to the Technical Specification Bases.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The details contained in CTS 6.8.4.b, "In-Plant Radiation Monitoring," are proposed to be relocated to the FSAR, where it currently resides (FSAR, Appendix B). This program is required by the WNP-2 commitment to NUREG-0737, Item III.D.3.3, as stated in the FSAR, Appendix B. This program contains controls to ensure the capability to accurately determine the airborne iodine concentration in vital areas under accident conditions. This program is designed to minimize radiation exposure to plant personnel post-accident and has no impact on nuclear safety or the health and safety of the public. The training aspect of the program is accomplished as part of the continual training program for personnel in the cognizant organizations, as well as during the training for those individuals responsible for implementing the Radiological Emergency Planning procedures. Provisions for monitoring and performing maintenance of the sampling and analysis equipment are addressed in chemistry and radiation protection procedures. Changes to the FSAR are controlled by the provisions of 10 CFR 50.59.

LA.2 The details contained in CTS 6.8.4.e, "Radiological Environmental Monitoring Program," are proposed to be relocated to the Offsite Dose Calculation Manual (ODCM). This program is a redundant verification of the effectiveness of the effluent monitoring program contained in the ODCM and specified in the administrative controls section of the ITS. The relocated program has no impact or effect on nuclear safety of the plant. Proposed Specification 5.5.1 for the ODCM requires the ODCM to contain these activities. Changes to the ODCM will be controlled by the provisions of proposed Specification 5.5.1.c.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

LA.3 Details of the components governed by this Specification are proposed to be relocated to the FSAR. These details are not necessary to be included in the Technical Specifications. The requirement to monitor the cyclic and transient occurrences is maintained as a program in proposed Specification 5.5.5. Changes to the FSAR are controlled by the provisions of 10 CFR 50.59.

LA.4 Details of the Inservice Inspection Program (ISI) in the CTS are proposed to be relocated to the plant controlled ISI Program. The ISI Program is required by 10 CFR 50.55a to be performed in accordance with ASME Section XI. Compliance with 10 CFR 50.55a is required by the WNP-2 Operating License. The WNP-2 ISI Program, outside of the CTS, implements the applicable provisions of ASME Section XI. Generic Letter 88-01 provides an ISI Program for piping in accordance with the NRC staff positions on schedule, methods, personnel, and sample expansion or in accordance with alternate measures approved by the NRC staff. WNP-2 commitments to Generic Letter 88-01 are documented to the NRC in letters dated July 26, 1988 and July 20, 1989, and do not need to be repeated in the ITS. Regulations and WNP-2 commitments to the NRC contain the necessary programmatic requirements for ISI without repeating them in the ITS. Changes to the plant controlled ISI Program will be controlled by the provisions of 10 CFR 50.59. In addition, since the Inservice Testing Program is the only requirement remaining, the reference to ASME Code Class 1, 2, and 3 "components" has been changed to "pumps and valves" for clarity. Pumps and valves are the only components related to the Inservice Testing Program (as described in CTS 4.0.5.a). 1B

LA.5 Details of the Inservice Testing Program (IST) in the CTS are proposed to be relocated to the plant controlled IST Program. The relocated requirements are duplicated in 10 CFR 50.55a, which requires the implementation of ASME, Section XI and applicable addenda, for inservice testing of ASME Code Class 1, 2, and 3 pumps and valves. Compliance with 10 CFR 50.55a is required by the WNP-2 Operating License. Therefore, it is not necessary to retain the provisions proposed to be relocated in the ITS. Changes to the plant controlled IST program will be controlled by the provisions of 10 CFR 50.59.

LA.6 Details of the methods for implementing this specification are relocated to the procedures that implement the VFTP. The requirements of Specification 5.5.7 are adequate to ensure the required ventilation filter testing is performed. SR 3.6.4.3.2 of Specification 3.6.4.3, Standby Gas Treatment (SGT) System, which requires ventilation filter testing of the SGT System to be performed in accordance with the VFTP, and SR 3.7.4.3.2 of Specification 3.7.3, Control Room Emergency Filtration (CREF) System, which requires ventilation filter testing of the CREF System to be performed in accordance with the VFTP, and the requirements of Specification 5.5.7 provide adequate regulatory controls over the testing requirements proposed to be relocated.

 CONTROLLED COPY Current Specification 6.7

6.7 SAFETY LIMIT VIOLATION

A.1 6.7.1 The following actions shall be taken in the event a Safety Limit is violated:

a. The NRC Operations Center shall be notified by telephone as soon as possible and in all cases within 1 hour. The Assistant Managing LA.1 Director for Operations and the CNSRB shall be notified.

b. A Safety Limit Violation Report shall be prepared. The report shall A.1 be reviewed by the POC. This report shall describe (1) applicable LA.1 circumstances preceding the violation, (2) effects of the violation upon unit components, systems, or structures, and (3) corrective A.1 action taken to prevent recurrence. B

c. The Safety Limit Violation Report shall be submitted to the Commission, the CNSRB, and the Assistant Managing Director for LA.1 Operations.

d. Critical operation of the unit shall not be resumed until authorized A.1 by the Commission.

6.8 PROCEDURES AND PROGRAMS

6.8.1 Written procedures shall be established, implemented, and maintained covering the activities referenced below:

a. The applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978.

b. The applicable procedures required to implement the requirements of NUREG-0737.

c. Refueling operations.

d. Surveillance and test activities of safety-related equipment.

e. Security Plan implementation.

f. Emergency Plan implementation.

g. Fire Protection Program implementation.

h. PROCESS CONTROL PROGRAM implementation.

i. OFFSITE DOSE CALCULATION MANUAL implementation.

j. Quality Assurance Program for effluent and environmental monitoring.

6.8.2 Each procedure of Specification 6.8.1, and changes thereto, shall be reviewed by the POC and shall be approved by the Plant Manager prior to implementation and reviewed periodically as set forth in administrative procedures.

See Discussion of Changes for ITS: 5.4, "Procedures" in this section.

DISCUSSION OF CHANGES
CTS: 6.7 - SAFETY LIMIT VIOLATION

ADMINISTRATIVE

A.1 The current Safety Limit Violation requirements of Specification 6.7.1, as they relate to NRC notification (portions of Specification 6.7.1.a, 6.7.1.b, and 6.7.1.c) and permission to restart the unit (Specification 6.7.1.d) are duplicative of requirements located in 10 CFR 50.36(c)(1). Since WNP-2 is required by the Operating License to comply with 10 CFR 50, the removal of these requirements from Technical Specifications is considered administrative. (B)

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

None

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The requirement for notification of the Assistant Managing Director for Operations and the CNSRB in the event of a Safety Limit violation, the requirement for the POC to review the Safety Limit Violation Report and to submit the Safety Limit Violation Report to the CNSRB and the Assistant Managing Director for Operations (Vice President, Nuclear Operations) are proposed to be relocated to plant procedures. Given that the notification occurs following the Safety Limit violation and that the Safety Limit Violation Report is an after-the-fact report, the proposed relocated requirements are clearly not necessary to assure operation of the unit in a safe manner. Additionally, in the event of a Safety Limit violation, 10 CFR 50.36(c)(1) does not allow operation of the unit to be resumed until authorization is received from the NRC. Changes to the relocated requirements in plant procedures will be controlled by the provisions of 10 CFR 50.59. In addition, the Safety Limit Violation Report has been replaced with an LER requirement, consistent with 10 CFR 50.36(c)(1). (B)

"Specific"

None

DISCUSSION OF CHANGES
CTS: 6.10 - RECORD RETENTION

ADMINISTRATIVE

None

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

None

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The details contained in CTS 6.10 are proposed to be relocated to the WNP-2 Quality Assurance Program description in the FSAR. The requirement for retention of records related to activities affecting quality is contained in 10 CFR 50, Appendix B, Criterion XVII and other sections of 10 CFR 50 that are applicable to WNP-2 (i.e., 10 CFR 50.71, 10 CFR 73, etc.). These record retention requirements provide a record of certain activities important to plant safety, but the records themselves do not assure safe operation of the facility since review of these records is a post-compliance review. Relocation of these CTS provisions to the Quality Assurance Program description in the FSAR will provide adequate controls over record retention requirements for WNP-2. The Quality Assurance Program description in the FSAR will be revised to contain adequate detail with respect to these requirements to ensure recordkeeping is implemented in an appropriate manner. Changes to the Quality Assurance Program description in the FSAR will be controlled by the provisions of 10 CFR 50.54(a) to help ensure that appropriate reviews of any changes are performed.

"Specific"

None

NO SIGNIFICANT HAZARDS EVALUATION
ITS: 3.3.4.2 - ATWS-RPT SYSTEM INSTRUMENTATION

L.1 CHANGE

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

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

   This change will identify Required Actions based on trip Function capability rather than single trip system OPERABILITY. The ATWS event is not a design basis event. In addition, the ATWS-RPT instrumentation is not assumed to be an initiator of any analyzed event. Therefore, this change does not significantly increase the probability of a previously analyzed accident. Either condition results in decreased capability with regard to single failures; however, as long as one Function is available, single failure capability can be restored or a shutdown will eventually be required in accordance with the proposed Required Actions. Therefore, this change does not significantly increase the probability or consequences of a previously analyzed accident.

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

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

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

   This change does not involve a significant reduction in a margin of safety since the ATWS event is not a design basis event and at least one Function continues to provide the required ATWS-RPT actuation capability.

L.3 CHANGE

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

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

   This change will allow one or more inoperable channels to be placed in the tripped condition to allow continued operation for an unlimited amount of time instead of only until the next CHANNEL FUNCTIONAL TEST. Tripped channels in the loss of power actuation logic are not considered as an initiator for any accidents previously analyzed. Therefore, this change does not significantly increase the probability of a previously analyzed accident. A tripped channel continues to provide the required safety function. Therefore, this change does not significantly increase the consequences of a previously analyzed accident.

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

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

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

   This change does not involve a significant reduction in a margin of safety since the safety functions continue to provide the required loss of power actuation capability, including single failure conditions.

L.4 CHANGE

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

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

   This change does not result in any hardware or operating procedure changes. The LOP instrumentation is not assumed to be an initiator of any analyzed event. The instrumentations role is in mitigating and thereby limiting the consequences of design basis events. The instrumentation actuates to ensure the diesel generators are initiated to ensure power is provided to required safety systems during a design basis event. The proposed change will not allow continuous operation such that a single failure will preclude the diesel generators from mitigating the consequences of design basis accidents or transients. The allowance provided for testing is only applicable for a limited time (2 hours) provided the associated Function maintains initiation capability for 2 diesel generators and associated 4.16 kV ESF buses. Since only 2 of the 3 diesel generators are necessary to start and 2 of the 3 4.16 kV ESF buses are required to be energized to mitigate the consequences of a design basis event, the consequences of an event occurring during the 2 hour time period are the same as an event occurring during the Completion Time of the current ACTIONS. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

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

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

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

   The proposed change will allow entry into the Conditions and Required Actions for a LOP instrument channel made inoperable for the performance of Surveillances to be delayed for 2 hours. This change does not involve a significant reduction in a margin of safety since the allowance is only applicable for a short period of time (2 hours) provided initiation capability of 2 diesel generators and associated 4.16 kV ESF buses is maintained from the associated Function. In addition, the change does not affect current analysis assumptions. Therefore, this change does not involve a significant reduction in a margin of safety.

L.1 CHANGE

Not used.

B

L.10 CHANGE

Not used.

B

NO SIGNIFICANT HAZARDS EVALUATION
ITS: 3.6.3.2 - PRIMARY CONTAINMENT ATMOSPHERE MIXING SYSTEM

There were no plant specific less restrictive changes identified for this Specification.

NO SIGNIFICANT HAZARDS EVALUATION
ITS: 3.9.1 - REFUELING EQUIPMENT INTERLOCKS

L.1 CHANGE

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

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

   The proposed change removes an unnecessary additional performance of a Surveillance which has been performed within its normally required Frequency. Not performing the Surveillance will not affect any equipment which is assumed as an initiator of any analyzed event. Furthermore, since the Surveillance continues to be performed on its normal Frequency, there is no impact on the capability of the system to perform its required safety function. Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

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

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

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

   The normal Surveillance Frequency has been shown, based on operating experience, to be adequate for assuring the equipment is available and capable of performing its intended function. Additionally, the requirements of SR 3.0.1 (current Specifications 4.0.1 and 4.0.3) provide assurance the equipment is OPERABLE prior to beginning the functions for which it is required. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

L.3 CHANGE

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

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

   The proposed change would remove an unnecessary additional performance of a Surveillance which has been performed within its normally required Frequency. Not performing the Surveillance would not affect any equipment which is assumed to be an initiator of any analyzed event. Further, since the Surveillance continues to be performed on its normal Frequency, there is no impact on the capability of the system to perform its required safety function. Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

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

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

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

   The normal Surveillance Frequency has been shown, based on operating experience, to be adequate for assuring the equipment is available and capable of performing its intended function. Additionally, the requirements of SR 3.0.1 (current Specifications 4.0.1 and 4.0.3) provide assurance the equipment is OPERABLE prior to beginning the functions for which it is required. Therefore, the proposed change does not involve a significant reduction in a margin of safety. (B)

L.4 CHANGE

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

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

   The proposed change would allow entry into and operation in the applicable conditions prior to completion of the required Surveillance. The refuel position one-rod-out interlock is not assumed to be an initiator of any analyzed event. The role of this interlock is to ensure that no more than one control rod be withdrawn, which prevents criticality, thereby limiting consequences. The change does not delete the Surveillance but postpones it until conditions necessary to perform the test (withdrawal of a control rod) are achieved. The time period is acceptably short taking into consideration the small probability of an event when the OPERABILITY of the interlock has not been demonstrated. It also acknowledges that the most probable result of the Surveillance performance is the verification of OPERABILITY. The consequences of any analyzed events are unaffected since the change does not alter any system or component design assumption or operation. Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated. (B)

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

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

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

   The proposed change allows sufficient time to achieve the condition necessary to perform the test (withdrawal of a control rod). Sufficient procedural controls are provided for control rod withdrawal to prevent inadvertent criticality. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

L.2 CHANGE

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

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

   The proposed change would remove an unnecessary additional performance of a Surveillance which has been performed within its normally required Frequency. Not performing the Surveillance would not affect any equipment which is assumed to be an initiator of any analyzed event. Further, since the Surveillance continues to be performed on its normal Frequency, there is no impact on the capability of the system to perform its required safety function. Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

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

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

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

   The normal Surveillance Frequency has been shown, based on operating experience, to be adequate for assuring the equipment is available and capable of performing its intended function. Additionally, the requirements of SR 3.0.1 (current Specifications 4.0.1 and 4.0.3) provide assurance the equipment is OPERABLE prior to beginning the functions for which it is required. Therefore, the proposed change does not involve a significant reduction in a margin of safety. (B)

NO SIGNIFICANT HAZARDS EVALUATION
ITS: 3.9.6 - RPV WATER LEVEL – IRRADIATED FUEL

L.1 CHANGE

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

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

   The proposed change will remove an unnecessary additional performance of a Surveillance which has been performed within its normally required Frequency. Not performing the Surveillance will not affect any equipment which is assumed to be an initiator of any analyzed event. Further, since the Surveillance continues to be performed on its normal Frequency, there is no impact on the capability of the water above the RPV flange to perform its required safety function. Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

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

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

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

   The normal Surveillance Frequency has been shown, based on operating experience, to be adequate for assuring the proper RPV water level is available and capable of performing its intended function. Additionally, the requirements of SR 3.0.1 (current Specifications 4.0.1 and 4.0.3) provide assurance the RPV water level is within limits prior to beginning the functions for which it is required. Therefore, the proposed change does not involve a significant reduction in a margin of safety. (B)

L.2 CHANGE

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

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

   The proposed change will remove an unnecessary additional performance of a Surveillance which has been performed within its normally required Frequency. Not performing the Surveillance will not affect any equipment which is assumed to be an initiator of any analyzed event. Further, since the Surveillance continues to be performed on its normal Frequency, there is no impact on the capability of the water in the RPV to perform its required safety function. Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

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

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

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

   The normal Surveillance Frequency has been shown, based on operating experience, to be adequate for assuring the proper RPV water level is available and capable of performing its intended function. Additionally, the requirements of SR 3.0.1 (current Specifications 4.0.1 and 4.0.3) provide assurance the RPV water level is within limits prior to beginning the functions for which it is required. Therefore, the proposed change does not involve a significant reduction in a margin of safety. (B)

NO SIGNIFICANT HAZARDS EVALUATION
ITS: 3.10.8 - SDM TEST – REFUELING

L.1 CHANGE

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

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

   The change does not result in any hardware or operating procedure changes. The proposed LCO requirements are not assumed to be initiators of any analyzed event. The role of these requirements is in mitigating a control rod drop accident, thereby limiting consequences of such an event. The proposed change still provides assurance the necessary equipment is OPERABLE and other controls of the LCO are met. Therefore, no significant increase in the probability or consequences of an accident previously evaluated is involved.

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

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

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

   The proposed change does not involve a significant reduction in a margin of safety since the 12 hour Frequency and the Frequencies specified in the applicable Surveillance Requirements have been shown to be adequate for assuring the necessary equipment OPERABILITY and other controls of the LCO are met. Additionally, the requirements of proposed SR 3.0.1 (current Specifications 4.0.1 and 4.0.3) provide assurance the requirements are met prior to the start of testing. (B)

NO SIGNIFICANT HAZARDS EVALUATION
CTS: 3/4.10.5 - OXYGEN CONCENTRATION

(B)

There were no plant specific less restrictive changes identified for this Specification.

NO SIGNIFICANT HAZARDS EVALUATION
CTS: 3/4.10.6 - TRAINING STARTUPS

1 (B)

There were no plant specific less restrictive changes identified for this Specification.

1.1 Definitions

CHANNEL CHECK (continued)	status derived from independent instrument channels measuring the same parameter.
CHANNEL FUNCTIONAL TEST	A CHANNEL FUNCTIONAL TEST shall be the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify OPERABILITY, including required alarm, interlock, display, and trip functions, and channel failure trips. The CHANNEL FUNCTIONAL TEST may be performed by means of any series of sequential, overlapping, or total channel steps so that the entire channel is tested.
CORE ALTERATION	CORE ALTERATION shall be the movement of any fuel, sources, or reactivity control components within the reactor vessel with the vessel head removed and fuel in the vessel. The following exceptions are not considered to be CORE ALTERATIONS: a. Movement of source range monitors, local power range monitors, intermediate range monitors, traversing incore probes, or special movable detectors (including undervessel replacement); b. Control rod movement, provided there are no fuel assemblies in the associated core cell. Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe position.
CORE OPERATING LIMITS REPORT (COLR)	The COLR is the unit specific document that provides cycle specific parameter limits for the current reload cycle. These cycle specific limits shall be determined for each reload cycle in accordance with Specification 5.6.5. Plant operation within these limits is addressed in individual Specifications.
DOSE EQUIVALENT I-131	DOSE EQUIVALENT I-131 shall be that concentration of I-131 (microcuries/gram) that alone would produce the same thyroid dose as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. The thyroid dose

TSTF-03 Changes not shown

(continued)

1.1 Definitions

<TSTF-03 changes not shown>

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

(continued)

1.1 Definitions

ISOLATION SYSTEM RESPONSE TIME (continued)	INSTRUMENTATION 5 delays, where applicable. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured.
L_a	The maximum allowable primary containment leakage rate, L_a, shall be [..]% of primary containment air weight per day at the calculated peak containment pressure (P_a). 10 B
LEAKAGE	LEAKAGE shall be: a. Identified LEAKAGE 1. LEAKAGE into the drywell such as that from pump seals or valve packing, that is captured and conducted to a sump or collecting tank; or 2. LEAKAGE into the drywell atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary LEAKAGE; b. Unidentified LEAKAGE All LEAKAGE into the drywell that is not identified LEAKAGE; c. Total LEAKAGE Sum of the identified and unidentified LEAKAGE; and 2 d. Pressure Boundary LEAKAGE LEAKAGE through a nonisolable fault in a Reactor Coolant System (RCS) component body, pipe wall, or vessel wall.
[LINEAR HEAT GENERATION RATE (LHGR)]	The LHGR shall be the heat generation rate per unit length of fuel rod. It is the integral of the heat flux over the heat transfer area associated with the unit length. [1

(continued)

1.1 Definitions (continued)

LOGIC SYSTEM FUNCTIONAL TEST	A LOGIC SYSTEM FUNCTIONAL TEST shall be a test of all required logic components (i.e., all required relays and contacts, trip units, solid state logic elements, etc.) of a logic circuit, from as close to the sensor as practicable up to, but not including, the actuated device, to verify OPERABILITY. The LOGIC SYSTEM FUNCTIONAL TEST may be performed by means of any series of sequential, overlapping, or total system steps so that the entire logic system is tested.
MAXIMUM FRACTION OF LIMITING POWER DENSITY (MFLPD)	The MFLPD shall be the largest value of the fraction of limiting power density in the core. The ~~fraction of limiting power density~~ shall be the LHGR existing at a given location divided by the specified LHGR limit for that bundle type.
MINIMUM CRITICAL POWER RATIO (MCPR)	The MCPR shall be the smallest critical power ratio (CPR) that exists in the core for each class of fuel. The CPR is that power in the assembly that is calculated by application of the appropriate correlation(s) to cause some point in the assembly to experience boiling transition, divided by the actual assembly operating power.
MODE	A MODE shall correspond to any one inclusive combination of mode switch position, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.
OPERABLE—OPERABILITY	A system, subsystem, division, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, division, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).

(continued)

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
CHAPTER 1.0 - USE AND APPLICATION

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

2. Typographical/grammatical error corrected.

3. The correct plant specific nomenclature has been provided.

4. This optional allowance has been deleted. WNP-2 measures the breaker arc suppression time.

5. The ISOLATION SYSTEM RESPONSE TIME definition has been modified to only include the instrumentation portion of the response time. The isolation valve portion of the response time (i.e., valve stroke times) does not need to be included since it is redundant to the valve stroke time requirements specified in ASME Section XI, which is required by NUREG Specification 5.5.7 (proposed Specification 5.5.6), the IST Program. In addition, specific Surveillance Requirements in LCO 3.6.1.3, Primary Containment Isolation Valves, also require the valve stroke times to be verified. The requirement to include diesel generator starting and loading times has been deleted since they are redundant to the diesel generator Surveillance Requirements in LCO 3.8.1, AC Sources—Operating. This deletion was recommended in both NUREG-1366 and Generic Letter 93-05. Due to these changes, the definition has been renamed to be ISOLATION INSTRUMENTATION RESPONSE TIME.

6. An acronym has been provided for fraction of limiting power density (FLPD), consistent with the acronym provided in the applicable LCO (LCO 3.2.4).

7. Generic change TSTF-03 has not been adopted. WNP-2 is evaluating this change and will decide whether or not to incorporate this change at a later date.

8. The appropriate LCO number has been provided.

9. The currently licensed manner in which TURBINE BYPASS SYSTEM RESPONSE TIME testing is performed has been provided.

10. A Primary Containment Leakage Rate Testing Program has been added to Section 5.5, consistent with the letter from C. I. Grimes to D. J. Modeen, dated November 2, 1995. This letter transmitted the draft ITS pages marked up to reflect Appendix J, Option B testing requirements. The Program includes the definition of L_a, therefore the definition in Section 1.1 is not needed.

2.0 SAFETY LIMITS (SLs)

2.1 SLs

2.1.1 Reactor Core SLs

2.1.1.1 With the reactor steam dome pressure < 785 psig or core flow < 10% rated core flow:

THERMAL POWER shall be ≤ 25% RTP.

2.1.1.2 With the reactor steam dome pressure ≥ 785 psig and core flow ≥ 10% rated core flow:

(1) MCPR shall be ≥ {1.07} for two recirculation loop operation or ≥ {1.08} for single recirculation loop operation.

2.1.1.3 Reactor vessel water level shall be greater than the top of active irradiated fuel.

2.1.2 Reactor Coolant System Pressure SL

Reactor steam dome pressure shall be ≤ 1325 psig.

2.2 SL Violations

With any SL violation, the following actions shall be completed: within 2 hours

2.2.1 Within 1 hour, notify the NRC Operations Center, in accordance with 10 CFR 50.72.

2.2.2 Within 2 hours:

2.2.2.1 Restore compliance with all SLs; and

2.2.2.2 Insert all insertable control rods.

2.2.3 Within 24 hours, notify the [General Manager—Nuclear Plant and Vice President—Nuclear Operations].

TSTF-05

B

(continued)

2.0 SLs

2.2 SL Violations (continued)

TSTF-05

2.2.4 Within 30 days, a Licensee Event Report (LER) shall be prepared pursuant to 10 CFR 50.73. The LER shall be submitted to the NRC and the [General Manager–Nuclear Plant and Vice President–Nuclear Operations].

B

2.2.5 Operation of the unit shall not be resumed until authorized by the NRC.

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

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

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Two or more control rod scram accumulators inoperable with reactor steam dome pressure ≥ {900} psig. (1)	B.1 Restore charging water header pressure to ≥ {1520} psig. (940) (1)	20 minutes from discovery of Condition B concurrent with charging water header pressure < {1520} psig (940) (1)
	AND	
	B.2.1 --------NOTE--------- Only applicable if the associated control rod ~~scram time was~~ within the limits of Table 3.1.4-1 during the last scram time Surveillance. --------- (4)	the average scram times of the two-by-two arrays with the (4)
	Declare the associated control rod scram time "slow."	1 hour
	OR	
	B.2.2 Declare the associated control rod inoperable.	1 hour
C. One or more control rod scram accumulators inoperable with reactor steam dome pressure < {900} psig. (1)	C.1 (5) Verify ~~all~~ the control rods associated with ~~inoperable~~ accumulators are is fully inserted.	Immediately upon discovery of charging water header pressure < {1520} psig (940) (1) (B)
	AND	

Declare the average scram time in all two-by-two arrays associated with the control rod with the inoperable accumulator not within the limits of Table 3.1.4-1 and declare the associated control rod "slow."

with the inoperable accumulator are (4)

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
SR 3.3.1.1.9 Perform CHANNEL FUNCTIONAL TEST.	7 days
SR 3.3.1.1.8 Verify the source range monitor (SRM) and intermediate range monitor (IRM) channels overlap.	Prior to withdrawing SRMs from the fully inserted position
SR 3.3.1.1.10 NOTE: Only required to be met during entry into MODE 2 from MODE 1. Verify the IRM and APRM channels overlap.	7 days
SR 3.3.1.1.9 Calibrate the local power range monitors.	~~1000~~ 1130 MWD/T average core exposure
SR 3.3.1.1.10 Perform CHANNEL FUNCTIONAL TEST.	~~92~~ days
SR 3.3.1.1.10 Calibrate the trip units.	[92] days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
SR 3.3.3.2.1 Verify each required control circuit and transfer switch is capable of performing the intended functions.	~~18~~ 24 months
SR 3.3.3.2.2 Perform CHANNEL CALIBRATION for each required instrumentation channel, except the suppression pool water level instrumentation channel.	18 months
SR 3.3.3.2.3 Perform CHANNEL CALIBRATION for the suppression pool water level instrumentation channel.	24 months

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.5.1-1 to determine which SRs apply for each ECCS Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed as follows: (a) for up to 6 hours for Functions 3.c, 3.f, 3.g and 4.b; and (b) for up to 6 hours for Functions other than 3.c, 3.f, 3.g and 4.b, provided the associated Function or the redundant Function maintains ECCS initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.5.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.5.1.2	Perform CHANNEL FUNCTIONAL TEST.	~~92~~ days
SR 3.3.5.1.3	Calibrate the trip unit.	[92] days
SR 3.3.5.1.~~8~~	Perform CHANNEL CALIBRATION.	92 days
SR 3.3.5.1.~~9~~	Perform CHANNEL CALIBRATION.	~~18~~ months
SR 3.3.5.1.6	Perform LOGIC SYSTEM FUNCTIONAL TEST.	~~18~~ 24 months
SR 3.3.5.1.7	Verify the ECCS RESPONSE TIME is within limits.	[18] months on a STAGGERED TEST BASIS
SR 3.3.5.1.5	Perform CHANNEL CALIBRATION	24 months

Table 3.3.5.1-1 (page 1 of 5)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Low Pressure Coolant Injection-A (LPCI) and Low Pressure Core Spray (LPCS) Subsystems					
a. Reactor Vessel Water Level – Low Low Low, Level 1	1,2,3, 4(a), 5(a)	X (b)	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.5 SR 3.3.5.1.6 SR 3.3.5.1.7	≥ X inches
b. Drywell Pressure – High	1,2,3	X (b)	B	SR 3.3.5.1.2 SR 3.3.5.1.5 SR 3.3.5.1.6 SR 3.3.5.1.7	≤ X psig
c. LPCI Pump A Start – Time Delay Relay	1,2,3, 4(a), 5(a)	1	C	SR 3.3.5.1.4 SR 3.3.5.1.6	≥ X seconds and ≤ X seconds
d. Reactor Steam Dome Pressure – Low (Injection Permissive)	1,2,3	1 per valve	C	SR 3.3.5.1.2 SR 3.3.5.1.5 SR 3.3.5.1.6 SR 3.3.5.1.7	≥ X psig and ≤ X psig
	4(a), 5(a)	3	B	SR 3.3.5.1.2 SR 3.3.5.1.5 SR 3.3.5.1.6 SR 3.3.5.1.7	≥ X psig and ≤ X psig
e. LPCS Pump Discharge Flow – Low (Bypass) (Minimum Flow)	1,2,3, 4(a), 5(a)	1	E	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5 SR 3.3.5.1.6	≥ [ ] gpm and ≤ [ ] gpm
f. LPCI Pump A Discharge Flow – Low (Bypass)	1,2,3, 4(a), 5(a)	1	E	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5 SR 3.3.5.1.6	≥ X gpm and ≤ X gpm
g. Manual Initiation	1,2,3, 4(a), 5(a)	2	C	SR 3.3.5.1.6	NA

(continued)

(a) When associated subsystem(s) are required to be OPERABLE.

(b) Also required to initiate the associated Technical Specifications (TS) required functions diesel generator (DG).

(24)

INSERT 1.c and 1.d

c.	LPCS Pump Start-LOCA Time Delay Relay	1,2,3, 4(a),5(a)	1	C	SR 3.3.5.1.5 SR 3.3.5.1.6	≥ 8.53 seconds and ≤ 10.64 seconds (A)
d.	LPCI Pump A Start-LOCA Time Delay Relay	1,2,3, 4(a),5(a)	1	C	SR 3.3.5.1.5 SR 3.3.5.1.6	≥ 17.24 seconds and ≤ 21.53 seconds (B)

(B)

Table 3.3.5.1-1 (page 2 of 5)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. LPCI B and LPCI C Subsystems					
a. Reactor Vessel Water Level – Low Low Low, Level 1	1,2,3, 4(a),5(a)	2	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5 SR 3.3.5.1.6 SR 3.3.5.2.1	≥ -148 inches
b. Drywell Pressure – High	1,2,3	2	B	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5 SR 3.3.5.1.6 SR 3.3.5.2.1	≤ 1.88 psig
c. LPCI Pump B Start – Time Delay Relay	1,2,3, 4(a),5(a)	2	C	SR 3.3.5.1.2 SR 3.3.5.1.5 SR 3.3.5.1.6	≥ 3.04 seconds and ≤ 6.00 seconds
d. Reactor Steam Dome Pressure – Low (Injection Permissive)	1,2,3	1 per valve	C	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5 SR 3.3.5.1.6 SR 3.3.5.2.1	≥ 498 psig and ≤ 492 psig
	4(a),5(a)	2	B	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5 SR 3.3.5.1.6 SR 3.3.5.2.1	≥ 492 psig and ≤ psig
e. LPCI Pump B and LPCI Pump C Discharge Flow – Low (Minimum Flow)	1,2,3, 4(a),5(a)	1 per pump	E	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5 SR 3.3.5.1.6 SR 3.3.5.2.1	≥ 605 gpm and ≤ 984 gpm
f. Manual Initiation	1,2,3, 4(a),5(a)	2	C	SR 3.3.5.1.6	NA

(continued)

(a) When associated subsystem(s) are required to be OPERABLE.

(b) Also required to initiate the associated ADS required functions.

(24)

INSERT 2.c and 2.d

c.	LPCI Pump B Start-LOCA Time Delay Relay	1,2,3, 4(a),5(a)	1	C	SR 3.3.5.1.5 SR 3.3.5.1.6	≥ 17.24 seconds and ≤ 21.53 seconds (B)
d.	LPCI Pump C Start-LOCA Time Delay Relay	1,2,3, 4(a),5(a)	1	C	SR 3.3.5.1.5 SR 3.3.5.1.6	≥ 8.53 seconds and ≤ 10.64 seconds (B)

Insert Page 3.3-42

A

Table 3.3.5.1-1 (page 3 of 5)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
3. High Pressure Core Spray (HPCS) System					
a. Reactor Vessel Water Level – Low Low, Level 2	1,2,3, 4(a),5(a)	4(b)	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5 SR 3.3.5.1.6 SR 3.3.5.1.7	≥ [redacted] inches
b. Drywell Pressure – High	1,2,3	4(b)	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5 SR 3.3.5.1.6 SR 3.3.5.1.7	≤ [redacted] psig
c. Reactor Vessel Water Level – High, Level 8	1,2,3, 4(a),5(a)	2	C	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5 SR 3.3.5.1.6	≤ [redacted] inches
d. Condensate Storage Tank Level – Low	1,2,3, 4(c),5(c)	2	D	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5 SR 3.3.5.1.6	≥ [redacted] inches
e. Suppression Pool Water Level – High	1,2,3	2	D	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5 SR 3.3.5.1.6	≤ [redacted] inches
f. [HPCS Pump Discharge Pressure – High (Bypass)]	1,2,3, 4(a),5(a)	[1]	E	SR 3.3.5.1.1 SR 3.3.5.1.2 [SR 3.3.5.1.3] SR 3.3.5.1.5 SR 3.3.5.1.6	≥ [ ] psig
g. XHPCS System Flow Rate – Low (Bypass)]	1,2,3, 4(a),5(a)	1	E	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5 SR 3.3.5.1.6	≥ [redacted] gpm and ≤ [redacted] gpm
h. Manual Initiation	1,2,3, 4(a),5(a)	2	C	SR 3.3.5.1.6	NA

(continued)

(a) When associated subsystem(s) are required to be OPERABLE.

(b) Also required to initiate the associated [TS required functions].

(c) When HPCS is OPERABLE for compliance with LCO 3.5.2, "ECCS – Shutdown," and aligned to the condensate storage tank while tank water level is not within the limit of SR 3.5.2.2.

Table 3.3.5.1-1 (page 4 of 5)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
4. Automatic Depressurization System (ADS) Trip System A					
a. Reactor Vessel Water Level – Low Low Low, Level 1	1,2(d),3(d)	X2X (2)	F	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5 SR 3.3.5.1.6	≥ X inches
b. Drywell Pressure – High	1,2(d),3(d)	[2]	F	SR 3.3.5.1.1 SR 3.3.5.1.2 [SR 3.3.5.1.3] SR 3.3.5.1.5 SR 3.3.5.1.6	≤ [1.44] psig
c. ADS Initiation Timer	1,2(d),3(d)	X1X	G	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≤ X seconds
d. Reactor Vessel Water Level – Low, Level 3 (Confirmatory)	1,2(d),3(d)	X1X (2)	F	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5 SR 3.3.5.1.6	≥ X inches
e. LPCS Pump Discharge Pressure – High	1,2(d),3(d)	X2X	G	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5 SR 3.3.5.1.6	≥ X psig and ≤ X psig
f. LPCI Pump A Discharge Pressure – High	1,2(d),3(d)	X2X (2)	G	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5 SR 3.3.5.1.6	≥ X psig and ≤ X psig
g. ADS Bypass Timer (High Drywell Pressure)]	1,2(d),3(d)	[2]	G	SR 3.3.5.1.2 [SR 3.3.5.1.4] SR 3.3.5.1.6	≤ [9.4] minutes
h. Manual Initiation	1,2(d),3(d)	X2X (4)	G	SR 3.3.5.1.6	NA
f. Accumulator Backup Compressed Gas System Pressure – Low	1,2(d),3(e)	3	F	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ 154 psig

(continued)

(d) With reactor steam dome pressure > X150X psig.
(2)

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Table 3.3.5.1-1 (page 5 of 5)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
5. ADS Trip System B					
a. Reactor Vessel Water Level – Low Low Low, Level 1	1,2(d),3(d)	[2]	F	SR 3.3.5.1.1 SR 3.3.5.1.2 [SR 3.3.5.1.3] SR 3.3.5.1.5 SR 3.3.5.1.6	≥ [-162] inches
b. Drywell Pressure – High	1,2(d),3(d)	[2]	F	SR 3.3.5.1.1 SR 3.3.5.1.2 [SR 3.3.5.1.3] SR 3.3.5.1.5 SR 3.3.5.1.6	≤ [1.44] psig
c. ADS Initiation Timer	1,2(d),3(d)	[1]	G	SR 3.3.5.1.2 [SR 3.3.5.1.3] SR 3.3.5.1.6	≤ [120] seconds
d. Reactor Vessel Water Level – Low, Level 3 (Confirmatory)	1,2(d),3(d)	[2]	F	SR 3.3.5.1.1 SR 3.3.5.1.2 [SR 3.3.5.1.3] SR 3.3.5.1.5 SR 3.3.5.1.6	≥ [108] inches
e. LPCI Pump B & C Discharge Pressure – High (Permissive)	1,2(d),3(d)	[1] per pump	G	SR 3.3.5.1.2 SR 3.3.5.1.2 [SR 3.3.5.1.3] SR 3.3.5.1.5 SR 3.3.5.1.6	≥ [116] psig and ≤ [134] psig
f. [ADS bypass timer (High Drywell Pressure)]	1,2(d),3(d)	[2]	G	SR 3.3.5.1.2 [SR 3.3.5.1.4] SR 3.3.5.1.6	≤ [9.4] minutes
g. Manual Initiation	1,2(d),3(d)	[2]	G	SR 3.3.5.1.6	NA
e. Accumulator Backup Compressed Gas System Pressure – Low	1,2(d),3(d)	3	F	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.6	≥ 154 psig

(d) With reactor steam dome pressure > [150] psig.

Table 3.3.6.1-1 (page 1 of 6)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Main Steam Line Isolation					
a. Reactor Vessel Water Level – Low Low (20), Level 2	1,2,3	X2X	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6 SR 3.3.6.1.6 SR 3.3.6.1.7	≥ X-52.7X inches
b. Main Steam Line Pressure – Low	1	X2X	E	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.6 SR 3.3.6.1.7	≥ [837] psig
c. Main Steam Line Flow – High	1,2,3	X2X per MSL	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.6 SR 3.3.6.1.7	≤ Y76.5 psig
d. Condenser Vacuum – Low	1,2(a), 3(a)	X2X	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.6	≥ X6.X inches Hg vacuum
e. Main Steam Tunnel Temperature – High	1,2,3	[81]	D	SR 3.3.6.1.1 SR 3.3.6.1.5 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ [191]°F
f. Main Steam Tunnel Differential Temperature – High	1,2,3	X2X	D	SR 3.3.6.1.1 SR 3.3.6.1.6 SR 3.3.6.1.6 SR 3.3.6.1.6	≤ [110]°F
g. Manual Initiation	1,2,3	[2]	G	SR 3.3.6.1.6	NA
2. Primary Containment Isolation					
a. Reactor Vessel Water Level – Low Low, Level 2	1,2,3	X2X	H	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.6 SR 3.3.6.1.7	≥ X-52.7X inches

(continued)

(a) With any turbine throttle valve not closed.

a. Reactor Vessel Water Level-Low, Level 3 | 1,2,3 | 2 | F | SR 3.3.6.1.1
SR 3.3.6.1.2
SR 3.3.6.1.4
SR 3.3.6.1.6 | ≥ 9.5 inches

Table 3.3.6.1-1 (page 6 of 6)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
5. Shutdown Cooling System Isolation					
a. RHR Equipment Room Temperature – High	3	1 per room (d)	F	SR 3.3.6.1.3 SR 3.3.6.1.4 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 150°F
b. RHR Equipment Room Differential Temperature – High	3	1 per room (d)	F	SR 3.3.6.1.3 SR 3.3.6.1.4 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 70°F
c. Reactor Vessel Water Level – Low, Level 3	3,4,5	2 (d)(e)	J	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 9.5 inches
d. Reactor Vessel Shell Pressure – High	1,2,3	2 1 (d)	F	SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 135 psig
e. Drywell Pressure – High	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 [SR 3.3.6.1.3] SR 3.3.6.1.5 SR 3.3.6.1.6	≤ [1.43] psig
f. Manual Initiation	1,2,3	2 (d)	G	SR 3.3.6.1.6	NA
c. Heat Exchangers Area Temperature – High	3	1 per room (d)	F	SR 3.3.6.1.3 SR 3.3.6.1.4 SR 3.3.6.1.6	
Room 505 Area					≤ 140°F
Room 507 Area					≤ 160°F
Room 605 Area					≤ 150°F
Room 606 Area					≤ 140°F

(a) Only one trip system required in MODES 4 and 5 with RHR Shutdown Cooling System integrity maintained.

(d) Only the inboard trip system required in MODES 1, 2, and 3, as applicable, when the outboard valve control is transferred to the alternate remote shutdown panel and the outboard valve is closed.

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.8.1-1 to determine which SRs apply for each LOP Function..

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 2 hours provided the associated Function maintains ~~OR~~ initiation capability.

SURVEILLANCE	FREQUENCY
SR ~~3.3.8.1.1~~ Perform ~~CHANNEL CHECK.~~	12 hours
SR 3.3.8.1.~~0~~ Perform CHANNEL FUNCTIONAL TEST.	31 days
SR 3.3.8.1.~~0~~ Perform CHANNEL CALIBRATION.	~~18~~ months
SR 3.3.8.1.4. Perform LOGIC SYSTEM FUNCTIONAL TEST.	~~18~~ months
SR 3.3.8.1.3 Perform CHANNEL CALIBRATION	24 months

Table 3.3.8.1-1 (page 1 of 1)
Loss of Power Instrumentation

FUNCTION	REQUIRED CHANNELS PER DIVISION	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Divisions 1 and 2 – 4.16 kV Emergency Bus Undervoltage			
a. Loss of Voltage – 4.16 kV Basis		SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 2450 V and ≤ 3135 V
b. Loss of Voltage – Time Delay		SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 2.65 seconds and ≤ 5.9 seconds
c. Degraded Voltage – 4.16 kV Basis		SR 3.3.8.1.1 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ [illegible] V and ≤ [illegible] V
d. Degraded Voltage – Time Delay		SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 3685 seconds and ≤ 3755 seconds
2. Division 3 – 4.16 kV Emergency Bus Undervoltage			
a. Loss of Voltage – 4.16 kV Basis		SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 2450 V and ≤ 3135 V
b. Loss of Voltage – Time Delay		SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 1.2 seconds and ≤ [illegible] seconds
c. Degraded Voltage – 4.16 kV Basis		SR 3.3.8.1.1 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ [illegible] V and ≤ [illegible] V
d. Degraded Voltage – Time Delay		SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 7.36 seconds and ≤ 8.34 seconds
e. Degraded Voltage – Time Delay, LOCA	[4]	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ [3.6] seconds and ≤ 4.4 seconds.

(a) The Degraded Voltage – 4.16 kV Basis and – Primary Time Delay Functions must be associated with one another.

(b) The Loss of Voltage – 4.16 kV Basis and · — Time Delay Functions must be in the same trip system.

g. Degraded Voltage – Secondary Time Delay	1	SR 3.3.8.1.2 SR 3.3.8.1.3	≥ 2.63 seconds and ≤ 3.39 seconds
c. TR-B Loss of Voltage – 4.16 kV Basis	1	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 2450 V and ≤ 3135 V
d. TR-B Loss of Voltage – Time Delay	1	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 3.00 seconds and ≤ 6.00 seconds

3.3 INSTRUMENTATION

3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

LCO 3.3.8.2 Two RPS electric power monitoring assemblies shall be OPERABLE for each inservice RPS motor generator set or alternate power supply that supports equipment required to be OPERABLE or with both residual heat removal (RHR) shutdown cooling (SDC) suction isolation valves open.

APPLICABILITY: MODES 1, 2, and 3,
MODES 4 and 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies MODE 5

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or both required inservice power supplies with one electric power monitoring assembly inoperable.	A.1 Remove associated inservice power supply(s) from service.	72 hours.
B. One or both required inservice power supplies with both electric power monitoring assemblies inoperable.	B.1 Remove associated inservice power supply(s) from service.	1 hour
C. Required Action and associated Completion Time of Condition A or B not met in MODE 1, 2, or 3.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A or B not met in MODE 4 or 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.	B.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately
D. Required Action and associated Completion Time of Condition A or B not met in MODE 4 or 5 with both RHR SDC suction isolation valves open.	D.1 Initiate action to restore one electric power monitoring assembly to OPERABLE status for inservice power supply(s) supplying required instrumentation.	Immediately
	OR	
	D.2 Initiate action to isolate the ~~Residual Heat Removal Shutdown Cooling~~ RHR SDC System.	Immediately

<20> <INSERT SR NOTE>

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.8.2.1	----------NOTE---------- Only required to be performed prior to entering MODE 2 or 3 from MODE 4, when in MODE 4 for ≥ 24 hours. ----------	
	Perform CHANNEL FUNCTIONAL TEST.	184 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
SR 3.3.8.2.2 Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. Overvoltage, with time delay set to zero; Bus A ≤ [132.9] V Bus B ≤ [133.01] V b. Undervoltage, with time delay set to zero; and Bus A ≥ [110.8] V Bus B ≥ [115.91] V c. Underfrequency, with time delay set to [zero] Bus A ≥ [57] Hz Bus B ≥ [57.1] Hz	[18] months
SR 3.3.8.2.[4] Perform a system functional test.	[18] months

Insert SR 3.3.8.2.3

12. (continued)

and f) the Loss of Power Instrumentation Functions, has been deleted since the current WNP-2 design does not include indication to perform a CHANNEL CHECK. The following Surveillances have been renumbered, where applicable, to reflect this deletion.

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

14. The BWR/6 LCO 3.3.2.1 has been deleted and, in its place, the BWR/4 LCO 3.3.2.1 (from NUREG-1433) has been used since the WNP-2 design is similar to the BWR/4 design with regards to the control rod block instrumentation. Any deviations from the BWR/4 ITS are discussed.

15. A new Specification has been added, proposed LCO 3.3.2.2. This Specification is from the BWR/4 ITS (NUREG-1433), since the WNP-2 design is similar to the BWR/4 design with regards to the feedwater and main turbine high water level trip instrumentation. Therefore, the BWR/4 LCO is used and any deviations from the BWR/4 ITS are discussed.

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

17. The proper Specification number has been provided.

18. ACTION D and the Note in Condition C has been deleted. These current requirements specify a 72 hour Completion Time to restore one hydrogen monitor to OPERABLE status when two hydrogen monitors are inoperable. This change will allow a 7 day Completion Time to restore one hydrogen monitor when both are inoperable, as shown in ACTION C. There is no difference, with respect to their importance during an accident, between the H_2 and O_2 monitors and other PAM instrumentation. The H_2 and O_2 monitors are located outside the primary containment, similar to most other PAM Functions. The function of the H_2 and O_2 monitors is to determine H_2 and O_2 concentrations to ensure the H_2 recombiners are operated in sufficient time following an accident to limit H_2 and O_2 concentrations below the flammability limits. If the H_2 and O_2 monitors are inoperable, the H_2 recombiners can be operated immediately following an accident; there is no negative effect of turning on the H_2 recombiners too soon following an accident. The Post Accident Sampling System (PASS), which is independent to the monitors, can be used to sample the primary containment to determine H_2 and O_2 concentrations. The monitors can also be used to determine an approximation of core damge during a severe accident. However, the PASS would normally be used during a severe accident to determine the amount of fuel damage (the monitors are simply a backup to the PASS, and do not provide as detailed information as the PASS does). In addition, the requirements have been renumbered, where applicable, to reflect this deletion. (B)

19. Since there is one PAM Function that specifies more than two channels, Condition C and Required Action C.1 has been modified to reflect this requirement.

20. A Note has been added to the Surveillance Requirements (Note 2 for LCO 3.3.3.1, the Note for LCO 3.3.3.2, and the Note for LCO 3.3.8.2) to allow a channel to be inoperable for up to 6 hours solely for performance of required Surveillances provided the other channel(s) in the associated Function are OPERABLE. The 6 hour testing allowance has been granted by the NRC in Technical Specification amendments for Georgia Power Company's Hatch Unit 1 (amendment 185) and Unit 2 (amendment 125). The NRC has also granted this allowance in other topical reports for the RPS, ECCS, and isolation instrumentation. In addition, the current Note to the Surveillance Requirements for LCO 3.3.3.1 has been numbered "1" to reflect this addition.

21. This Reviewer's Note has been deleted and the appropriate instruments have been added to the Table, consistent with the Note. The Note is not meant to be retained in the final version of the plant specific submittal. In addition, the Functions have been renumbered, where applicable, to reflect the additions and deletions.

22. The Remote Shutdown System Table (Table 3.3.3.2-1) has been relocated to other plant controlled documents (the Licensee Controlled Specifications Manual). this change is consistent with the provisions of Generic Letter 91-08 for the removal of lists and has been recently approved for Clinton Power Station (amendment 68) on that basis.

23. The design of the EOC-RPT System and the applicable safety analysis is such that EOC-RPT is assumed at all times when THERMAL POWER is $\geq$ 30% RTP, not just when the recirculation pumps are in fast speed. Therefore, the Applicability has been modified to reflect this design and analysis assumption. In addition, Required Action C.1 has also been modified to delete the reference to the fast speed breaker.

24. Six new ECCS Functions have been added. Functions 1.c, 1.d, 2.c, and 2.d are time delay relays that delay starting of the low pressure ECCS pumps following a LOCA with offsite power available. These Functions are similar to those Functions in the NUREG that delay starting ECCS pumps following a LOCA with offsite power not available (current Functions 1.c and 2.c, proposed Functions 1.e and 2.e). Functions 4.f and 5.e are ADS Accumulator Backup Compressed Gas System Pressure-Low Functions that automatically align a safety-related air supply to the ADS valves. Appropriate ACTIONS and SRs have also been added. In addition, the Functions and SRs have been renumbered, where applicable, to reflect these additions. (B)

25. The current WNP-2 design does not include the HPCS Pump Discharge Pressure-High (Bypass), ADS Drywell Pressure-High, and ADS Bypass Timer (High Drywell Pressure) Functions (current NUREG Functions 3.f, 4.b, 4.g, 5.b, and 5.f). Therefore, these Functions have been deleted and the remaining Functions have been renumbered, where applicable, to reflect these deletions.

26. The CHANNEL FUNCTIONAL TEST (CFT) for proposed Functions 1.e, 2.e, 4.b, and 5.b (current NUREG Functions 1.c, 2.c, 4.c, and 5.c) is being deleted because a CHANNEL CALIBRATION is performed on these Functions at the same Frequency, and the definition of CHANNEL CALIBRATION encompasses the CFT.

27. The current WNP-2 design does not include the RCIC Suppression Pool Water Level–High Function (current NUREG Function 4). Therefore, this Function has been deleted and the remaining Function has been renumbered to reflect this deletion.

28. The proper Primary Containment Isolation Functions that are common to the RPS Instrumentation have been provided.

29. The Reactor Building Exhaust Plenum Radiation–High Function (proposed Function 2.d, current NUREG Function 2.g) is not currently required nor needed in MODES other than MODES 1, 2, and 3. Therefore, this requirement has been deleted. The associated ACTION (ACTION K) has also been deleted.

30. The proper CHANNEL CALIBRATION Frequency for the RWCU Differential Flow–Time Delay has been provided (24 months). Therefore, this Surveillance, which performs the CHANNEL CALIBRATION every 92 days, has been deleted.

31. This Reviewer's Note has been deleted and the appropriate Functions now include this SR requirement, consistent with the Note. The Note is not meant to be retained in the final version of the plant specific submittal. For the Secondary Containment Isolation Instrumentation Functions, there are no appropriate Functions. Therefore, the entire NUREG SR 3.3.6.2.6 has been deleted.

32. Six new Primary Containment Isolation Functions have been added (proposed Functions 2.a, 3.g, 4.b, 4.c, 5.c, and 5.f), consistent with current WNP-2 Licensing Basis. In addition, 14 Functions have been deleted (current NUREG Functions 2.c, 2.d, 2.e, 2.f, 3.g, 3.h, 3.i, 3.j, 3.k, 3.l, 3.m, 4.i, 4.j, and 5.e) since they are not applicable to WNP-2. The Functions have been renumbered, where applicable, to reflect these additions and deletions.

33. This Secondary Containment Isolation Instrumentation Function (current NUREG Function 4) has been deleted since it is not applicable to WNP-2. The following Function has been renumbered to reflect this deletion.

34. This Specification has been deleted since the WNP-2 RHR Drywell Spray System is manually actuated using the RHR System pump and valve controls.

35. This Specification has been deleted since the WNP-2 Suppression Pool Makeup is manually actuated.

36. The current WNP-2 Licensing Basis does not include Technical Specification requirements for the relief mode of the SRVs since the overpressure protection analysis does not assume the relief mode functions to mitigate an overpressurization event. The WNP-2 design does not include a LLS mode of the SRVs. Therefore, this Specification has been deleted.

37. Proposed ACTIONS E and F have been added (and current NUREG ACTION D deleted) to provide the proper requirements for the Main Control Room Ventilation radiation Monitor. This monitor does not provide an automatic start of the CREF System or isolation of the control room; it provides an alarm only to alert the operators to a high radiation condition at the remote air intakes. These ACTIONS are consistent with the current WNP-2 Licensing Basis, as modified by the changes annotated in the Discussion of Changes for ITS 3.3.7.1. Refer to Comments M.4, L.2, and L.3 of the Discussion of Changes for ITS 3.3.7.1 for further discussion. The other ACTIONS have been renumbered, where applicable, to reflect this change. In addition, Note 2 to the Surveillance Requirements has been modified and the LSFT requirement has been deleted to reflect this design.

38. The WNP-2 design of the CREF System does not include a toxic gas mode; therefore, this Note has been deleted.

39. The CREF System Reactor Building Vent Exhaust Plenum Radiation–High Function has been added (proposed Function 3) consistent with current WNP-2 Licensing Basis. The other Functions have been renumbered, where applicable, to reflect this change.

40. The current WNP-2 Licensing Basis only requires the CHANNEL FUNCTIONAL TEST (CFT) to be performed every 18 months as part of the CHANNEL CALIBRATION. Therefore, a specific CFT Surveillance Requirement has been deleted.

41. The LOP Instrumentation Divisions 1 and 2 Degraded Voltage–Secondary Time Delay Function has been added (proposed Function 1.e) consistent with current design. The LOP Instrumentation Division 3 Degraded Voltage–Time Delay, LOCA Function has been deleted (current NUREG Function 2.e) since the WNP-2 design does not include separate non-LOCA and LOCA time delays. In addition, footnotes (a) and (b) have been added consistent with the WNP-2 design. The LOP Instrumentation has also been modified by adding new Functions 1.c and 1.d. These Functions, placing requirements on the TR-B loss of voltage instrumentation, ensure that if TR-B (the alternate offsite circuit) is tied to the 4.16 kV ESF buses during a loss of voltage event, the associated breakers will be tripped to allow the DG to tie to the 4.16 kV ESF buses. These instruments are similar to the TR-S loss of voltage instrumentation currently in the WNP-2 TS. Appropriate ACTIONS and SRs have also been added. The SRs have been renumbered due to this addition. (B)

42. A new Note has been added to NUREG SR 3.3.1.2.5 to state that the determination of the signal to noise ratio is not required to be met with less than or equal to four fuel assemblies adjacent to the SRM and no other fuel in the associated core quadrant. When starting to load fuel from the defueled condition, SR 3.3.1.2.5 must be current prior to the start of fuel load. However, with no fuel in the core, a signal to noise ratio cannot be determined. Therefore, this Note has been added similar to the Note in the count rate Surveillance (SR 3.3.1.2.4), which is for the same reason as this proposed Note.

43. In MODES 4 and 5, the RPS Electric Power Monitoring assemblies (LCO 3.3.8.2) are required to support the instrumentation that provides an isolation signal to the RHR SDC suction isolation valves. The instrumentation is listed in LCO 3.3.6.1, and only one of the two trip systems is required when RHR SDC System integrity is maintained (ITS Note c to Table 3.3.6.1-1). This LCO requires two RPS Electric Power Monitoring assemblies to be OPERABLE for each inservice RPS power supply. However, only one RPS power supply is needed to support the required instrumentation, provided the RHR SDC System integrity is maintained. Currently, this LCO requires RPS Electric Power Monitoring assemblies to be OPERABLE on an inservice RPS power supply (which is normally maintained inservice at all times), even when no equipment is required to be OPERABLE. Therefore, the words "that support equipment required to be OPERABLE" have been added. This will allow the RPS Electric Power Monitoring assemblies on one of the two RPS power supplies to be inoperable when no required equipment is being powered from the associated RPS power supply. In addition, the word "required" has been added to Conditions A and B for consistency with the Writer's Guide, since, based on the above described change, all RPS Electric Power Monitoring assemblies may not be required OPERABLE at all times. (B)

44. The MODE 4 and 5 Applicability of LCO 3.3.8.2, "RPS Electric Power Monitoring," as it relates to control rod withdrawal, is revised to not include MODE 4, consistent with the Applicability of RPS Functions in LCO 3.3.1.1. In MODE 4, a control rod may be withdrawn from a core cell containing one or more fuel assemblies in accordance with LCO 3.10.4, "Single Control Rod Withdrawal—Cold Shutdown." Therefore, LCO 3.10.4 includes OPERABILITY requirements for RPS Functions and control rods (LCO 3.9.5). As a result, LCO 3.10.4 has been modified to also include requirements for the RPS Electric Power Monitoring assemblies to be OPERABLE when the RPS Functions and control rods are required to be OPERABLE (See Section 3.10, Justification for Deviations, comment 9). Commensurate changes to the ACTIONS of LCO 3.3.8.2 have also been made for consistency. The current ACTION D has been split into two separate ACTIONS, one for when the RHR SDC suction isolation valves are open and the other for when a control rod is withdrawn. This provides separate and discrete ACTIONS for the two separate Applicabilities (MODE 4 and 5 with both RHR SDC suction isolation valves open and MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies).

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition D not met. OR No recirculation loops in operation.	B.1 Be in MODE 3.	12 hours

in a Region other than Region A of the power-to-flow map

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	----------NOTE---------- Not required to be performed until 24 hours after both recirculation loops are in operation. ---------- Verify recirculation loop drive flow mismatch with both recirculation loops in operation is: a. ≤ {10}% of rated core flow when operating at < {70}% of rated core flow; and b. ≤ {5}% of rated core flow when operating at ≥ {70}% of rated core flow.	24 hours
SR 3.4.1.2	Verify operation is in the "unrestricted" Region of the power-to-flow map specified in the COLR.	24 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.B RCS Operational LEAKAGE

LCO 3.4.B RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE;

b. ≤ 5 gpm unidentified LEAKAGE; and

c. ≤ 25 gpm total LEAKAGE averaged over the previous 24 hour period; and

d. ≤ 2 gpm increase in unidentified LEAKAGE within the previous 24 hour period in MODE 1.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Unidentified LEAKAGE not within limit. OR Total LEAKAGE not within limit.	A.1 Reduce LEAKAGE to within limits.	4 hours
B. Unidentified LEAKAGE increase not within limit.	B.1 Reduce LEAKAGE to within limit. OR	4 hours (continued)

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.6 RCS Pressure Isolation Valve (PIV) Leakage

LCO 3.4.6 The leakage from each RCS PIV shall be within limit.

APPLICABILITY: MODES 1 and 2,
MODE 3, except valves in the residual heat removal (RHR) shutdown cooling flow path when in, or during the transition to or from, the shutdown cooling mode of operation.

ACTIONS

---NOTES---

1. Separate Condition entry is allowed for each flow path.
2. Enter applicable Conditions and Required Actions for systems made inoperable by PIVs.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more flow paths with leakage from one or more RCS PIVs not within limit.	Check ---NOTE--- Each valve used to satisfy Required Action A.1 and Required Action A.2 shall have been verified to meet SR 3.4.6.1 and be in the reactor coolant pressure boundary (or the high pressure portion of the system). ---	(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.8.1 NOTE Not required to be performed in MODE 3.	In accordance with Inservice Testing Program or [18] months
Verify equivalent leakage of each RCS PIV is ≤ 0.5 gpm per nominal inch of valve size up to a maximum of 5 gpm, at an RCS pressure ≥ [1040] psig and ≤ [1060] psig.	

The actual test pressure shall be ±935 psig.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
SR 3.4.12.3 ----------NOTE---------- Only required to be met in MODES 1, 2, 3, and 4 with reactor steam dome pressure ≥ 25 psig. ---------- Verify the difference between the bottom head coolant temperature and the reactor pressure vessel (RPV) coolant temperature is within the limits specified in the PTLR.	Once within 15 minutes prior to each startup of a recirculation pump during recirculation pump startup
SR 3.4.12.4 ----------NOTE---------- Only required to be met in MODES 1, 2, 3, and 4. ---------- Verify the difference between the reactor coolant temperature in the recirculation loop to be started and the RPV coolant temperature is within the limits specified in the PTLR.	Once within 15 minutes prior to each startup of a recirculation pump
SR 3.4.12.5 ----------NOTE---------- Only required to be performed when tensioning the reactor vessel head bolting studs. ---------- Verify reactor vessel flange and head flange temperatures are within the limits specified in the PTLR.	30 minutes

(continued)

INSERT SR 3.4.12.5

INSERT SR 3.4.12.6

11. Required Action A.2, which requires the high pressure portion of the affected system to be isolated from the low pressure portion by use of a second closed manual, deactivated automatic, or check valve, has been deleted. The Current Licensing Basis for WNP-2 does not include closing a second valve. As described in the WNP-2 response to Generic Letter 87-06, "Periodic Verification of Leak Tight Integrity of Pressure Isolation Valves," WNP-2 tests the valves and if one is found to be leaking beyond the allowable limits, the penetration will be isolated by one valve that meets the leakage limits. This will preclude an intersystem LOCA from occurring on the affected system. Therefore, the Required Action is not needed. In addition, the Note to Required Action A.1 has been modified to reflect this deletion. Required Action A.1 Note has also been modified to only apply to a check valve, consistent with Current Licensing Basis.

12. The bracketed requirement/information has been deleted since it is not applicable to WNP-2. The following requirements have been renumbered, where applicable, to reflect this deletion.

13. Editorial changes have been made to achieve consistency with the Writer's Guide.

14. A Note has been added to allow a channel to be inoperable for up to 6 hours solely for performance of required Surveillances, provided the other Leakage Detection System channel is OPERABLE. This Note is similar to other Notes in the ITS, which allow channels that provide automatic actions to be inoperable for up to 6 hours. This instrumentation only provides indication, and the 6 hour allowance is not allowed unless the other channel is OPERABLE. This change has previously been approved at Georgia Power Company's Plant Hatch Units 1 and 2, in amendments 185 and 125, respectively.

15. The words in the LCO have been changed from "pump starting" to "loop" since the Current WNP-2 Licensing Basis includes additional recirculation loop requirements. These additional requirements have been added as proposed SRs 3.4.12.5 and 3.4.12.6. The following requirements have been renumbered due to this addition.

16. The Notes to NUREG SR 3.4.11.3 and SR 3.4.11.4 have been modified to only require the SRs to be met during the recirculation pump startup. This is when the actual stresses occur, and when the SRs really need to be met (consistent with Current Licensing Basis). The added words are consistent with the wording currently in the Bases for 3.4.11 (LCO Section, item c), which states the following; "The temperature difference between the reactor coolant in the respective recirculation loop and in the reactor vessel meets the limit of the PTLR during recirculation pump startup."

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

3.5.1 ECCS–Operating

LCO 3.5.1 Each ECCS injection/spray subsystem and the Automatic Depressurization System (ADS) function of ~~eight~~ safety/relief valves shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3, except ADS valves are not required to be OPERABLE with reactor steam dome pressure ≤ ~~150~~ psig.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One low pressure ECCS injection/spray subsystem inoperable.	A.1 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	~~7~~ days
B. High Pressure Core Spray (HPCS) System inoperable.	B.1 Verify by administrative means RCIC System is OPERABLE when RCIC is required to be OPERABLE.	~~1 hour~~ Immediately
	AND	
	B.2 Restore HPCS System to OPERABLE status.	14 days

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.1.1	Perform required visual examinations and leakage rate testing except for primary containment air lock testing, in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions. The leakage rate acceptance criterion is $\leq 1.0 \cdot L_a$. However, during the first unit startup following testing performed in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, the leakage rate acceptance criteria are $< 0.6\ L_a$ for the Type B and Type C tests, and $< 0.75\ L_a$ for the Type A test.	-----NOTE----- SR 3.0.2 is not applicable ---------- In accordance with 10 CFR 50, Appendix J, as modified by approved exemptions the Primary Containment Leakage Rate Testing Program
SR 3.6.1.1.2	Verify primary containment structural integrity in accordance with the Primary Containment Tendon Surveillance Program.	In accordance with the Primary Containment Tendon Surveillance Program
SR 3.6.1.1.2	Verify drywell to suppression chamber bypass leakage rate is less than or equal to the equivalent leakage rate through an orifice 0.005 ft^2 at an initial differential pressure of ≥ 1.5 psid.	24 months AND ----NOTE----- Only required after two consecutive tests fail and continues until two consecutive tests pass ---------- 12 months

(40) the Primary Containment Leakage Rate Testing Program

(B)

(1)

(2)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.2.1	----------NOTES---------- 1. An inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. 2. Results shall be evaluated against acceptance criteria of SR 3.6.1.1.1, in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions. ---------- Perform required primary containment air lock leakage rate testing in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions. The acceptance criteria for air lock testing are: a. Overall air lock leakage rate is ≤ [2 scfh] when tested at ≥ P_a. b. For each door, leakage rate is ≤ [2 scfh] when the gap between the door seals is pressurized to ≥ [1.0 P_a].	applicable to (40) ----NOTE---- SR 3.0.2 is not applicable ---------- In accordance with 10 CFR 50, Appendix J, as modified by approved exemptions (40) the Primary Containment Leakage Rate Testing Program
SR 3.6.1.2.2	Verify primary containment air lock seal air flask pressure is ≥ [90] psig.	7 days

(40) the Primary Containment Leakage Rate Testing Program.

(B) (1)

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. Required Action and associated Completion Time of Condition A, B, C, D, or E not met in MODE 1, 2, or 3.	D.1	Be in MODE 3.	12 hours
	AND		
	D.2	Be in MODE 4.	36 hours
G. Required Action and associated Completion Time of Condition A, B, C, D, or E not met for PCIV(s) required to be OPERABLE during movement of irradiated fuel assemblies in the [primary or secondary containment].	G.1	--------NOTE-------- LCO 3.0.3 is not applicable. ---------- Suspend movement of irradiated fuel assemblies in [primary and secondary containment].	Immediately
H. Required Action and associated Completion Time of Condition A, B, C, D, or E not met for PCIV(s) required to be OPERABLE during CORE ALTERATIONS.	H.1	Suspend CORE ALTERATIONS.	Immediately
F. Required Action and associated Completion Time of Condition A, B, C, D, or E not met for PCIV(s) required to be OPERABLE during MODE 4 or 5 ~~or during operations with a potential for draining the reactor vessel (OPDRVs).~~	F.1	Initiate action to suspend operations with a potential for draining the reactor vessel (OPDRVs).	Immediately
	OR		
	F.2	Initiate action to restore valve(s) to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
SR 3.6.1.3.9 NOTES [1. Only required to be met in MODES 1, 2, and 3.] 2. Results shall be evaluated against acceptance criteria of SR 3.6.1.1.1 in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions. Verify the combined leakage rate for all secondary containment bypass leakage paths is ≤ 0.74 scfh when pressurized to ≥ [ ] psig, P_a.	NOTE SR 3.0.2 is not applicable. In accordance with 10 CFR 50, Appendix J, as modified by approved exemptions
SR 3.6.1.3.10 Verify leakage rate through [all] four main steam lines is ≤ [100] scfh when tested at ≥ [ ] psig.	NOTE SR 3.0.2 is not applicable. In accordance with 10 CFR 50, Appendix J, as modified by approved exemptions

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
SR 3.6.1.3.[10]	
----------NOTES---------- 1. Only required to be met in MODES 1, 2, and 3. 2. Results shall be evaluated against acceptance criteria of SR 3.6.1.1.1 in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions. ----------	
Verify combined leakage rate of [1 gpm times the total number of PCIVs] through hydrostatically tested lines that penetrate the primary containment is not exceeded when these isolation valves are tested at ≥ 1.1 P_a. within limits.	----NOTE---- SR 3.0.2 is not applicable ---------- In accordance with 10 CFR 50, Appendix J, as modified by approved exemptions the Primary Containment Leakage Rate Testing Program
SR 3.6.1.3.12	
----------NOTE---------- Only required to be met in MODES 1, 2, and 3. ----------	
Verify each [ ] inch primary containment purge valve is blocked to restrict the valve from opening > [50]%.	[18] months

* Insert BWR/4 3.6.3.2 (33)

Primary Containment Atmosphere Mixing System (5) [Drywell Cooling System Fans] 3.6.3.2 (B)

3.6 CONTAINMENT SYSTEMS

Primary Containment Atmosphere Mixing System (B)

3.6.3.2 [Drywell Cooling System Fans] (5)

head area return

LCO 3.6.3.2 Two [drywell cooling system fans] shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One [required] (1) [drywell cooling system fan] inoperable. head area return (5)	A.1 --------NOTE-------- LCO 3.0.4 is not applicable. (20) ---------- Restore [required] (1) [drywell cooling system fan] to OPERABLE status. (5) head area return	30 days
B. Two [required] (1) [drywell cooling system fans] inoperable. (5) head area return	B.1 Verify by administrative means that the hydrogen control function is maintained. (16) and oxygen	1 hour AND Once per 12 hours thereafter (34)
	AND	
	B.2 (1) Restore one [required] [drywell cooling system fan] to OPERABLE status. (5) head area return	7 days
C. Required Action and Associated Completion Time not met. (20)	C.1 Be in MODE 3.	12 hours

(33) * This BWR/4 Specification Insert was used because it best represented the WNP-2 design.

Insert Page 3.6-41a

*Insert BWR/4 3.6.3.2

(33)

(5) Primary Containment Atmosphere Mixing System [Drywell Cooling System Fans] 3.6.3.2 (B)

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.6.3.2.1	Operate each (1) [required] [drywell] cooling system fan for ≥ [15] minutes. (5) head area return (5)	92 days
(1) SR 3.6.3.2.2	Verify each [required] [drywell cooling system fan] flow rate is ≥ [500] scfm.	[18] months

*This BWR/4 Specification Insert was used because it best represented the WNP-2 design.

(33)

Insert Page 3.6-41b

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
SECTION 3.6 - CONTAINMENT SYSTEMS

1. This bracketed requirement has been deleted because it is not applicable to WNP-2. The following requirements have been renumbered, where applicable, to reflect this deletion.

2. The drywell to suppression chamber bypass leakage Surveillance Requirement has been added consistent with Current Licensing Basis. The words are essentially consistent with the BWR/4 ITS (NUREG-1433) except a few minor changes due to the manner in which WNP-2 performs the test. In addition, the Frequency has been changed to 24 months and 12 months, respectively, since the normal "refueling cycle intervals" (i.e., 18 months) have been extended to 24 months in the WNP-2 ITS.

3. The WNP-2 design only includes one primary containment air lock, similar to the BWR/4 design. Therefore, numerous changes have been made to reflect the one air lock design. The changes are consistent with the BWR/4 ITS (NUREG-1433), except where discussed separately.

4. The word "primary" has been added for clarity and consistency.

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

6. The WNP-2 design includes reactor building-to-suppression chamber vacuum breakers, similar to the BWR/4 design. Therefore, the LCO has been modified to exempt these PCIVs from this LCO, consistent with the BWR/4 ITS (NUREG-1433). The WNP-2 design also includes EFCVs and TIPs, similar to the BWR/4 design. Therefore, ACTION C Completion Time has been modified and proposed SR 3.6.1.3.4, SR 3.6.1.3.8, and SR 3.6.1.3.9 have been added, consistent with the BWR/4 ITS (NUREG-1433).

7. The words "in MODES 1, 2, and 3" have been deleted from this ACTIONS Note since there are no PCIV leakage tests required in MODES other than MODES 1, 2, and 3 for WNP-2 (i.e., there are no PCIVs required to be OPERABLE in MODES other than MODES 1, 2, and 3 that have specific leakage limits). In addition, NUREG SR 3.6.1.3.2, Note 1, NUREG SR 3.6.1.3.9, Note 1, and NUREG SR 3.6.1.3.11, Note 1 have been deleted for the same reason. The following Notes have been renumbered, if applicable, due to these Notes deletion.

8. The words inside the brackets have been modified to reflect the different leakage categories. Since there is more than one, the generic word "leakage" has been used. The PCIVs are required to be OPERABLE such that they are in the accident condition or can be automatically repositioned to the accident condition, and certain PCIVs have individual leakage limits. These leakage limits are in addition to the type A, B, and C limits required by LCO 3.6.1.1, Primary Containment OPERABILITY. If a type A, B, or C limit were exceeded due to an individual valve exceeding its specific leakage limit, Note 4 to LCO 3.6.1.3 would require the ACTIONS of LCO 3.6.1.1 to be taken (which require primary containment to be restored within 1 hour).

8. (continued)

The change was made to reflect that different compensatory actions are required depending upon the cause of the inoperability. In the WNP-2 ITS, ACTION A is taken if the PCIV is inoperable for reasons other than leakage; ACTIONS D and E are required if the SRs for individual valve lekage limits are not met. Currently (in the NUREG), Condition A would only exempt purge valve leakage requirements (which WNP-2 does not have) and secondary containment bypass leakage requirements. If a MSIV or a hydrostatically tested valve was not meeting the leakage limits, Condition A would be entered and Required Action A would be required. This Required Action allows the penetration to be isolated. However, isolating the penetration can be performed by using the leaking valve. This would not provide adequate compensatory measures to allow continued operation. When a MSIV or hydrostatically tested valve leakage is not within limits, Condition D should be entered. The Required Action for this Condition would require the leakage to be restored within limit in 4 hours, consistent with the time provided in Required Action A.1 to isolate the penetration. As discussed in the NUREG Bases, the leakage can be restored by isolating the penetration with a valve not exceeding the leakage limits. This is more restrictive than Required Action A.1, which allows isolation using the leaking valve. Conditions B and C have also been modified to exclude leakage. These Conditions are appropriate if the valve is in the incorrect position or will not close. As discussed above, the Required Actions for Conditions B and C would also allow the penetration to be isolated using the leaking valve if the bracketed phrase were not deleted. (B)

9. The WNP-2 design includes the drywell as part of the primary containment and the primary containment is inerted while operating, similar to the BWR/4 design. Therefore, changes have been made to the requirements which check proper position of isolation devices, similar to the BWR/4 ITS (NUREG-1433). (B)

10. The Completion Time of "Once per 31 days" was clarified by adding "for isolation devices outside primary containment". Also the new Completion Time, "Prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days, for isolation devices inside primary containment", was added. These words were added to avoid unnecessary exposure to individuals entering primary containment to comply with this Required Action for affected devices which may be inside primary containment. This change results in this Required Action being required at the same Completion Times as Required Action A.2, which is a similar type Required Action.

11. The time to restore MSIV leakage to within limit has been changed to 8 hours, consistent with the time provided to restore an inoperable MSIV (for reasons other than leakage) in ACTION A. Required Action A.1 allows 8 hours to isolate the affected main steam line when an MSIV is inoperable due to a reason not involving leakage. This could include an MSIV that will not automatically isolate (which means it is essentially full open). Therefore, the Completion Time has been modified to be consistent with that provided in ACTION A.

12. The acronym "OPDRVs" has been defined, consistent with the format of the ITS, since it is the first use of this term in this Specification.

13. The Appendix J testing requirements and associated acceptance criteria, or exemptions to applying leakage to that acceptance criteria, is adequately addressed in proposed SR 3.6.1.1.1, The deleted Notes serve no purpose. Additionally, the ACTIONS Note 4 ("Enter applicable Conditions...results in exceeding L_a") provides appropriate and sufficient control to direct the proper ACTIONS should excessive leakage be discovered. In addition, these Notes were approved to be deleted from NUREG-1434, Revision 1 per change package BWR-14, C.3, but apparently were not deleted. The BWR/4 ITS (NUREG-1433) did delete the Note for the hydrostatically tested lines (NUREG-1433 SR 3.6.1.3.14).

14. The Primary Containment Pressure LCO has been deleted. The current WNP-2 Drywell and Suppression Chamber Internal Pressure LCO is based on the initial assumption of 0.75 psig in the safety analysis, and is required in MODES 1, 2, and 3. A recent GE evaluation (GE-NE-208-17-0993) shows that an initial drywell pressure of 2.0 psig is acceptable for ensuring containment pressure design limits are not exceeded. This initial pressure was utilized in determining a new P_a, and has been approved by the NRC to support the WNP-2 power uprate amendment (NRC letter from J.W. Clifford to J.V. Parrish, "Issuance of Amendment 137 for the Washington Public Power Supply System Nuclear Project No. 2," dated May 2, 1995). This LCO is not needed since the RPS high drywell pressure scram will trip the unit prior to exceeding 2.0 psig (the Allowable Value is 1.88 psig, with a Trip Setpoint of 1.68 psig), effectively placing the unit in MODE 3. While the RPS trip is not required in MODE 3, the Emergency Operating Procedures (EOPs) will govern actions if the drywell pressure exceeds 1.68 psig (effectively bounding the 2.0 psig limit). The EOPs will require entry into the RPV Control and Primary Containment Control actions. These actions require steps to be taken to reduce primary containment pressure to less than 1.68 psig. The negative pressure limit (-1.0 psig) is essentially controlled by the proper operation of the reactor building-to-suppression chamber and the suppression chamber-to-drywell vacuum breakers. These vacuum breakers are designed to ensure the negative pressure design limit of the primary containment is not exceeded, and are designed to open at -0.5 psid. Thus, the internal pressure cannot exceed the current -1.0 psig limit (which is also in Technical Specifications to preclude the negative pressure design limit of the primary containment from being exceeded) under normal circumstances (i.e., non-accident conditions). Since the vacuum breakers and their setpoints are required by Technical Specifications during MODES 1, 2, and 3 (proposed LCOs 3.6.1.6 and 3.6.1.7), the negative pressure limit part of the LCO is also not needed.

15. The Specifications following NUREG LCO 3.6.1.4 have been renumbered to reflect the deletion of NUREG LCO 3.6.1.4.

16. The proper plant specific information/nomenclature/value has been provided.

17. The WNP-2 design does not include the Low-Low Set Function of the Safety/Relief Valves. Therefore, this Specification has been deleted.

18. The WNP-2 design does not include an automatically actuated RHR Drywell Spray System. Therefore, the Note to NUREG SR 3.6.1.7.1 and NUREG SR 3.6.1.7.3 have been deleted. In addition, since the system is manually initiated, the phrase "or can be aligned to the correct position" has been added to the valve position check Surveillance (NUREG SR 3.6.1.7.1), consistent with other manual system valve position checks. The WNP-2 design also does not include an accurate measurement of drywell spray, nor is an actual value assumed in the safety analysis (it is just assumed to be turned on). Therefore, NUREG SR 3.6.1.7.2 has been deleted.

19. Two new Specifications have been added, proposed LCO 3.6.1.6 and LCO 3.6.1.7. These Specifications are from the BWR/4 ITS (NUREG-1433 LCOs 3.6.1.7 and 3.6.1.8), since the WNP-2 design is similar to the BWR/4 design with regard to the vacuum breakers. Therefore, the BWR/4 LCOs are used and any deviations from the BWR/4 ITS are discussed.

20. Typographical/grammatical error corrected.

21. The Frequency has been changed to "In accordance with the Inservice Testing Program," consistent with other Frequencies for similar components covered by the IST Program. The current IST Program Frequency is 92 days, so no technical change has been made.

22. The WNP-2 design for the suppression chamber-to-drywell vacuum breakers has two disks per vacuum breaker. With either disk closed, the isolation capability of the line is maintained. Therefore, the ACTIONS have been modified to reflect this design. The changes are as follows:

    a. A Note has been added to Condition B to allow separate entry on a per valve basis. This Note is similar to that allowed in the NUREG-1433 LCO 3.6.1.7, as a Note to the ACTIONS (See Insert Page 3.6-24a). Since there is only one vacuum breaker per line, this is essentially the same as allowing entry on a per line basis (In NUREG-1433 LCO 3.6.1.7, each line has two vacuum breakers, while in this proposed LCO, each line has one vacuum breaker, with two disks per vacuum breaker);

    b. Condition B has been modified to apply to more than one vacuum breaker, but only if one of the two disks is closed (i.e., one disk is not closed in one or more vacuum breakers). The time allowed to close the open vacuum breaker disk has been changed to 72 hours. With one of the two disks of a vacuum breaker not closed, the other disk will still ensure isolation capability of the penetration is maintained. These changes are consistent with the NUREG-1433 LCO 3.6.1.7, ACTION A, which allows 72 hours for one or more lines with one vacuum breaker not closed; and

22. (continued)

c. A new ACTION has been added (proposed ACTION C) for when both disks of a vacuum breaker are not closed. Two hours is allowed to close one of the two disks. This new ACTION is consistent with the original NUREG-1433 LCO 3.6.1.8, ACTION B, which allows 2 hours to close an open suppression chamber-to-drywell vacuum breaker. In addition, NUREG-1433 LCO 3.6.1.8, ACTION C has been renumbered to reflect this new ACTION.

23. The second Frequency to NUREG-1433 SR 3.6.1.8.1 requires the vacuum breakers to be verified closed after they may have been opened. This Frequency is not needed. Surveillances must be continually met (per SR 3.0.1), thus if the vacuum breakers are open and the Surveillance is not due yet, the SR would still be considered not met, and appropriate ACTIONS taken. There are many other instances where valves are required to be closed, and verified closed on a periodic basis, If these other valves are cycled (e.g., ECCS valves) plant administrative controls ensure they are left in the correct position; a special Frequency of the Surveillance is not required. In addition, these vacuum breakers have position indication in the control room, and are continuously monitored by control room operators. If conditions exist for the vacuum breakers to be potentially opened (e.g., venting the drywell), control room operators would be alert to the possibility and ensure the vacuum breakers were closed at the completion of the evolution. Also, this Surveillance Frequency is not required in current WNP-2 Technical Specifications.

24. The third Frequency to NUREG-1433 SR 3.6.1.8.2 requires a functional test of the vacuum breakers (i.e., cycle the vacuum breakers) within 12 hours after the vacuum breakers have cycled. In a September 8, 1992 memorandum to C.I. Grimes from C.E. McCracken, the only basis for this Frequency is given as ..."in case the event caused damage to one or more vacuum breakers."

Since the vacuum breakers are designed to operate and assumed to function after a LOCA blowdown, their operation as designed after some steam release or change in internal pressure should not raise questions regarding immediate OPERABILITY of the vacuum breakers. In addition, the WNP-2 design include two disks per vacuum breaker, thus if one disk did stick open when it was opened during an operation, the other closed disk would still ensure isolation capability is maintained. Therefore, this Frequency, which is not in the current WNP-2 Technical Specifications, has not been added to the WNP-2 ITS.

25. The WNP-2 design does not include a Penetration Valve Leakage Control System. Therefore, this Specification has been deleted.

26. The Specification following NUREG LCO 3.6.1.8 has been renumbered to reflect the deletion of NUREG LCO 3.6.1.8.

27. THERMAL POWER in the range of 1% RTP is not readily quantified with much accuracy. While range 7 on IRMs approximates 1% RTP, this power level can also be approximated from SRMs and even by determining the point of adding heat. These acceptable options are desired to be maintained in plant procedures, with the ITS requirement as it is in the existing WNP-2 Technical Specifications; i.e., 1% RTP. Therefore, the LCO and ACTIONS have been modified to reflect the 1% RTP requirement.

28. These additional words have been deleted for consistency. These words do not appear in the BWR/4 ITS (NUREG-1433). These words were approved to be deleted from NUREG-1434, Revision 1 per change package BWR-6, C.4, but apparently were not deleted.

29. A new ACTION has been added (ACTION B) to provide a restoration time for when both suppression pool cooling subsystems are inoperable. The proposed 8 hour Completion Time is consistent with the current time provided when both drywell spray subsystems are inoperable. The time is considered appropriate since an immediate shutdown has the potential for resulting in a unit scram and discharge of steam to the suppression pool, when both suppression pool cooling subsystems are inoperable and incapable of removing the generated heat. The 8 hours provides some time to restore one of the subsystems prior to requiring a shutdown (thus precluding the potential problem described above), yet is short enough that it does not significantly increase the probability of an accident to occur during this additional time. NUREG ACTION B has also been renumbered and modified (by the deletion of the words "of Condition A")to reflect this new ACTION.

30. The WNP-2 design does not include a Suppression Pool Makeup System. Therefore, this Specification has been deleted.

31. This reviewer's type of note has been deleted. This information is for the NRC reviewer to be keyed in to what is needed to meet this requirement. This is not meant to be retained in the final version of the plant specific submittal.

32. The WNP-2 design does not include Primary Containment and Drywell Hydrogen Ignitors nor a Drywell Purge System. Therefore, these Specifications have been deleted.

33. Two new Specifications have been added, proposed LCO 3.6.3.2 and proposed LCO 3.6.3.3. These Specifications are from the BWR/4 ITS (NUREG-1433), since the WNP-2 design is similar to the BWR/4 design with regards to the Primary Containment Atmosphere Mixing System and oxygen concentration requirements of the primary containment. Therefore, the BWR/4 LCOs are used and any deviations from the BWR/4 ITS are discussed. (B)

34. The periodic Completion Time of "once per 12 hours" for Required Action B.1 has been deleted. The Reviewer's Note in the Bases for this Required Action states "The following is to be used if a non-Technical Specification alternate hydrogen control function is used to justify this Condition: In addition, the alternate hydrogen control system capability must be verified once per 12 hours thereafter to ensure

34. (continued)

its continued availability." The alternate hydrogen control function used for this Required Action is the RHR Drywell Spray System, which is in the ITS (LCO 3.6.1.5). Therefore, this additional periodic Completion Time is not needed.

35. NUREG SR 3.6.4.1.3 has been modified to only require all inner secondary containment access doors or all outer secondary containment access doors per access opening to be closed. The WNP-2 design includes more than two doors per access opening in some accesses, thus requiring all inner or all outer doors to be closed is more restrictive than the current WNP-2 Technical Specification requirements.

36. The WNP-2 design does not include a drywell internal to the primary containment (NUREG-1434 is based on a Mark III containment; WNP-2 has a Mark II containment). Therefore, the Drywell related LCOs (LCO 3.6.5.1 through LCO 3.6.5.6) have been deleted.

37. Generic change TSTF-30 has not been adopted. WNP-2 is evaluating this change and will decide whether or not to incorporate this change at a later date.

38. Editorial change made to be consistent with other similar requirements in the ITS.

39. The words in NUREG Condition I (proposed Condition F), "or during operations with a potential for draining the reactor vessel (OPDRVs)," have been deleted. The Condition is still applicable in MODES 4 and 5, which are the only MODES that OPDRVs can be performed. In addition, there are no PCIVs required to be OPERABLE in the WNP-2 ITS whose Applicability is only during OPDRVS. The only PCIVs required when not in MODES 1, 2, and 3 are the RHR shutdown cooling isolation valves, and their Applicability is MODES 4 and 5. Therefore, the "during OPDRVs" Applicability is duplicative of the MODES 4 and 5 Applicability (which is being maintained) and can be deleted. (B)

40. A Primary Containment Leakage Rate Testing Program has been added to Section 5.5, consistent with the letter from C. I. Grimes to D. J. Modeen, dated November 2, 1995. This letter transmitted the draft ITS pages marked up to reflect Appendix J, Option B testing requirements. The Program references the requirements of 10 CFR 50 Appendix J and approved exceptions, therefore the Surveillances have been modified to reference the Program. (L)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
SR 3.8.1.15 ----------NOTES---------- 1. This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ [2] hours loaded ≥ [4500] kW and ≤ [5000] kW for [Division 1 and 2] DGs, and ≥ [3300] kW and ≤ [3500] kW for [Division 3] DG. Momentary transients outside of load range do not invalidate this test. 2. All DG starts may be preceded by an engine prelube period. ---------- Verify each required DG starts and achieves, in ≤ [10] seconds, voltage ≥ [3744] V and ≤ [4576] V and frequency ≥ [58.8] Hz and ≤ [61.2] Hz.	a. For DG-1 and DG-2, [24] months
SR 3.8.1.16 ----------NOTE---------- This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify each required DG: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	[24] months

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.2 AC Sources – Shutdown

LCO 3.8.2 The following AC electrical power sources shall be OPERABLE:

a. One qualified circuit between the offsite transmission network and the onsite Class 1E AC electrical power distribution subsystem(s) required by LCO 3.8.10, "Distribution Systems – Shutdown"; and

b. One diesel generator (DG) capable of supplying one division of the Division 1 or 2 onsite Class 1E AC electrical power distribution subsystem(s) required by LCO 3.8.10; and

c. One qualified circuit, other than the circuit in LCO 3.8.2.a, between the offsite transmission and the Division 3 onsite Class 1E electrical power distribution subsystem, or the Division 3 DG capable of supplying the Division 3 onsite Class 1E AC electrical power distribution subsystem, when the Division 3 onsite Class 1E electrical power distribution subsystem is required by LCO 3.8.10.

APPLICABILITY: MODES 4 and 5,
During movement of irradiated fuel assemblies in the primary or secondary containment.

NOTE
LCO 3.0.3 is not applicable.
TSTF-36

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ~~LCO Item a. not met.~~ Required offsite circuit inoperable.	NOTE Enter applicable Condition and Required Actions of LCO 3.8.10, ~~with one~~ required division de-energized as a result of Condition A.	when any
	A.1 Declare affected required feature(s) with no offsite power available inoperable.	Immediately
	OR	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	A.2.2 Suspend movement of irradiated fuel assemblies in the ~~primary and~~ secondary containment.	Immediately
	AND	
	A.2.3 Initiate action to suspend operations with a potential for draining the reactor vessel (OPDRVs).	Immediately
	AND	
	A.2.4 Initiate action to restore required offsite power circuit to OPERABLE status.	Immediately

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

LCO 3.8.3 The stored diesel fuel oil, lube oil, and starting air subsystem shall be within limits for each required diesel generator (DG).

APPLICABILITY: When associated DG is required to be OPERABLE.

ACTIONS

NOTE
Separate Condition entry is allowed for each DG.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more DGs with fuel oil level: 1. For [DG 11 or 12], < [62,000] gal and ≥ [49,080] gal; and 2. For [DG 13], < [41,200] gal and ≥ [33,500] gal.	A.1 Restore fuel oil level to within limits.	48 hours
B. One or more DGs with lube oil inventory: 1. For [DG 10 or 12], < [ ] gal and ≥ [425] gal; and 2. For [DG 13], < [ ] gal and ≥ [ ] gal.	B.1 Restore lube oil inventory to within limits.	48 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more DGs with stored fuel oil total particulates not within limit.	C.1 Restore stored fuel oil total particulates to within limit.	7 days
D. One or more DGs with new fuel oil properties not within limits.	D.1 Restore stored fuel oil properties to within limits.	30 days
E. One or more DGs with required starting air receiver pressure < 225 psig and ≥ 125 psig.	E.1 Restore required starting air receiver pressure to ≥ 225 psig.	48 hours
F. Required Action and associated Completion Time not met. OR One or more DGs with diesel fuel oil, lube oil, or starting air subsystem not within limits for reasons other than Condition A, B, C, D, or E.	F.1 Declare associated DG inoperable.	Immediately

1. For DG-1 or DG-2,
2. For DG-3, < 223 psig and ≥ 150 psig.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.4.1	Verify battery terminal voltage is: a. ≥ [129] V on float charge for the 125V batteries; and (126) b. ≥ 252 V for the 250 V battery	7 days
SR 3.8.4.2	Verify no visible corrosion at battery terminals and connectors. OR Verify battery connection resistance [is ≤ [1.5 E-4 ohm] for inter-cell connections, ≤ [1.5 E-4 ohm] for inter-rack connections, ≤ [1.5 E-4 ohm] for inter-tier connections, and ≤ [1.5 E-4 ohm] for terminal connections].	92 days Insert SR 3.8.4.2
SR 3.8.4.3	Verify battery cells, cell plates, and racks show no visual indication of physical damage or abnormal deterioration that degrades battery performance. (TSTF-38)	~~12~~ months
SR 3.8.4.4	Remove visible corrosion and verify battery cell to cell and terminal connections are clean and tight, and coated with anti-corrosion material.	~~12~~ months
SR 3.8.4.5	Verify battery connection resistance [is ≤ [1.5 E-4 ohm] for inter-cell connections, ≤ [1.5 E-4 ohm] for inter-rack connections, ≤ [1.5 E-4 ohm] for inter-tier connections, and ≤ [1.5 E-4 ohm] for terminal connections].	~~12~~ months Insert SR 3.8.4.5

(continued)

INSERT SR 3.8.4.2

≤ 24.4 E-6 ohms for inter-cell connectors of the Division 1 and 2 batteries, ≤ 169 E-6 ohms for inter-cell connectors of the Division 3 battery, and ≤ 20% above the resistance as measured during installation for inter-tier and inter-rack connectors.

INSERT SR 3.8.4.5

≤ 24.4 E-6 ohms for inter-cell connectors of the Division 1 and 2 batteries, ≤ 169 E-6 ohms for inter-cell connectors of the Division 3 battery, and ≤ 20% above the resistance as measured during installation for inter-tier and inter-rack connectors.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
SR 3.8.4.8 ----------NOTE---------- This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify battery capacity is ≥ {80}% of the manufacturer's rating when subjected to a performance discharge test or a modified performance discharge test. (2) for the 125 V batteries and ≥ 83.4% of the manufacturer's rating for the 250 V battery.	60 months AND 12 months when battery shows degradation or has reached {85}% of expected life with capacity < 100% of manufacturer's rating (2) (B) AND 24 months when battery has reached {85}% of the expected life with capacity ≥ 100% of manufacturer's rating (2)

20. (continued)

Therefore, the 250 V DC electrical power subsystem and 250 V DC electrical power distribution subsystem are support systems for only three TS related functions. As such, the requirement to immediately declare the associated supported features inoperable is appropriate and consistent with the WNP-2 design. Due to this change: a) proposed ACTION A of LCO 3.8.4, proposed ACTION B of LCO 3.8.7, and the second Completion Time of proposed Required Action A.1 of LCO 3.8.7 have also been modified to only be applicable to the Division 1 and Division 2 125 V batteries, b) NUREG ACTION C of LCO 3.8.4 has been renumbered as ACTION D, and c) proposed Condition F of LCO 3.8.7 has been modified by the addition of the words "division with" since Division 1 has a 125 V DC electrical power distribution subsystem and a 250 V DC electrical power distribution subsystem (thus if both were inoperable, this ACTION would unnecessarily require a LCO 3.0.3 entry).

21. Not used.

22. Due to the WNP-2 design (spare 100% charger for the Division 1 and 2 batteries), individual battery chargers can be tested without compromising compliance with the Division 1 and 2 requirements of the LCO. The Division 3 battery would only affect the HPCS System, which is allowed to be inoperable for 14 days in accordance with proposed LCO 3.5.1. Therefore, the Mode restriction is not needed (and is not currently required by Current Licensing Basis). In addition, since the test can be performed without compromising the Division 1 and 2 DC loads, SR 3.8.4.6 is not excepted from performance when the unit is shutdown (per the Note to SR 3.8.5.1).

23. The load descriptions have been relocated to the Bases. The battery charger vendors recommend a load test that step loads the battery chargers at three distinct loads, not just a test at the 100% rating. The battery manufacturers recommend that in addition to testing at the 100% rating, the battery chargers should initially be loaded at 50% for 30 minutes, 75% for the next 30 minutes, then at the full load rating for the next 30 minutes. This description has been placed in the Bases. This relocation is similar to the NUREG allowance to relocate the battery load profile to plant controlled documents.

24. The word "values" in the third Condition of Condition B has been changed to "limits" to more closely match the LCO description. In addition, the word "Allowable" in Table 3.8.6-1 has been deleted to be consistent with the manner in which Category C "Limits" are described in the ACTIONS. This will also avoid confusion with the term "Allowable Value" used in the Instrumentation Section.

25. The words "and following" have been added to footnote a to allow the electrolyte level to be temporarily above the limit following the equalize charge as well as during the charge. As stated in the Bases for this footnote (in Table 3.8.6-1 description), IEEE-450 recommends that electrolyte level readings not be taken until 72 hours after the equalize charge. This allows time for the electrolyte temperature to

25. (continued)

stabilize and the level reading to be a "true" reading. Without the added words, the limit may not be met upon completion of the charge and unnecessary ACTIONS would have to be taken.

26. This Note is not needed and has been deleted. ACTION E states that if Division 3 electrical power distribution subsystem is inoperable, then the HPCS System is to be declared inoperable and the HPCS ACTIONS in LCO 3.5.1 taken. As soon as it is, then the Note states that Division 3 electrical power distribution subsystem is not required to be OPERABLE. Since that is the only reason that the HPCS System is inoperable, then it appears that the HPCS System could be declared OPERABLE again. As soon as this is done, the Note would apply again and HPCS would again be declared inoperable, and ACTIONS of LCO 3.5.1 again required. To alleviate this confusion, and for consistency with LCO 3.8.4, which does not have the Note, this Note has been deleted. Without the Note, when Division 3 electrical power distribution subsystem is inoperable, ACTION E will be entered and appropriate Required Actions taken.

27. The "voltage" check has been replaced with a "power availability" check since voltage indication is not available to all the AC and DC buses.

28. The word "handling" has been replaced with "movement" for consistency with other places in the TS where this Required Action appears.

3.9 REFUELING OPERATIONS

3.9.1 Refueling Equipment Interlocks

LCO 3.9.1 The refueling equipment interlocks associated with the refuel position shall be OPERABLE.

APPLICABILITY: During in-vessel fuel movement with equipment associated with the interlocks when the reactor mode switch is in the refuel position.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required refueling equipment interlocks inoperable.	A.1 Suspend in-vessel fuel movement with equipment associated with the inoperable interlock(s).	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.1.1	Perform CHANNEL FUNCTIONAL TEST on each of the following required refueling equipment interlock inputs: a. All-rods-in, b. Refuel platform position, and c. Refuel platform main hoist fuel loaded, and d. Refueling platform frame-mounted hoist fuel-loaded, and e. Refueling platform trolley-mounted hoist fuel-loaded.	7 days

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
SECTION 3.9 - REFUELING OPERATIONS

1. The current licensing basis WNP-2 refueling equipment interlocks have been provided.

2. The WNP-2 design includes more than one "full-in" position indication channel; therefore, the words have been changed to reflect this design.

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

4. The Applicability and Required Action have been deleted from proposed LCO 3.9.6 since they are covered by proposed LCO 3.9.7 (WNP-2 has chosen the option to have two different LCOs; one for the movement of irradiated fuel and the other for the movement of new fuel or control rods).

5. Typographical error corrected.

6. Editorial changes have been made to achieve consistency with the Writer's Guide.

7. The current wording of LCO 3.9.1 and the associated Applicability could imply that all the refueling equipment interlocks are required at all times during in-vessel fuel movement. The Current Licensing Basis only requires the interlocks associated with the refuel position, not those associated with other positions of the reactor mode switch, and only when the reactor mode switch is in the refuel position, not when it is in the shutdown position. Therefore, to avoid confusion, the LCO and Applicability have been modified to specifically state that the refueling interlocks are those associated with the refuel position, and that it is applicable when the reactor mode switch is in the refuel position. It is the belief of the Supply System that this is consistent with the intent of the NUREG; the NUREG did not intend for all the interlocks to be OPERABLE, only those associated with the refuel position, and they were only required when the reactor mode switch is in the refuel position. (B)

3.10 SPECIAL OPERATIONS

3.10.4 Single Control Rod Withdrawal–Cold Shutdown

LCO 3.10.4 The reactor mode switch position specified in Table 1.1-1 for MODE 4 may be changed to include the refuel position, and operation considered not to be in MODE 2, to allow withdrawal of a single control rod, and subsequent removal of the associated control rod drive (CRD) if desired, provided the following requirements are met:

a. All other control rods are fully inserted;

b. 1. LCO 3.9.2, "Refuel Position One-Rod-Out Interlock," and

LCO 3.9.4, "Control Rod Position Indication,"

OR

2. A control rod withdrawal block is inserted; and

c. 1. LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," MODE 5 requirements for Functions 1.a, 1.b, ~~2.a, 2.d,~~ 8.a, 8.b, 10, and 10 of Table 3.3.1.1-1,

(2) (7) (0) (1)

LCO 3.9.5, "Control Rod OPERABILITY–Refueling,"

OR

LCO 3.3.8.2, "Reactor Protection System (RPS) Electric Power Monitoring," MODE 5 requirements, and (9) (B)

2. All other control rods in a five by five array centered on the control rod being withdrawn are disarmed, ~~and~~ at which time

(4)

LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," MODE 5 requirements ~~except~~ the single control rod ~~to be~~ withdrawn ~~may~~ be assumed to be the highest worth control rod.

(to) may be changed to allow

APPLICABILITY: MODE 4 with the reactor mode switch in the refuel position.

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
SECTION 3.10 - SPECIAL OPERATIONS

1. The proper LCO number has been used.

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

3. These words have been deleted for consistency with other similar references in the TS and Bases.

4. These changes were approved to be made in NUREG-1434, Revision 1 per change package BWR-18, C.72, C.77, C.79, and C.81 but apparently were not made. These changes were made to the BWR/4 ITS, NUREG-1433, Revision 1 in accordance with change package BWR-18, C.72, C.77, C.79, and C.81.

5. Typographical/grammatical error corrected.

6. The WNP-2 rod pattern control design does not include a Rod Action Control System, but a rod worth minimizer (RWM), similar to the BWR/4 design. Therefore, the LCO, ACTIONS, and Surveillances have been modified to reflect the RWM design, and are consistent with the BWR/4 ITS, NUREG-1433.

7. The Startup Test Program has been completed at WNP-2; therefore a reference is not needed.

8. The allowance provided by this Specification is not needed at WNP-2; consequently, it has been deleted.

9. The MODE 4 and 5 Applicability of LCO 3.3.8.2, "RPS Electric Power Monitoring," as it relates to control rod withdrawal, has been revised to not include MODE 4, consistent with the Applicability of RPS Functions in LCO 3.3.1.1 (See Section 3.3, Justification for Deviations, comment 44). In MODE 4, a control rod may be withdrawn from a core cell containing one or more fuel assemblies in accordance with LCO 3.10.4, "Single Control Rod Withdrawal—Cold Shutdown." Therefore, LCO 3.10.4 includes OPERABILITY requirements for RPS Functions and control rods (LCO 3.9.5). As a result, LCO 3.10.4 has been modified to also include requirements for the RPS Electric Power Monitoring assemblies to be OPERABLE when the RPS Functions and control rods are required to be OPERABLE. (B)

5.5 Programs and Manuals

5.5.8 Ventilation Filter Testing Program (VFTP) (continued)

accordance with Regulatory Guide 1.52, Revision 2, and ASME N510-1989 at the system flowrate specified below (± 10%):

ESF Ventilation System	Flowrate (cfm)
SGT System	4012 to 4902
CREF System	900 to 1100

b. Demonstrate for each of the ESF systems that an inplace test of the charcoal adsorber shows a penetration and system bypass < 0.05% when tested in accordance with Regulatory Guide 1.52, Revision 2, and ASME N510-1989 at the system flowrate specified below (± 10%):

ESF Ventilation System	Flowrate (cfm)
SGT System	4012 to 4902
CREF System	900 to 1100

c. Demonstrate for each of the ESF systems that a laboratory test of a sample of the charcoal adsorber, when obtained as described in Regulatory Guide 1.52, Revision 2, shows the methyl iodide penetration less than the value specified below when tested in accordance with ASTM D3803-1989 at a temperature of ≤ [30°C] and greater than or equal to the relative humidity specified below:

(Method B for the SGT System and Method A for the CREF System) at a relative humidity

ESF Ventilation System	Penetration (%)	RH (%)
SGT System	0.175	70
CREF System	1.0	70

Reviewer's Note: Allowable penetration = [100% - methyl iodide efficiency for charcoal credited in staff safety evaluation] (safety factor).

Safety factor = [5] for systems with heaters.
= [7] for systems without heaters.

(continued)

5.5 Programs and Manuals

5.5.9 Explosive Gas and Storage Tank Radioactivity Monitoring Program (continued)

The program shall include:

a. The limits for concentrations of hydrogen and oxygen in the Waste Gas Holdup System and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion); and

b. A surveillance program to ensure that the quantity of radioactivity contained in [each gas storage tank and fed into the offgas treatment system] is less than the amount that would result in a whole body exposure of ≥ 0.5 rem to any individual in an unrestricted area, in the event of [an uncontrolled release of the tanks' contents]; and

c. A surveillance program to ensure that the quantity of radioactivity contained in all outdoor liquid radwaste tanks that are not surrounded by liners, dikes, or walls, capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the Liquid Radwaste Treatment System is less than the amount that would result in concentrations less than the limits of 10 CFR 20, Appendix B, Table 2, Column 2, at the nearest potable water supply and the nearest surface water supply in an unrestricted area, in the event of an uncontrolled release of the tanks' contents.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program surveillance frequencies.

5.5.10 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

(continued)

5.5 Programs and Manuals

5.5.(10) Diesel Fuel Oil Testing Program (continued)

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

1. an API gravity or an absolute specific gravity within limits,

2. a flash point and kinematic viscosity within limits for ASTM 2D fuel oil,

3. a clear and bright appearance with proper color;

b. Other properties for ASTM 2D fuel oil are within limits within 31 days following sampling and addition to storage tanks; and

c. Total particulate concentration of the fuel oil is ≤ 10 mg/l when tested every 31 days.

5.5.(11) Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not involve either of the following:

1. a change in the TS incorporated in the license; or

2. a change to the updated FSAR or Bases that involves an unreviewed safety question as defined in 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the FSAR.

d. Proposed changes that meet the criteria of 5.5.(11)b above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without

(continued)

(a) The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel Fuel Oil Testing Program test frequencies.

5.5 Programs and Manuals

5.5.12 Safety Function Determination Program (SFDP) (continued)

A required system redundant to support system(s) for the supported systems described in 6.1 and 6.2 above is also inoperable.

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

Insert 5.5.12

B

(31)

INSERT 5.5.12

5.5.12 Primary Containment Leakage Rate Testing Program

The Primary Containment Leakage Rate Testing Program shall establish the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995, as modified by the following exception: Compensation for flow meter inaccuracies in excess of those specified in ANSI/ANS 56.8-1994 will be accomplished by increasing the actual instrument reading by the amount of the full scale inaccuracy when assessing the effect of local leak rates against the criteria established in Specification 5.5.12.a.

The peak calculated primary containment internal pressure for the design basis loss of coolant accident, P_a, is 38 psig.

The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 0.5% of primary containment air weight per day.

(B)

Leakage rate acceptance criteria are:

a. Primary containment leakage rate acceptance criterion is ≤ 1.0 L_a. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are < 0.60 L_a for the Type B and Type C tests (except for main steam isolation valves) and < 0.75 L_a for Type A tests;

b. Primary containment air lock testing acceptance criteria are:

   1) Overall primary containment air lock leakage rate is ≤ 0.05 L_a when tested at $\geq P_a$; and

   2) For each door, leakage rate is ≤ 0.025 L_a when pressurized to ≥ 10 psig.

The provisions of SR 3.0.3 are applicable to the Primary Containment Leakage Rate Testing Program.

5.6 Reporting Requirements

5.6.2 Annual Radiological Environmental Operating Report (continued)

(ODCM), and in 10 CFR 50, Appendix I, Sections IV.B.2, IV.B.3, and IV.C.

The Annual Radiological Environmental Operating Report shall include the results of analyses of all radiological environmental samples and of all environmental radiation measurements taken during the period pursuant to the locations specified in the table and figures in the ODCM, as well as summarized and tabulated results of these analyses and measurements in the format of the table in the Radiological Assessment Branch Technical Position, Revision 1, November 1979. [The report shall identify the TLD results that represent collocated dosimeters in relation to the NRC TLD program and the exposure period associated with each result.] In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting and explaining the reasons for the missing results. The missing data shall be submitted in a supplementary report as soon as possible.

5.6.3 Radioactive Effluent Release Report

NOTE

A single submittal may be made for a multiple unit station. The submittal should combine sections common to all units at the station; however, for units with separate radwaste systems, the submittal shall specify the releases of radioactive material from each unit.

The Radioactive Effluent Release Report covering the operation of the unit shall be submitted in accordance with 10 CFR 50.36a. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be consistent with the objectives outlined in the ODCM and Process Control Program and in conformance with 10 CFR 50.36a and 10 CFR 50, Appendix I, Section IV.B.1.

5.6.4 Monthly Operating Reports

Routine reports of operating statistics and shutdown experience, including documentation of all challenges to the safety/relief

(continued)

(30)

INSERT 5.7

As provided in paragraph 20.1601(c) of 10 CFR Part 20, the following controls shall be applied to high radiation areas in place of the controls required by paragraph 20.1601(a) and (b) of 10 CFR Part 20.

(30) INSERT 5.7.1

5.7.1 High Radiation Areas with Dose Rates not Exceeding 1.0 rem/hour (at 30 centimeters from the radiation sources or from any surface penetrated by the radiation)

a. Each entryway to such an area shall be barricaded and conspicuously posted as a high radiation area. Such barricades may be opened as necessary to permit entry or exit of personnel or equipment. (B)

b. Access to, and activities in, each such area shall be controlled by means of a Radiation Work Permit (RWP) or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures (e.g., health physics technicians) and personnel continuously escorted by such individuals may be exempted from the requirement for an RWP or equivalent while performing their assigned duties provided that they are following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess: (B)

1. A radiation monitoring device that continuously displays radiation dose rates in the area ("radiation monitoring and indicating device");

2. A radiation monitoring device that continuously integrates the radiation dose rates in the area and alarms when the device's dose alarm setpoint is reached ("alarming dosimeter"), with an appropriate alarm setpoint;

(30) INSERT 5.7.1
(continued)

3. A radiation monitoring device that continuously transmits dose rate and cumulative dose to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area; or

4. A self-reading dosimeter and,

   (a) Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual at the work site, qualified in radiation protection procedures, equipped with a radiation monitoring and indicating device who is responsible for controlling personnel radiation exposure within the area, or

   (b) Be under the surveillance, as specified in the RWP or equivalent, while in the area, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area.

e. Except for individuals qualified in radiation protection procedures, entry into such areas shall be made only after dose rates in the area have been established and entry personnel are knowledgeable of them. (A)

(30) INSERT 5.7.2

5.7.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour (at 30 centimeters from the radiation source or from any surface penetrated by the radiation), but less than 500 rads/hour (at 1 meter from the radiation source or from any surface penetrated by the radiation)

a. Each entryway to such an area shall be conspicuously posted as a high radiation area and shall be provided with a locked door, gate, or guard that prevents unauthorized entry, and in addition:

1. All such door and gate keys shall be maintained under the administrative control of the Shift Manager or Health Physics supervision on duty; and

2. Doors and gates shall remain locked or guarded except during periods of personnel entry or exit.

b. Access to, and activities in, each such area shall be controlled by means of an RWP or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures may be exempted from the requirement for an RWP or equivalent while performing radiation surveys in such areas provided that they are following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess: (B)

1. An alarming dosimeter with an appropriate alarm setpoint;

2. A radiation monitoring device that continuously transmits dose rate and cumulative dose to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area with the means to communicate with and control every individual in the area; (B)

(30) INSERT 5.7.2
(continued)

3. A self-reading dosimeter and,

   (a) Be under the surveillance, as specified in the RWP or equivalent, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring and indicating device who is responsible for controlling personnel exposure within the area, or

   (b) Be under the surveillance, as specified in the RWP or equivalent, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with and control every individual in the area; or

4. A radiation monitoring and indicating device in those cases where the options of Specification 5.7.2.d.2 and 5.7.2.d.3, above, are impractical or determined to be inconsistent with the "As Low As is Reasonably Achievable" principle.

(B)

e. Except for individuals qualified in radiation protection procedures, entry into such areas shall be made only after dose rates in the area have been established and entry personnel are knowledgeable of them.

f. Such individual areas that are within a larger area that is controlled as a high radiation area, where no enclosure exists for purpose of locking and where no enclosure can reasonably be constructed around the individual area need not be controlled by a locked door or gate, but shall be barricaded and conspicuously posted as a high radiation area, and a conspicuous, clearly visible flashing light shall be activated at the area as a warning device.

17. (continued)

of ESF filter ventilation systems). The other ITS programs (e.g., IST Program, Specification 5.5.6) provide the proper words, assuming that the program is already established. Therefore, these changes are bringing the VFTP and the Diesel Fuel Oil Testing Program in line with the words of the other programs.

18. The current licensing basis Surveillance Frequencies have been provided. In addition, for clarity, the NUREG discussion concerning the provisions of SR 3.0.2 and SR 3.0.3 have been moved from the end of this Specification to just after the discussion of the Frequencies, since it applies only to the Frequencies.

19. The Temperature requirement has been deleted to be consistent with current licensing basis. In addition, since the temperature requirement has been deleted, the relative humidity requirement has been editorially changed to be consistent with the words used in proposed Specifications 5.5.7.a, 5.5.7.b, and 5.5.7.d.

20. Proposed Specification 5.5.7.d demonstrates that the pressure drop across the HEPA filters and charcoal adsorbers is less than the specified pressure drop when tested at the specified system flow rate. The referenced methods for performing the test, Regulatory Guide 1.52 and ASME N510-1989 do not provide the methods for performing this test. As a result, these test method references have been deleted. In addition, WNP-2 does not currently require prefilter pressure drop tests, thus the prefilter requirement has also been deleted. (B)

21. The provisions in the NUREG for Waste Gas Systems are for PWRs and not applicable to WNP-2. Quantities of radioactivity contained in all outdoor liquid radwaste tanks meeting the conditions of proposed Specification 5.5.8 are determined in accordance with the specified Surveillance Program (proposed Specification 5.5.8.b). Therefore, the sentence in the introductory paragraph is not necessary to specify a method to determine liquid radwaste quantities.

22. The requirement to limit oxygen in the Main Condenser Offgas Treatment System has been deleted consistent with current licensing basis.

23. These provisions are only for PWRs and are not applicable for WNP-2. Due to this deletion, the following Specification has been renumbered.

24. The existing wording that the Diesel Fuel Oil Testing Program be "in accordance with applicable ASTM Standards" has been revised to "in accordance with procedures based on applicable ASTM Standards." This change is administrative in nature and provides the capability for justified variances between the ASTM Standards and the implementing procedures. For example, one variance includes the use of new glassware for determining kinematic viscosity versus requiring the ASTM requirement to use glassware that has been cleaned with chromic acid.

24. (continued)

In addition, the words "in accordance with ASTM D-2276 Method A-2 or A-3" in Specification 5.5.9.c have been deleted since they are redundant to the words in Specification 5.5.9.

25. The Fuel Oil Testing Program requirements have been modified to be consistent with current licensing basis.

26. These words have been added for clarity.

27. This requirement has been deleted in accordance with the guidance of Generic Letter 94-01. WNP-2 will implement a maintenance program for monitoring and maintaining diesel generator performance in accordance with the provisions of the maintenance rule and consistent with the guidance of Regulatory Guide 1.160. The commitment will be implemented within 90 days of issuance of the ITS license amendment. This change is consistent with BWR STS-09, C.1, which allows relocation of the Table provided the requirements of the Reviewer's Note added to this page are met. In addition, the following Specification was renumbered to reflect this deletion.

28. The acronym "PAM" has been defined, consistent with the format of the ITS, since it is the first use of this term in this Specification. The term "Instrumentation" has also been added for clarity. In addition, the term "Special Report" has been replaced by "report" since LCO 3.3.3.1 does not refer to this as a Special Report, and this report is not under the old (revision 0) header of "Special Reports."

29. The proper Condition has been provided.

30. The High Radiation Area Specification has been significantly changed to be consistent with those in the draft NRC Generic Letter on Technical Specification changes to reflect the revisions to 10 CFR 20. Minor editorial changes to the guidance provided in the draft NRC Generic Letter were made for consistency with plant specific terminology or for clarity.

31. A Primary Containment Leakage Rate Testing Program has been added consistent with the letter from C. I. Grimes to D. J. Modeen, dated November 2, 1995. This letter transmitted the draft ITS pages marked up to reflect Appendix J, Option B testing requirements.

BASES

APPLICABLE SAFETY ANALYSES

2.1.1.3 Reactor Vessel Water Level (continued)

active irradiated fuel to provide a point that can be monitored and to also provide adequate margin for effective action.

SAFETY LIMITS

The reactor core SLs are established to protect the integrity of the fuel clad barrier to the release of radioactive materials to the environs. SL 2.1.1.1 and SL 2.1.1.2 ensure that the core operates within the fuel design criteria. SL 2.1.1.3 ensures that the reactor vessel water level is greater than the top of the active irradiated fuel in order to prevent elevated clad temperatures and resultant clad perforations.

APPLICABILITY

SLs 2.1.1.1, 2.1.1.2, and 2.1.1.3 are applicable in all MODES.

SAFETY LIMIT VIOLATIONS

2.2.1

If any SL is violated, the NRC Operations Center must be notified within 1 hour, in accordance with 10 CFR 50.72 (Ref. 4).

2.2.2

Exceeding an SL may cause fuel damage and create a potential for radioactive releases in excess of 10 CFR 100, "Reactor Site Criteria," limits (Ref. 5). Therefore, it is required to insert all insertable control rods and restore compliance with the SL within 2 hours. The 2 hour Completion Time ensures that the operators take prompt remedial action and the probability of an accident occurring during this period is minimal.

(continued)

BASES

SAFETY LIMIT VIOLATIONS (continued)

2.2.3

If any SL is violated, the [senior management of the nuclear plant and the utility Vice President-Nuclear Operations] shall be notified within 24 hours. The 24 hour period provides time for plant operators and staff to take the appropriate immediate action and assess the condition of the unit before reporting to the appropriate utility management.

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2.2.4

If any SL is violated, a Licensee Event Report shall be prepared and submitted within 30 days to the NRC in accordance with 10 CFR 50.73 [Ref. 6]. A copy of the report shall also be provided to the [senior management of the nuclear plant and the utility Vice President-Nuclear Operations].

2.2.5

If any SL is violated, restart of the unit shall not commence until authorized by the NRC. This requirement ensures the NRC that all necessary reviews, analyses, and actions are completed before the unit begins its restart to normal operation.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10.
2. NEDE-24011-P-A, (latest approved revision).
3. XN-NF-524(A), Revision 1, November 1983.
4. ~~10 CFR 50.72.~~
5. ~~10 CFR 100.~~
6. ~~10 CFR 50.73.~~

TSTF-05

ANF-524 (P)(A), Revision 2, including Supplements 1 and 2, November 1990.

ANF-1125 (P)(A), Revision 0, including supplements 1 and 2, April 1990.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The RCS safety/relief valves and the Reactor Protection System Reactor Vessel Steam Dome Pressure—High Function have settings established to ensure that the RCS pressure SL will not be exceeded.

The RCS pressure SL has been selected such that it is at a pressure below which it can be shown that the integrity of the system is not endangered. The reactor pressure vessel is designed to ASME, Boiler and Pressure Vessel Code, Section III, ~~{~~1971 Edition~~}~~, including Addenda through the ~~(winter of 1972)~~ summer of 1971 (Ref. 5), which permits a maximum pressure transient of 110%, 1375 psig, of design pressure 1250 psig. The SL of 1325 psig, as measured in the reactor steam dome, is equivalent to 1375 psig at the lowest elevation of the RCS. The RCS is designed to ASME Code, Section III, ~~1974~~ 1971 Edition (Ref. ~~6~~ 5), for the reactor recirculation piping, which permits a maximum pressure transient of ~~110%~~ 125% of design pressures of 1250 psig for suction piping and ~~1650~~ 1550 psig for discharge piping. The RCS pressure SL is selected to be the lowest transient overpressure allowed by the applicable codes.

SAFETY LIMITS

The maximum transient pressure allowable in the RCS pressure vessel under the ASME Code, Section III, is 110% of design pressure. The maximum transient pressure allowable in the RCS piping, valves, and fittings is ~~110%~~ 125% of design pressures of 1250 psig for suction piping and ~~1650~~ 1550 psig for discharge piping. The most limiting of these allowances is the 110% of ~~the suction piping~~ design pressure; therefore, the SL on maximum allowable RCS pressure is established at 1325 psig as measured at the reactor steam dome.

APPLICABILITY

SL 2.1.2 applies in all MODES.

SAFETY LIMIT VIOLATIONS

TSTF-05

2.2.1

If any SL is violated, the NRC Operations Center must be notified within 1 hour, in accordance with 10 CFR 50.72 (Ref. 7).

B

(continued)

BASES

SAFETY LIMIT VIOLATIONS (continued)

2.2.2 (7)

Exceeding the RCS pressure SL may cause ~~immediate~~ RCS failure and create a potential for radioactive releases in excess of 10 CFR 100, "Reactor Site Criteria," limits (Ref. 4). Therefore, it is required to insert all insertable control rods and restore compliance with the SL within 2 hours. The 2 hour Completion Time ensures that the operators take prompt remedial action and also assures that the probability of an accident occurring during this period is minimal.

TSTF-05

2.2.3

If any SL is violated, the appropriate [senior management of the nuclear plant and the utility Vice President-Nuclear Operations] shall be notified within 24 hours. The 24 hour period provides time for plant operators and staff to take the appropriate immediate action and assess the condition of the unit before reporting to the appropriate utility management.

TSTF-05

2.2.4

If any SL is violated, a Licensee Event Report shall be prepared and submitted within 30 days to the NRC in accordance with 10 CFR 50.73 (Ref. 8). A copy of the report shall also be provided to the [senior management of the nuclear plant and the utility Vice President-Nuclear Operations].

2.2.5

If any SL is violated, restart of the unit shall not commence until authorized by the NRC. This requirement ensures the NRC that all necessary reviews, analyses, and actions are completed before the unit begins its restart to normal operation.

(continued)

BASES (continued)

REFERENCES

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

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

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

4. 10 CFR 100.

5. ASME, Boiler and Pressure Vessel Code, ~~[~~1971 Edition~~]~~, Addenda, winter of 1972. Summer of 1971

~~6. ASME, Boiler and Pressure Vessel Code, [1974 Edition].~~

7. 10 CFR 50.72.

8. 10 CFR 50.73.

TSTF-05

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

1. The word significant has been deleted since the WNP-2 Safety Limits are set to ensure no fuel damage occurs.

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

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

4. WNP-2 does not use GE fuel. As a result, the Bases discussions for GE fuel Safety Limits have been deleted.

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

6. Typographical/grammatical error corrected.

7. Editorial change made for clarity.

B

BASES

SR 3.0.2 (continued)

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. An example of where SR 3.0.2 does not apply is a Surveillance with a Frequency of "in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions." The requirements of regulations take precedence over the TS. The TS cannot in and of themselves extend a test interval specified in the regulations. Therefore, there is a Note in the Frequency stating, "SR 3.0.2 is not applicable."

9

Insert SR3.0.2

B

As stated in SR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per..." basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required Action, whether it is a particular Surveillance or some other remedial action, is considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner.

The provisions of SR 3.0.2 are not intended to be used repeatedly merely as an operational convenience to extend Surveillance intervals (other than those consistent with refueling intervals) or periodic Completion Time intervals beyond those specified.

SR 3.0.3

SR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified Frequency. A delay period of up to 24 hours or up to the limit of the specified Frequency, whichever is less, applies from the point in time it is discovered that the Surveillance has

(continued)

(9)

INSERT SR 3.0.2

Therefore, when a test interval is specified in the regulations, the test interval cannot be extended by the TS, and the SR includes a Note in the Frequency stating, "SR 3.0.2 is not applicable." (B)

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

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

2. Typographical/grammatical error corrected.

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

4. The correct LCO title and fuel pool description has been provided. The WNP-2 Spent Fuel Storage Pool design is similar to that described in the BWR/4 Improved Technical Specifications, NUREG-1433, Revision 1; thus the words have been changed to be consistent with the wording in NUREG-1433, Revision 1.

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

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

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

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

9. Changes have been made to reflect those changes made to the Specifications in Section 3.6. (B)

BASES

LCO (continued)

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

For Siemens fuel, MFDLRX is the equivalent of MFLPD.

MFLPD is the ratio of the limiting LHGR to the LHGR limit for the specific bundle type. As power is reduced, if the design power distribution is maintained, MFLPD is reduced in proportion to the reduction in power. However, if power peaking increases above the design value, the MFLPD is not reduced in proportion to the reduction in power. Under these conditions, the APRM gain is adjusted upward or the APRM ~~flow biased scram setpoints~~ are reduced accordingly. When the reactor is operating with peaking less than the design value, it is not necessary to modify the APRM ~~flow biased scram setpoints~~. Adjusting the APRM gain or modifying the ~~setpoints~~ is equivalent to maintaining MFLPD less than or equal to FRTP, as stated in the LCO.

Flow Biased Simulated Thermal Power-High Function Allowable Value

For compliance with LCO Item b (APRM ~~setpoint adjustment~~ modification) or Item c (APRM gain adjustment), only APRMs required to be OPERABLE per LCO 3.3.1.1, ~~"Reactor Protection System (RPS) Instrumentation,"~~ Function 2.b are required to be adjusted. In addition, each APRM may be allowed to have its gain or ~~setpoints~~ Allowable Value adjusted independently of other APRMs that are having their gain or ~~setpoints~~ modified or Allowable Value adjusted.

APPLICABILITY

The MFLPD limit, APRM gain adjustment, or APRM ~~flow biased scram and associated setdowns~~ is provided to ensure that the fuel cladding integrity SL and the fuel cladding 1% plastic strain limit are not violated during design basis transients. As discussed in the Bases for LCO 3.2.1 and LCO 3.2.2, sufficient margin to these limits exists below 25% RTP and, therefore, these requirements are only necessary when the plant is operating at ≥ 25% RTP.

ACTIONS

A.1

If the APRM gain or ~~setpoints~~ are not within limits while the MFLPD has exceeded FRTP, the margin to the fuel cladding integrity SL and the fuel cladding 1% plastic strain limit

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

The OPERABILITY of scram pilot valves and associated solenoids, backup scram valves, and SDV valves, described in the Background section, are not addressed by this LCO.

The individual Functions are required to be OPERABLE in the MODES specified in the Table that may require an RPS trip to mitigate the consequences of a design basis accident or transient. To ensure a reliable scram function, a combination of Functions is required in each MODE to provide primary and diverse initiation signals.

RPS is required to be OPERABLE in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies. Control rods withdrawn from a core cell containing no fuel assemblies do not affect the reactivity of the core and therefore are not required to have the capability to scram. Provided all other control rods remain inserted, the RPS function is not required. In this condition, the required SDM (LCO 3.1.1) and refuel position one-rod-out interlock (LCO 3.9.2) ensure that no event requiring RPS will occur. During normal operation in MODES 3 and 4, all control rods are fully inserted and the Reactor Mode Switch Shutdown Position control rod withdrawal block (LCO 3.3.2.1) does not allow any control rod to be withdrawn. Under these conditions, the RPS function is not required to be OPERABLE.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

1.a. Intermediate Range Monitor (IRM) Neutron Flux–High

The IRMs monitor neutron flux levels from the upper range of the source range monitors (SRMs) to the lower range of the average power range monitors (APRMs). The IRMs are capable of generating trip signals that can be used to prevent fuel damage resulting from abnormal operating transients in the intermediate power range. In this power range, the most significant source of reactivity change is due to control rod withdrawal. The IRM provides diverse protection for the rod withdrawal limiter (RWL), which monitors and controls

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.6 and SR 3.3.1.1.9 (continued)

channel(s) that are required in the current MODE or condition should be declared inoperable.

A Frequency of 7 days is reasonable based on engineering judgment and the reliability of the IRMs and APRMs.

SR 3.3.1.1.8

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the APRM System. The 1130 MWD/T Frequency is based on operating experience with LPRM sensitivity changes.

SR 3.3.1.1.9 and SR 3.3.1.1.12

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the ~~entire~~ channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The 92 day Frequency of SR 3.3.1.1.9 is based on the reliability analysis of Reference 9.A.

Insert + SR 3.3.1.1.8 from pages B 3.3-25 and B 3.3-26.

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

SR 3.3.1.1.10

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.1.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.2.1 (continued)

instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. As specified in the Surveillance, a CHANNEL CHECK is only required for those channels that are normally energized.

The Frequency is based upon plant operating experience that demonstrates channel failure is rare.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the surveillance were performed with the reactor at power.

SR 3.3.3.2.2

SR 3.3.3.2.2 verifies each required Remote Shutdown System transfer switch and control circuit performs the intended function. This verification is performed from the remote shutdown panel and locally, as appropriate. Operation of the equipment from the remote 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 plant can be placed and maintained in MODE 3 from the remote shutdown panel and the local control stations. However, this Surveillance is not required to be performed only during a plant outage. Operating experience demonstrates that Remote Shutdown System control channels usually pass the Surveillance when performed at the 18 month Frequency.

shutdown panel or alternate remote

and alternate

and alternate

24

SR 3.3.3.2.3 and SR 3.3.3.2.3

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. The test verifies the channel responds to measured parameter values with the necessary range and accuracy. of SR 3.3.3.2.2

The 18 month Frequency is based upon operating experience and is consistent with the typical industry refueling cycle.

The 24 month Frequency of SR 3.3.3.2.3 is based upon operating experience and engineering judgement.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.1.3

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be not within its required Allowable Value specified in Table 3.3.5.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analyses. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than the setting accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of Reference 4.

SR 3.3.5.1.4 and SR 3.3.5.1.5

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

The Frequencies of SR 3.3.5.1.4, and SR 3.3.5.1.5 are based upon the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.5.1.5 is based upon the assumption of an [18] month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.5.1.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.5.1, LCO 3.5.2, LCO 3.8.1, and LCO 3.8.2 overlaps this Surveillance to provide complete testing of the assumed safety function.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1.6 (continued)

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 unplanned transients if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the ~~[18]~~ month Frequency.

SR 3.3.5.1.7

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. Response time testing acceptance criteria are included in Reference 5.

ECCS RESPONSE TIME tests are conducted on an [18] month STAGGERED TEST BASIS. The [18] month Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent.

REFERENCES

1. FSAR, Section ~~[5.2]~~.
2. FSAR, Section ~~[6.3]~~.
3. FSAR, Chapter ~~[15]~~.
4. FSAR, Section 15.F.6.
7. NEDC-30936-P-A, "BWR Owners' Group Technical Specification Improvement Analyses for ECCS Actuation Instrumentation, Part 2," December 1988.
2. ~~5. FSAR, Section [6.3], Table [6.3-2].~~
5. NEDC-32115P, "Washington Public Power Supply System Nuclear Project 2, SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," July 1993.
6. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

BASES

ACTIONS (continued)

A.1

With one or more channels of a Function inoperable, the Function may not be capable of performing the intended function. Therefore, only 1 hour is allowed to restore the inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the channel in trip would result in a bus transfer and 2 DG initiation), Condition B must be entered and its Required Action taken.

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

B.1, B.2.1, and B.2.2

If any Required Action and associated Completion Time is not met, the associated Function may not be capable of performing the intended function. Therefore, the associated DG(s) are declared inoperable immediately. This requires entry into applicable Conditions and Required Actions of LCO 3.8.1 and LCO 3.8.2, which provide appropriate actions for the inoperable DG(s). B

(Required Action B.1)

Insert B.2.1 and B.2.2

SURVEILLANCE REQUIREMENTS 2

As noted at the beginning of the SRs, the SRs for each LOP Instrumentation Function are located in the SRs column of Table 3.3.8.1-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 2 hours provided the associated Function maintains DG 2 initiation capability. Upon completion of the Surveillance,

Initiation capability is maintained provided the following can be initiated by the function (i.e., loss of Voltage and Degraded Voltage) for two of the three DGs and 4.16 kV ESF buses: DG start, disconnect from the offsite power source, transfer to the alternate offsite power source, if available, DG output breaker closure, and load shed,

(continued)

(8)

INSERT B.2.1 and B.2.2

Alternately, for Functions 1.c and 1.d only, the TR-B loss of voltage instrumentation, the offsite circuit supply breaker to the associated 4.16 kV ESF bus must be opened immediately (Required Action B.2.1) and the associated offsite circuit declared inoperable immediately (Required Action B.2.2). These alternate Required Actions also provide appropriate compensatory measures since the TR-B loss of voltage instrumentation only affects the loss of voltage trip capability of the alternate offsite circuit.

(B)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.1.2 and SR 3.3.8.1.3

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

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency is based on the assumption of an 18 month or 24 month calibration interval, as applicable, in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.8.1.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required actuation logic for a specific channel. The system functional testing performed in LCO 3.8.1 and LCO 3.8.2 overlaps this Surveillance to provide complete testing of the assumed safety functions.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. FSAR, Figure [ ], Section 8.3.1.1.1.
2. FSAR, Section 15.2.
3. FSAR, Section 6.3.
4. FSAR, Chapter 15.
5. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58FR39132).

BASES

BACKGROUND (continued)

circuit breakers has an associated independent set of Class 1E overvoltage, undervoltage, and underframequency sensing logic. Together, a circuit breaker and its sensing logic constitute an electric power monitoring assembly. If the output of the MG set or the alternate power supply exceeds the predetermined limits of overvoltage, undervoltage, or underfrequency, a trip coil driven by this logic circuitry opens the circuit breaker, which removes the associated power supply from service.

APPLICABLE SAFETY ANALYSES

RPS electric power monitoring is necessary to meet the assumptions of the safety analyses by ensuring that the equipment powered from the RPS buses can perform its intended function. RPS electric power monitoring provides protection to the RPS and other systems that receive power from the RPS buses, by disconnecting the RPS from the power supply under specified conditions that could damage the RPS bus powered equipment.

RPS electric power monitoring satisfies Criterion 3 of the NRC Policy Statement. (Ref. 2)

LCO

The OPERABILITY of each RPS electric power monitoring assembly is dependent upon the OPERABILITY of the overvoltage, undervoltage, and underfrequency logic, as well as the OPERABILITY of the associated circuit breaker. Two electric power monitoring assemblies are required to be OPERABLE for each inservice power supply that supports equipment required to be OPERABLE (i.e., if the inservice power supply is not supporting any equipment required to be OPERABLE by Technical Specifications, then the associated electric power monitoring assemblies are not required to be OPERABLE). This provides redundant protection against any abnormal voltage or frequency conditions to ensure that no single RPS electric power monitoring assembly failure can preclude the function of the RPS bus powered components. Each inservice electric power monitoring assembly's trip logic setpoints are required to be within the specific Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each RPS electric power monitoring assembly trip logic (refer to SR 3.3.8.2.2). Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less

(continued)

BASES

LCO (continued)

conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., overvoltage), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip, and/) changes state. The analytic limits are derived from the limiting values of the process parameters, obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined, accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

The Allowable Values for the instrument settings are based on the RPS providing ≥ 57 Hz, 120 V ± 10% (to all equipment), and 115 V ± 10 V (to scram and MSIV solenoids). The most limiting voltage requirement and associated line losses determines the settings of the electric power monitoring instrument channels. The settings are calculated based on the loads on the buses and RPS MG set or alternate power supply being 120 VAC and 60 Hz.

APPLICABILITY

The operation of the RPS electric power monitoring assemblies is essential to disconnect the RPS bus powered components from the MG set or alternate power supply during abnormal voltage or frequency conditions. Since the degradation of a nonclass 1E source supplying power to the RPS bus can occur as a result of any random single failure, the OPERABILITY of the RPS electric power monitoring assemblies is required when the RPS bus powered components are required to be OPERABLE. This results in the RPS Electric Power Monitoring System OPERABILITY being required in MODES 1, 2, and 3, and MODES 4 and 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, or with both residual heat removal (RHR) shutdown cooling isolation valves open, and MODES

(continued)

BASES

ACTIONS

B.1 (continued)

OPERABLE assemblies may then be used to power one RPS bus. The 1 hour Completion Time is sufficient for the plant operations personnel to take corrective actions and is acceptable because it minimizes risk while allowing time for restoration or removal from service of the electric power monitoring assemblies.

Alternately, if it is not desired to remove the power supply(s) from service (e.g., as in the case where removing the power supply(s) from service would result in a scram or isolation), Condition C or D, as applicable, must be entered and its Required Actions taken.

C.1 and C.2

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 1, 2, or 3, a plant shutdown must be performed. This places the plant in a condition where minimal equipment, powered through the inoperable RPS electric power monitoring assembly(s), is required and ensures that the safety function of the RPS (e.g., scram of control rods) is not required. The plant shutdown is accomplished by placing the plant in MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

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

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 4 or 5, with any control rod withdrawn from a core cell containing one or more fuel assemblies, with both RHR shutdown cooling valves open, the operator must immediately initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies (Required Action D.1). This Required Action results in the least reactive condition for the reactor core and ensures that the safety function of the RPS (e.g., scram of control rods) is not required.

Copy to INSERT E.1a, next page

Suction isolation

move to Insert E.1b, next page

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

In addition, action must be immediately initiated to either restore one electric power monitoring assembly to OPERABLE status for the inservice power source supplying the required instrumentation powered from the RPS bus (Required Action D.1) or to isolate the RHR Shutdown Cooling System (Required Action D.2). Required Action D.1 is provided because the RHR Shutdown Cooling System may be needed to provide core cooling. All actions must continue until the applicable Required Actions are completed.

Insert SR

E.1

Insert E.1a, from previous page

Insert E.1b, from previous page

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.1

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

As noted in the Surveillance, the CHANNEL FUNCTIONAL TEST is only required to be performed while the plant is in a condition in which the loss of the RPS bus will not jeopardize steady state power operation (the design of the system is such that the power source must be removed from service to conduct the Surveillance). The 24 hours is intended to indicate an outage of sufficient duration to allow for scheduling and proper performance of the Surveillance. The 184 day Frequency and the Note in the Surveillance are based on guidance provided in Generic Letter 91-09 (Ref. 2).

SR 3.3.8.2.2 and SR 3.3.8.2.3

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.2 and SR 3.3.8.2.3 (continued)

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

SR 3.3.8.2.4

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

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

REFERENCES

1. FSAR, Section 8.3.1.1

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

2. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

BASES

ACTIONS

A.2 E.1 and F.1 (5) (continued)

flow mismatches occur, low flow or reverse flow can occur in the low flow loop jet pumps, causing vibration of the jet pumps. If zero or reverse flow is detected, the condition should be alleviated by changing flow control valve position to re-establish forward flow or by tripping the pump

move to pwr. page

B.1 (G-1) (5)

while in a Region other than Region A of the power-to-flow MAP (5)

With no recirculation loops in operation, or the Required Action and associated Completion Time of Condition B not met, the unit is required to be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. In this condition, the recirculation loops are not required to be operating because of the reduced severity of DBAs and minimal dependence on the recirculation loop coastdown characteristics. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. (E) (5)

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

,7595 x 10^6 lbm/hr (3)

This SR ensures the recirculation loop flows are within the allowable limits for mismatch. At low core flow (i.e., < {70}% of rated core flow), the MCPR requirements provide larger margins to the fuel cladding integrity Safety Limit such that the potential adverse effect of early boiling transition during a LOCA is reduced. A larger flow mismatch can therefore be allowed when core flow is < {70}% of rated core flow. The recirculation loop jet pump flow, as used in this Surveillance, is the summation of the flows from all of the jet pumps associated with a single recirculation loop.

(6) (6) (5)

recirculation loop drive

The mismatch is measured in terms of percent of rated core flow. If the flow mismatch exceeds the specified limits, the loop with the lower flow is considered inoperable. This SR is not required when both loops are not in operation since the mismatch limits are meaningless during single loop or natural circulation operation. The Surveillance must be

not in operation However, for the purpose of performing SR 3.4.1.2, the flow rate of both loops shall be used) (4)

(continued)

BASES

LCO (continued)

b. Unidentified LEAKAGE

Five gpm of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the drywell atmosphere monitoring and drywell sump level monitoring and drywell air cooler condensate flow rate monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB.

c. Total LEAKAGE

The total LEAKAGE limit is based on a reasonable minimum detectable amount. The limit also accounts for LEAKAGE from known sources (identified LEAKAGE). Violation of this LCO indicates an unexpected amount of LEAKAGE and, therefore, could indicate new or additional degradation in an RCPB component or system.

d. Unidentified LEAKAGE Increase

An unidentified LEAKAGE increase of > 2 gpm within the previous 24 hour period indicates a potential flaw in the RCPB and must be quickly evaluated to determine the source and extent of the LEAKAGE. The increase is measured relative to the steady state value; temporary changes in LEAKAGE rate as a result of transient conditions (e.g., startup) are not considered. As such, the 2 gpm increase limit is only applicable in MODE 1 when operating pressures and temperatures are established. Violation of this LCO could result in continued degradation of the RCPB.

APPLICABILITY In MODES 1, 2, and 3, the RCS operational LEAKAGE LCO applies because the potential for RCPB LEAKAGE is greatest when the reactor is pressurized.

In MODES 4 and 5, RCS operational LEAKAGE limits are not required since the reactor is not pressurized and stresses in the RCPB materials and potential for LEAKAGE are reduced.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

manual, deactivated, automatic, or check valve within 4 hours. Required Action A.1 and Required Action A.2 are modified by a Note stating that the valves used for isolation must meet the same leakage requirements as the PIVs and must be on the RCPB [or the high pressure portion of the system.]

Four hours provides time to reduce leakage in excess of the allowable limit and to isolate the flow path if leakage cannot be reduced while corrective actions to reseat the leaking PIVs are taken. The 4 hours allows time for these actions and restricts the time of operation with leaking valves, and

Required Action A.2 specifies that the double isolation barrier of two valves be restored by closing another valve qualified for isolation or restoring one leaking PIV. The 72 hour Completion Time after exceeding the limit considers the time required to complete the Required Action, the low probability of a second valve failing during this time period, and the low probability of a pressure boundary rupture of the low pressure ECCS piping when overpressurized to reactor pressure (Ref. 9).

B.1 and B.2

If leakage cannot be reduced or the system isolated, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. This action may reduce the leakage and also reduces the potential for a LOCA outside the containment. The Completion Times are reasonable, based on operating experience, to achieve the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.[6].1

Performance of leakage testing on each RCS PIV is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit of 0.5 gpm

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.1 (continued)

per inch of nominal valve diameter up to 5 gpm maximum applies to each valve. Leakage testing requires a stable pressure condition. For the two PIVs in series, the leakage requirement applies to each valve individually and not to the combined leakage across both valves. If the PIVs are not individually leakage tested, one valve may have failed completely and not be detected if the other valve in series meets the leakage requirement. In this situation, the protection provided by redundant valves would be lost.

The 18 month Frequency required by the Inservice Testing Program is within the ASME Code, Section XI, Frequency requirement and is based on the need to perform this Surveillance under the conditions that apply during an outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

Therefore, this SR is modified by a Note that states the leakage Surveillance is not required to be performed in MODE 3. Entry into MODE 3 is permitted for leakage testing at high differential pressures with stable conditions not possible in the lower MODES.

As stated in the LCO Section of the Bases, the test pressure may be at a lower pressure than the maximum pressure differential (at the RCS maximum pressure of 1035 psig) provided the observed leakage rate is adjusted in accordance with Reference 4. The actual test pressure shall be 2935 psig, 1 and 2

REFERENCES

1. 10 CFR 50.2.
2. 10 CFR 50.55a(c).
3. 10 CFR 50, Appendix A, GDC 55.
4. ASME, Boiler and Pressure Vessel Code, Section XI.
5. NUREG-0677, May 1980.
6. FSAR, Section [ ].
7. NEDC-31339, November 1986.

"The Probability of Intersystem LOCA: Impacts due to leak Testing and Operational Changes,"

Licensee Controlled Specifications Manual

"BWR Owners Group Assessment of Emergency Core Cooling System Pressurization in Boiling Water Reactors,"

7. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58FR39132).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.0.1 (continued)

properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

SR 3.4.0.2

This SR requires the performance of a CHANNEL FUNCTIONAL TEST of the required RCS leakage detection instrumentation. The test ensures that the monitors can perform their function in the desired manner. The test also verifies the alarm setpoint and relative accuracy of the instrument string. The Frequency of 31 days considers instrument reliability, and operating experience has shown it proper for detecting degradation.

SR 3.4.0.3

This SR requires the performance of a CHANNEL CALIBRATION of the required RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside the drywell. The Frequency of ~~18~~ months is a typical refueling cycle and considers channel reliability. Operating experience has proven this Frequency is acceptable.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 30.
2. Regulatory Guide 1.45, May 1973.
3. FSAR, Section ~~5.2.5~~ 5.5.
4. GEAP-5620, April 1968.
5. NUREG-75/067, October 1975.
6. FSAR, Section 5.2.5.5.3.
7. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58FR39132).

"Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactors,"

"Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flaws,"

BASES

ACTIONS

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

failure in the OPERABLE subsystem could result in reduced RHR shutdown cooling capability. Therefore an alternate method of decay heat removal must be provided.

With both RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities.

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

However, due to the potentially reduced reliability of the alternate methods of decay heat removal, it is also required to reduce the reactor coolant temperature to the point where MODE 4 is entered.

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

With no RHR shutdown cooling subsystem and no recirculation pump in operation, except as is permitted by LCO Note 1, reactor coolant circulation by the RHR shutdown cooling subsystem or one recirculation pump must be restored without delay.

Until RHR or recirculation pump operation is re-established, an alternate method of reactor coolant circulation must be placed into service. This will provide the necessary circulation for monitoring coolant temperature. The 1 hour Completion Time is based on the coolant circulation function and is modified such that the 1 hour is applicable

(continued)

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Residual Heat Removal (RHR) Shutdown Cooling System—Cold Shutdown

BASES

BACKGROUND

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed to maintain the temperature of the reactor coolant at ≤ 200°F. This decay heat removal is in preparation for performing refueling or maintenance operations, or for maintaining the reactor in the Cold Shutdown condition.

The two redundant, manually controlled shutdown cooling subsystems of the RHR System provide decay heat removal. Each loop consists of a motor driven pump, two heat exchangers in series, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via separate feedwater lines or to the reactor via the LPCI injection path. The RHR heat exchangers transfer heat to the Standby Service Water System.

APPLICABLE SAFETY ANALYSES

Decay heat removal by the RHR System in the shutdown cooling mode is not required for mitigation of any event or accident evaluated in the safety analyses. Decay heat removal is, however, an important safety function that must be accomplished or core damage could result. Although the RHR Shutdown Cooling System does not meet a specific criterion of the NRC Policy Statement, it was identified in the NRC Policy Statement as a significant contributor to risk reduction. Therefore, the RHR Shutdown Cooling System is retained as a Technical Specification.

LCO

Two RHR shutdown cooling subsystems are required to be OPERABLE, and, when no recirculation pump is in operation, one RHR shutdown cooling subsystem must be in operation. An OPERABLE RHR shutdown cooling subsystem consists of one OPERABLE RHR pump, two heat exchangers in series, and the associated piping and valves. Each shutdown cooling

(continued)

BASES

ACTIONS

A.1 (continued)

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

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

B.1 and B.2

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

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

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

This Surveillance verifies that one RHR shutdown cooling subsystem or recirculation pump is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Frequency of 12 hours is

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.2

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

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

SR 3.4.12.3 and SR 3.4.12.4

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

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

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.12.4 is to compare the temperatures of the operating recirculation loop and the idle loop.

SR 3.4.12.3 and SR 3.4.12.4 have been modified by a Note that requires the Surveillance to be met only in MODES 1, 2, 3, and 4 with reactor steam dome pressure ≥ 25 psig. In MODE 5, the overall stress on limiting components is lower; therefore, ΔT limits are not required.

during a recirculation pump startup since this is when the stresses occur.

INSERT
SR 3.4.12.5 AND
SR 3.4.12.6

SR 3.4.12.5, SR 3.4.12.6, and SR 3.4.12.7

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

(continued)

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
BASES SECTION 3.4 - REACTOR COOLANT SYSTEMS

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

2. Editorial change made for enhanced clarity or to be consistent with similar statements in other places in the Bases.

3. Typographical/grammatical error corrected.

4. Changes have been made to more closely match the LCO requirements.

5. Changes have been made to reflect those changes made to the Specification. The following requirements have been renumbered, where applicable, to reflect the changes.

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

7. The Specification deals with the flow control valves and there is no reason to reference the jet pumps. Therefore, the reference to jet pumps has been deleted. This concept (not referencing in a "subcomponent" Bases the other "subcomponents" of the associated system) is consistent with other sections of the ITS Bases.

8. The word "may" has been added since a change in the described relationship may be due to other factors. (B)

9. This statement has been deleted since it is misleading; an increase in flow could be indicative of other problems.

10. The bracketed requirement/information has been deleted because it is not applicable to WNP-2. The following requirements have been renumbered, where applicable, to reflect the changes.

11. The proper LCO/SR number has been used.

12. The Note description has been moved to the proper location, consistent with the Writer's Guide conventions. This new location was where the Note, added to Revision 1 by BWOG-2, C.3, was supposed to have been added; however, it was inadvertently added in the wrong location in the typed version of Revision 1.

13. The proper Final Policy Statement criterion has been used. The current wording was developed prior to the issuance of the Final Policy Statement, which uses criterion 4 for the current words of the NUREG.

14. Generic change TSTF-03 has not been adopted. WNP-2 is evaluating this change and will decide whether or not to incorporate this change at a later date.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The ECCS performance is evaluated for the entire spectrum of break sizes for a postulated LOCA. The accidents for which ECCS operation is required are presented in References 5, 6, and 7. The required analyses and assumptions are defined in 10 CFR 50 (Ref. 8), and the results of these analyses are described in Reference 9.

This LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 10), will be met following a LOCA assuming the worst case single active component failure in the ECCS:

a. Maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from zirconium water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;

d. The core is maintained in a coolable geometry; and

e. Adequate long term cooling capability is maintained.

The limiting single failures are discussed in Reference 11. For a large break LOCA, failure of ECCS subsystems in Division 1 (LPCS and LPCI⊘A) or Division 2 (LPCI⊘B and LPCI⊘C) due to failure of its associated diesel generator is, in general, the most severe failure. For a small break LOCA, HPCS System failure is the most severe failure. One ADS valve failure is analyzed as a limiting single failure for events requiring ADS operation. The remaining OPERABLE ECCS subsystems provide the capability to adequately cool the core and prevent excessive fuel damage.

The small break analysis also assumes two ADS valves are inoperable at the time of the accident.

The ECCS satisfy Criterion 3 of the NRC Policy Statement. (Ref. 12)

LCO

Each ECCS injection/spray subsystem and six/eight ADS valves are required to be OPERABLE. The ECCS injection/spray subsystems are defined as the three LPCI subsystems, the LPCS System, and the HPCS System. The low pressure ECCS

(continued)

BASES

ACTIONS

A.1 (continued)

out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (i.e., Completion Times).

B.1 and B.2

If the HPCS System is inoperable, and the RCIC System is verified to be OPERABLE (when RCIC is required to be OPERABLE), the HPCS System must be restored to OPERABLE status within 14 days. In this condition, adequate core cooling is ensured by the OPERABILITY of the redundant and diverse low pressure ECCS injection/spray subsystems in conjunction with the ADS. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Verification of RCIC OPERABILITY ~~within 1 hour~~ is therefore required when HPCS is inoperable and RCIC is required to be OPERABLE. This may be performed by an administrative check, by examining logs or other information to determine if RCIC is not out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the RCIC System. However, if the OPERABILITY of the RCIC System cannot be verified and RCIC is required to be OPERABLE, Condition D must be immediately entered. If a single active component fails concurrent with a design basis LOCA, there is a potential, depending on the specific failure, that the minimum required ECCS equipment will not be available. A 14 day Completion Time is based on the results of a reliability study (Ref. ~~12~~) and has been found to be acceptable through operating experience.

C.1

With two ECCS injection subsystems inoperable or one ECCS injection and one ECCS spray subsystem inoperable, at least one ECCS injection/spray subsystem must be restored to OPERABLE status within ~~72 hours~~. In this condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced in this Condition because a single failure in one of the remaining OPERABLE subsystems concurrent with a design basis

(continued)

BASES

ACTIONS

C.1 (continued)

LOCA may result in the ECCS not being able to perform its intended safety function. Since the ECCS availability is reduced relative to Condition A, a more restrictive Completion Time is imposed. The 72 hours Completion Time is based on a reliability study, as provided in Reference 12.

7 days (4) (13) (1)

D.1 and D.2

If any Required Action and associated Completion Time of Condition A, B, or C are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

The LCO requires eight ADS valves to be OPERABLE to provide the ADS function. Reference 13 contains the results of an analysis that evaluated the effect of one ADS valve being out of service. In this analysis, operation of only seven ADS valves will provide the required depressurization. However, overall reliability of the ADS is reduced because a single failure in the OPERABLE ADS valves could result in a reduction in depressurization capability. Therefore, operation is only allowed for a limited time. The 14 day Completion Time is based on a reliability study (Ref. 12) and has been found to be acceptable through operating experience.

six (4) (1) 15 two (1) (B) (1) showed that assuming a failure of the HPCS System (5) (1) five (1) (14) (1)

F.1 and F.2

required (3)

If any one low pressure ECCS injection/spray subsystem is inoperable in addition to one inoperable ADS valve, adequate core cooling is ensured by the OPERABILITY of HPCS and the remaining low pressure ECCS injection/spray subsystems. However, the overall ECCS reliability is reduced because a single active component failure concurrent with a design

(continued)

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

B 3.5.2 ECCS – Shutdown

BASES

BACKGROUND

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

APPLICABLE SAFETY ANALYSES

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

The ECCS satisfy Criterion 3 of the NRC Policy Statement.

LCO

Two ECCS injection/spray subsystems are required to be OPERABLE. The ECCS injection/spray subsystems are defined as the three LPCI subsystems, the LPCS System, and the HPCS System. The LPCS System and each LPCI subsystem consist of one motor driven pump, piping, and valves to transfer water from the suppression pool to the RPV. The HPCS System consists of one motor driven pump, piping, and valves to transfer water from the suppression pool or condensate storage tank (CST) to the RPV.

One LPCI subsystem (A or B) may be ~~aligned for decay heat removal in MODE 4 or 5 and~~ considered OPERABLE ~~for the ECCS function~~, if ~~it can be~~ manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. Because

The necessary portions of the Standby Service Water and HPCS Service Water Systems, as applicable, are also required to provide appropriate cooling to each required ECCS injection/spray subsystem.

during alignment and operation for decay heat removal

capable of being

INSERT LCO

(continued)

BASES

BACKGROUND (continued)

This Specification ensures that the performance of the primary containment, in the event of a DBA, meets the assumptions used in the safety analyses of References 1 and 2. SR 3.6.1.1.1 leakage rate requirements are in conformance with 10 CFR 50, Appendix J, (Ref. 3), as modified by approved exemptions. Option B (4) (B)

APPLICABLE SAFETY ANALYSES

The safety design basis for the primary containment is that it must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBA that postulates the maximum release of radioactive material within primary containment is a double-ended recirculation suction line break LOCA. (1) In the analysis of this accident, it is assumed that primary containment is OPERABLE such that release of fission products to the environment is controlled by the rate of primary containment leakage.

Analytical methods and assumptions involving the primary containment are presented in References 1 and 2. The safety analyses assume a nonmechanistic fission product release following a DBA, which forms the basis for determination of offsite doses. The fission product release is, in turn, based on an assumed leakage rate from the primary containment. OPERABILITY of the primary containment ensures that the leakage rate assumed in the safety analyses is not exceeded.

The maximum allowable leakage rate for the primary containment (L_a) is 0.5 (3) % by weight of the containment (1) and drywell air per 24 hours at the maximum peak containment pressure (P_a) of 11.5 (3) (38) psig (Ref. 4). design basis LOCA (1) (B)

Primary containment satisfies Criterion 3 of the NRC Policy Statement. (Ref. 5) (1)

LCO

Primary containment OPERABILITY is maintained by limiting leakage to $\leq 1.0\ L_a$, except prior to the first startup after performing a required 10 CFR 50, Appendix J, leakage test. applicable At this time, the combined Type B and C leakage must be limits $< 0.6\ L_a$, and the overall Type A leakage must be $< 0.75\ L_a$. (B) Compliance with this LCO will ensure a primary containment met (4) Primary Containment Leakage Rate Testing Program

(continued)

(4) In addition, the leakage from the drywell to the suppression chamber must be limited to ensure the pressure suppression function is accomplished and the suppression chamber pressure does not exceed design limits.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1

Maintaining the primary containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of 10 CFR 50, Appendix J (Ref. 3), as modified by approved exemptions. Failure to meet air lock leakage testing (SR 3.6.1.2.1 and SR 3.6.1.2.2), secondary containment bypass leakage (SR 3.6.1.3.9), resilient seal primary containment purge valve leakage testing (SR 3.6.1.3.6), or main steam isolation valve leakage (SR 3.6.1.3.10) does not necessarily result in a failure of this SR. The impact of the failure to meet these SRs must be evaluated against the Type A, B, and C acceptance criteria of 10 CFR 50, Appendix J, as modified by approved exemptions (Ref. 3). As left leakage prior to the first startup after performing a required 10 CFR 50, Appendix J, leakage test is required to be $< 0.6\ L_a$ for combined Type B and C leakage, and $< 0.75\ L_a$ for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of $\leq 1.0\ L_a$. At $\leq 1.0\ L_a$ the offsite dose consequences are bounded by the assumptions of the safety analysis. The Frequency is required by 10 CFR 50, Appendix J, as modified by approved exemptions. Thus, SR 3.0.2 (which allows Frequency extensions) does not apply.

INSERT 3.6.1.1.2

SR 3.6.1.1.2

The structural integrity of the primary containment is ensured by the successful completion of the Primary Containment Tendon Surveillance Program and by associated visual inspections of the steel liner and penetrations for evidence of deterioration or breach of integrity. This ensures that the structural integrity of the primary containment will be maintained in accordance with the provisions of the Primary Containment Tendon Surveillance Program. Testing and Frequency are consistent with the recommendations of Regulatory Guide 1.35 (Ref. 5).

REFERENCES

1. FSAR, Section 6.2.1.1.3.5.
2. FSAR, Section 15.6.5.

(continued)

BASES

REFERENCES (continued)

3. 10 CFR 50, Appendix J, Option B. (4)
4. FSAR, Section ~~6.~~ 6.2.6.1 (3)
5. Regulatory Guide 1.35, Revision [1]

(1) Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58FR39132).

(B) (B)

BASES

ACTIONS (continued)

D.1 and D.2

If the inoperable primary containment air lock cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1

Maintaining primary containment air lock OPERABLE requires compliance with the leakage rate test requirements of 10 CFR 50, Appendix J (Ref. 2), as modified by approved exemptions. This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria were established during initial air lock and primary containment OPERABILITY testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall primary containment leakage rate. The Frequency is required by 10 CFR 50, Appendix J, as modified by approved exemptions. Thus, SR 3.0.2 (which allows Frequency extensions) does not apply.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR, requiring the results to be evaluated against the acceptance criteria of SR 3.6.1.1.1. This ensures that air lock leakage is properly accounted for in determining the overall primary containment leakage.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.4 (continued)

plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the [18] month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(4)

REFERENCES

1. FSAR, Section ~~3.8~~. .2.1.1.4 (3) (1)
2. 10 CFR 50, Appendix J, option B. (5) 2. FSAR, Section 3.8.2.7.5. (B)
3. ~~FSAR, Table 6.2-13~~ FSAR, Section 6.2.6.1 (3)

(1)
4. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
6. FSAR, Section 3.8.2.7.3.

BASES

APPLICABLE SAFETY ANALYSES (continued)

[The purge valves may be unable to close in the environment following a LOCA. Therefore, each of the purge valves is required to remain sealed closed during MODES 1, 2, and 3. In this case, the single failure criterion remains applicable to the primary containment purge valve due to failure in the control circuit associated with each valve. Again, the primary containment purge valve design precludes a single failure from compromising the primary containment boundary as long as the system is operated in accordance with this LCO.]

PCIVs satisfy Criterion 3 of the NRC Policy Statement. (Ref. 3)

LCO

PCIVs form a part of the primary containment boundary. The PCIV safety function is related to minimizing the loss of reactor coolant inventory and establishing the primary containment boundary during a DBA.

The power operated, automatic isolation valves are required to have isolation times within limits and actuate on an automatic isolation signal. Primary containment purge valves that are not qualified to close under accident conditions must be sealed closed [or blocked to prevent full opening] to be OPERABLE. The valves covered by this LCO are listed with their associated stroke times in the FSAR (Ref. 3), Reference 4.

The normally closed PCIVs are considered OPERABLE when manual valves are closed or open in accordance with appropriate administrative controls, automatic valves are de-activated and secured in their closed position, blind flanges are in place, and closed systems are intact. These passive isolation valves and devices are those listed in Reference 3. Purge valves with resilient seals, secondary bypass valves, MSIVs, and hydrostatically tested valves must meet additional leakage rate requirements. Other PCIV leakage rates are addressed by LCO 3.6.1.1, "Primary Containment," as Type B or C testing.

This LCO provides assurance that the PCIVs will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the primary containment boundary during accidents.

MSIV and hydrostatically tested valve leakage are exempt from Type C testing limits and must meet specific leakage rate requirements, and secondary containment bypass valves must

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.9 (continued)

the two isolation valves) unless the penetration is isolated by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. In this case, the leakage rate of the isolated bypass leakage path is assumed to be the actual pathway leakage through the isolation device. If both isolation valves in the penetration are closed, the actual leakage rate is the lesser leakage rate of the two valves. This method of quantifying maximum pathway leakage is only to be used for this SR (i.e., Appendix J maximum pathway leakage limits are to be quantified in accordance with Appendix J). The Frequency is required by 10 CFR 50, Appendix J, as modified by approved exemptions (and therefore, the Frequency extensions of SR 3.0.2 may not be applied), since the testing is an Appendix J, Type C test. This SR simply imposes additional acceptance criteria.

the Primary Containment Leakage Rate Testing Program

Note 1 is added to this SR which states that these valves are only required to meet this leakage limit in MODES 1, 2, and 3. In the other conditions, the Reactor Coolant System is not pressurized and specific primary containment leakage limits are not required.

[Bypass leakage is considered part of L_a. [Reviewer's Note: Unless specifically exempted].]

SR 3.6.1.3.10

The analyses in References 2 and 3 are based on leakage that is less than the specified leakage rate. Leakage through each MSIV must be ≤ 11.5 scfh when tested at P_a (25 psig). The MSIV leakage rate must be verified to be in accordance with the leakage test requirements of Reference 4, as modified by approved exemptions. Note 1 is added to this SR which states that these valves are only required to meet this leakage limit in MODES 1, 2, and 3. In the other conditions, the Reactor Coolant System is not pressurized and specific primary containment leakage limits are not required. This ensures that MSIV leakage is properly accounted for in determining the overall primary containment leakage rate. The Frequency is required by 10 CFR 50, Appendix J (Ref. 4), as modified by approved

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.10 (continued)

exemptions; thus, SR 3.0.2 (which allows Frequency extensions) does not apply.

The acceptance criteria for the combined leakage of all hydrostatically tested lines is ≤1.0 gpm times the total number of hydrostatically tested PCIVs when tested at 1.1 Pa (41.8 psig).

SR 3.6.1.3.11

Surveillance of hydrostatically tested lines provides assurance that the calculation assumptions of References 2 and 3 are met. The combined leakage rates must be demonstrated to be in accordance with the leakage test frequency of Reference 4, as modified by approved exemptions; thus SR 3.0.2 (which allows Frequency extensions) does not apply.

required by the Primary Containment Leakage Rate Testing Program

[This SR is modified by a Note that states that these valves are only required to meet the combined leakage rate in MODES 1, 2, and 3 since this is when the Reactor Coolant System is pressurized and primary containment is required. In some instances, the valves are required to be capable of automatically closing during MODES other than MODES 1, 2, and 3. However, specific leakage limits are not applicable in these other MODES or conditions.]

SR 3.6.1.3.12

Reviewer's Note: This SR is only required for those plants with purge valves with resilient seals allowed to be open during [MODE 1, 2, or 3] and having blocking devices on the valves that are not permanently installed.

Verifying that each [ ] inch primary containment purge valve is blocked to restrict opening to ≤ [50%] is required to ensure that the valves can close under DBA conditions within the time limits assumed in the analyses of References 2 and 3.

The SR is modified by a Note stating that this SR is only required to be met in MODES 1, 2, and 3. If a LOCA inside primary containment occurs in these MODES, the purge valves must close to maintain containment leakage within the values assumed in the accident analysis. At other times when purge valves are required to be capable of closing (e.g., during movement of irradiated fuel assemblies), pressurization

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.12 (continued)

concerns are not present, thus the purge valves can be fully open. The [18] month Frequency is appropriate because the blocking devices are typically removed only during a refueling outage.

REFERENCES

1. FSAR, Chapter [15].
2. FSAR, Section [6.2].
3. FSAR, ~~Table 6.2-44~~.
4. ~~10 CFR 50, Appendix J.~~ Licensee Controlled Specifications Manual

Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

Changes per TSTF-30 not adopted

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.0 Residual Heat Removal (RHR) containment Spray system

BASES

BACKGROUND

The primary containment is designed with a suppression pool so that, in the event of a loss of coolant accident (LOCA), steam released from the primary system is channeled through the suppression pool water and condensed without producing significant pressurization of the primary containment. The primary containment is designed so that with the pool initially at the minimum water volume and the worst single failure of the primary containment heat removal systems, suppression pool energy absorption combined with subsequent operator controlled pool cooling will prevent the primary containment pressure from exceeding its design value. However, the primary containment must also withstand a postulated bypass leakage pathway that allows the passage of steam from the drywell directly into the primary containment airspace, bypassing the suppression pool. The primary containment also must withstand a low energy steam release into the primary containment airspace. The RHR containment Spray System is designed to mitigate the effects of bypass leakage and low energy line breaks.

There are two redundant, 100% capacity RHR containment spray subsystems. Each subsystem consists of a suction line from the suppression pool, an RHR pump, a heat exchanger, and three spray spargers inside the primary containment (outside of the drywell) above the refueling floor. Dispersion of the spray water is accomplished by 150 nozzles in each subsystem.

The RHR containment spray mode will be automatically initiated, if required, following a LOCA, or it may be manually initiated according to emergency procedures.

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses that predict the primary containment pressure response for a LOCA with the maximum allowable bypass leakage area.

The equivalent flow path area for bypass leakage has been specified to be 0.9 ft^2. The analysis demonstrates that

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

with containment spray operation the primary containment pressure remains within design limits.

The RHR Containment Spray System satisfies Criterion 3 of the NRC Policy Statement.

LCO

In the event of a Design Basis Accident (DBA), a minimum of one RHR containment spray subsystem is required to mitigate potential bypass leakage paths and maintain the primary containment peak pressure below design limits. To ensure that these requirements are met, two RHR containment spray subsystems must be OPERABLE. Therefore, in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active failure. An RHR containment spray subsystem is OPERABLE when the pump, the heat exchanger, and associated piping, valves, instrumentation, and controls are OPERABLE.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause pressurization of primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining RHR containment spray subsystems OPERABLE is not required in MODE 4 or 5.

ACTIONS

A.1

With one RHR containment spray subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE RHR containment spray subsystem is adequate to perform the primary containment cooling function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced primary containment cooling capability. The 7 day Completion Time was chosen in light of the redundant RHR containment capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

(continued)

INSERT BWR/4 3.6.1.7 (continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The suppression chamber-to-drywell vacuum breakers satisfy Criterion 3 of the NRC Policy Statement. (Ref. 2)

LCO

Only [8] of the [12] vacuum breakers must be OPERABLE for opening. All suppression chamber-to-drywell vacuum breakers, however, are required to be closed (except during testing or when the vacuum breakers are performing their intended design function). The vacuum breaker OPERABILITY requirement provides assurance that the drywell-to-suppression chamber negative differential pressure remains below the design value. The requirement that the vacuum breakers be closed ensures that there is no excessive bypass leakage should a LOCA occur.

A vacuum breaker is OPERABLE for opening and closed when both disks in the vacuum breaker are OPERABLE for opening and closed.

APPLICABILITY

In MODES 1, 2, and 3, the Suppression Pool Spray System is required to be OPERABLE to mitigate the effects of a DBA. Excessive negative pressure inside the drywell could also occur due to inadvertent actuation of this system. The vacuum breakers, therefore, are required to be OPERABLE in MODES 1, 2, and 3, when the Suppression Pool Spray System is required to be OPERABLE, to mitigate the effects of inadvertent actuation of the Suppression Pool Spray System.

Also, in MODES 1, 2, and 3, a DBA could result in excessive negative differential pressure across the drywell wall, caused by the rapid depressurization of the drywell. The event that results in the limiting rapid depressurization of the drywell is the primary system rupture that purges the drywell of air and fills the drywell free airspace with steam. Subsequent condensation of the steam would result in depressurization of the drywell. The limiting pressure and temperature of the primary system prior to a DBA occur in MODES 1, 2, and 3. the Drywell Spray System

In MODES 4 and 5, the probability and consequences of these events are reduced by the pressure and temperature limitations in these MODES; therefore, maintaining suppression chamber-to-drywell vacuum breakers OPERABLE is not required in MODE 4 or 5.

(continued)

Insert Page B 3.6-47c

16 * Insert BWR/4 B 3.6.3.2

Primary Containment Atmosphere Mixing System | B

3 [Drywell Cooling System Fans]

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.2 [Drywell Cooling System Fans] ← 3

Primary Containment Atmosphere Mixing System | B

BASES

BACKGROUND

The [Drywell Cooling System fans] ensure a uniformly mixed post accident primary containment atmosphere, thereby minimizing the potential for local hydrogen burns due to a pocket of hydrogen above the flammable concentration. | B

Primary Containment Atmosphere Mixing System 3

The [Drywell Cooling System fans] are an Engineered Safety Feature and are designed to withstand a loss of coolant accident (LOCA) in post accident environments without loss of function. The system has two independent subsystems consisting of fans, fan coil units, motors, controls, and ducting. Each subsystem is sized to circulate [50%] scfm. 5000 3

is 1

1

1

head area return

The [Drywell Cooling System fans] employ both forced circulation and natural circulation to ensure the proper mixing or hydrogen in primary containment. The recirculation fans provide the forced circulation to mix hydrogen while the fan coils provide the natural circulation by increasing the density through the cooling of the hot gases at the top of the drywell causing the cooled gases to gravitate to the bottom of the drywell. The two subsystems are initiated manually since flammability limits would not be reached until several days after a LOCA. Each subsystem is powered from a separate emergency power supply. Since each subsystem can provide 100% of the mixing requirements, the system will provide its design function with a worst case single active failure. 5 1 | B

Primary Containment Atmosphere Mixing System 3

and oxygen

1 automatically

upon a reactor scram signal. However, for the purposes of this LCO, the subsystems are only required to be initiated

The [Drywell Cooling System fans] use the Drywell Cooling System recirculating fans to mix the drywell atmosphere. The fan coil units and recirculation fans are automatically disengaged during a LOCA but may be restored to service manually by the operator. In the event of a loss of offsite power, all fan coil units, recirculating fans, and primary containment water chillers are transferred to the emergency diesels. The fan coil units and recirculating fans are started automatically from diesel power upon loss of offsite power. 1

(continued)

* This BWR/4 Bases was inserted to match the BWR/4 Specification inserted in the LCO Section

Insert Page B 3.6-86a

Insert BWR/4 B 3.6.3.2 (continued)

16

Primary Containment Atmosphere Mixing System

3

[Drywell Cooling System Fans]

B 3.6.3.2

B

BASES (continued)

APPLICABLE SAFETY ANALYSES

The [Drywell Cooling System fans] provide the capability for reducing the local hydrogen concentration to approximately the bulk average concentration following a Design Basis Accident (DBA). The limiting DBA relative to hydrogen generation is a LOCA.

1 and oxygen

5 1 and oxygen

1 Insert ASA-1

Hydrogen may accumulate in primary containment following a LOCA as a result of:

a. A metal steam reaction between the zirconium fuel rod cladding and the reactor coolant; or

1

b. Radiolytic decomposition of water in the Reactor Coolant System; or

1 and oxygen

1 Insert ASA-2

To evaluate the potential for hydrogen accumulation in primary containment following a LOCA, the hydrogen generation as a function of time following the initiation of the accident is calculated. Conservative assumptions recommended by Reference 1 are used to maximize the amount of hydrogen calculated.

1 oxygen

1 Insert ASA-3

The Reference 2 calculations show that hydrogen assumed to be released to the drywell within 2 minutes following a DBA LOCA raises drywell hydrogen concentration to over 2.5 volume percent (v/o). Natural circulation phenomena result in a gradient concentration difference of less then 0.5 v/o in the drywell and less than 0.1 v/o in the suppression chamber. Even though this gradient is acceptably small and no credit for mechanical mixing was assumed in the analysis, two [Drywell Cooling System fans] are [required] to be OPERABLE (typically four to six fans are required to keep the drywell cool during operation in MODE 1 or 2) by this LCO.

B

Primary Containment Atmosphere Mixing System

3

satisfies

The [Drywell Cooling System fans] satisfy Criterion 3 of the NRC Policy Statement.

3

LCO

3 head area return

Two [Drywell Cooling System fans] must be OPERABLE to ensure operation of at least one fan in the event of a worst case single active failure. Each of these fans must be powered from an independent safety related bus.

1

(continued)

Insert Page B 3.6-86

Insert BWR/4 B 3.6.3.2 (16)

(continued)

(1) INSERT ASA-1

Oxygen may accumulate in the primary containment following a LOCA as a result of radiolytic decomposition of water in the Reactor Coolant System.

(1) INSERT ASA-2

c. A reaction between the reactor coolant and the zinc rich paints used in the primary containment. However, since WNP-2 is an oxygen control plant, this form of hydrogen generation is not assumed (minimizing hydrogen production is conservative in calculating peak oxygen concentration).

(1) INSERT ASA-3

The calculation confirms that one head area return fan started in accordance with plant procedures will ensure adequate mixing of hydrogen and oxygen within the primary containment atmosphere (Refs. 2 and 3). (15)

Insert BWR/4 B 3.6.3.2 (continued)

[Drywell Cooling System Fans]
B 3.6.3.2

BASES

LCO (continued)

Operation with at least one fan provides the capability of controlling the bulk hydrogen concentration in primary containment without exceeding the flammability limit.

APPLICABILITY

In MODES 1 and 2, the two [Drywell Cooling System fans] ensure the capability to prevent localized hydrogen concentrations above the flammability limit of 4.0 v/o in drywell, assuming a worst case single active failure.

In MODE 3, both the hydrogen production rate and the total hydrogen produced after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in this MODE, the probability of an accident requiring the [Drywell Cooling System fans] is low. Therefore, the [Drywell Cooling System fans] are not required in MODE 3.

In MODES 4 and 5, the probability and consequences of a LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, the [Drywell Cooling System fans] are not required in these MODES.

ACTIONS

A.1

With one [required] [Drywell Cooling System fan] inoperable, the inoperable fan must be restored to OPERABLE status within 30 days. In this condition, the remaining OPERABLE fan is adequate to perform the hydrogen mixing function. However, the overall reliability is reduced because a single failure in the OPERABLE fan could result in reduced hydrogen mixing capability. The 30 day Completion Time is based on the availability of the second fan, the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit, the amount of time available after the event for operator action to prevent exceeding this limit, and the availability of the Primary Containment Hydrogen Recombiner System and the Containment Atmosphere Dilution System.

Required Action A.1 has been modified by a Note indicating that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one [Drywell Cooling System fan] is inoperable. This allowance is provided

(continued)

Insert page B 3.6-86d

Insert BWR/4 B 3.6.3.2 (continued)

Primary Containment Atmosphere Mixing System

[Drywell Cooling System Fans]

BASES

ACTIONS

A.1 (continued)

because of the low probability of the occurrence of a LOCA that would generate hydrogen and oxygen in amounts capable of exceeding the flammability limit, the low probability of the failure of the OPERABLE fan, and the amount of time available after a postulated LOCA for operator action to prevent exceeding the flammability limit.

B.1 and B.2

[Reviewer's Note: This Condition is only allowed for units with an alternate hydrogen control system acceptable to the technical staff.]

With two [Drywell Cooling System fans] inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control capabilities are provided by the [Primary Containment Inerting System or one subsystem of the Containment Atmosphere Dilution System]. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. [Reviewer's Note: The following is to be used if a non-Technical Specification alternate hydrogen control function is used to justify this Condition: In addition, the alternate hydrogen control system capability must be verified once per 12 hours thereafter to ensure its continued availability.] [Both] the [initial] verification [and all subsequent verifications] may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen control system. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control system. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two [Drywell Cooling System fans] inoperable for up to 7 days. Seven days is a reasonable time to allow two [Drywell Cooling System fans] to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit.

(continued)

Insert Page B 3.6-86e

(16) Insert Bar/4 B 3.6.3.2. (continued)

BASES

ACTIONS (continued)

C.1

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.2.1

Operating each [required] [Drywell Cooling System fan] (head area return) (3) for ≥ 15 minutes ensures that each subsystem is OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, (OR) (4) excessive vibration (24) can be detected for corrective action. The 92 day Frequency is consistent with the Inservice Testing Program Frequencies, operating experience, the known reliability of the fan motors and controls, and the two redundant fans available.

(4)

SR 3.6.3.2.2

Verifying that each [required] [Drywell Cooling System fan] flow rate is ≥ [500] scfm ensures that each fan is capable of maintaining localized hydrogen concentrations below the flammability limit. The [18] month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. Regulatory Guide 1.7, Revision [1], September 1976. (1)
2. FSAR, Section [6.2.5] .2.1. (3)
3. GNP-2 Technical Memo TM-2065, "Requirements for Containment Mixing Fans," Revision 0, July 15, 1994. (1)

Insert Page B 3.6-86f

13. These changes have been made for consistency with similar phrases in other parts of the Bases and/or to be consistent with the Specification.

14. This change was approved to be made in NUREG-1434, Revision 1 per change package BWR-15, C.4, but apparently was not made. This change was made to the BWR/4 ITS, NUREG-1433, Revision 1.

15. This Bases section has been deleted because the associated Specification has been deleted.

16. Four new Bases have been added, proposed Bases 3.6.1.6, Bases 3.6.1.7, Bases 3.6.3.2, and Bases 3.6.3.3. These Bases are from the BWR/4 ITS (NUREG-1433), since the WNP-2 design is similar to the BWR/4 design with regard to the vacuum breakers, Primary Containment Atmosphere Mixing System, and oxygen concentration requirements. Therefore, the BWR/4 Bases are used and any deviations from the BWR/4 ITS are discussed. 1 B

17. The discussions of the five different analysis cases have been deleted. The appropriate analysis is described in the FSAR (Reference 1) and discussion in the Bases is not needed for understanding this Specification.

18. Inadvertent actuation of the Suppression Pool Spray System is not the main concern for depressurizing the drywell; a LOCA inside the drywell is the main concern. Therefore, this section has been reworded to place the emphasis on the proper reason. In addition, inadvertent actuation of the Drywell Spray System is the secondary concern, not the Suppression Pool Spray System.

19. The statement has been modified since it is incorrect; the pressure could be positive or negative depending upon the situation. Also, the design basis only assumes the pressure is within the limits, not positive. Therefore, the breakers are required to remain closed only "until" the suppression pool is at a positive pressure relative to the drywell. At this time, they may be open to perform their design function (i.e., relieve pressure).

20. The discussions of the four different concerns that lead to the development of the suppression pool average temperature limits have been deleted. The appropriate analysis is described in the FSAR (References 1 and 2) and discussion in the Bases is not needed for understanding this Specification.

21. The specific requirement for the subsystems to be powered from two safety related independent power supplies has been deleted since the design of the system already reflects this. This statement is not used in other LCO Bases where the system is designed with independent power supplies (e.g., Bases 3.6.3.1, "Primary Containment Hydrogen Recombiners").

22. The IST Program at WNP-2 is not required to provide information for trend purposes. Therefore, these words have been deleted.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

sequence interval associated with sequencing of this largest load. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.9.a corresponds to the maximum frequency excursion, while SR 3.8.1.9.b and SR 3.8.1.9.c are steady state voltage and frequency values to which the system must recover following load rejection. The [18] month Frequency is consistent with the recommendation of Regulatory Guide 1.108 (Ref. 9).

This SR has been modified by two Notes. The reason for Note 1 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, Note 2 requires that, if synchronized to offsite power, testing must be performed using a power factor ≤ [0.9]. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could experience.

INSERT SR 3.8.1.9

Reviewer's Note: The above MODE restrictions may be deleted if it can be demonstrated to the staff, on a plant specific basis, that performing the SR with the reactor in any of the restricted MODES can satisfy the following criteria, as applicable:

a. Performance of the SR will not render any safety system or component inoperable;

b. Performance of the SR will not cause perturbations to any of the electrical distribution systems that could result in a challenge to steady state operation or to plant safety systems; and

c. Performance of the SR, or failure of the SR, will not cause, or result in, an AOO with attendant challenge to plant safety systems.

(continued)

INSERT SR 3.8.1.9

(4) To meet these power factor limits, the DGs must be loaded to the following reactive values when the SR is performed; 580 kVAR for DG-1, 760 kVAR for DG-2, and 1015 kVAR for DG-3. However, if the offsite electrical power distribution system voltage is high, increased excitation will be necessary for the DG to match system voltage when synchronizing to the associated ESF bus. Once tied to the ESF bus, it may not be possible to increase DG excitation sufficiently to (8) meet the required reactive load value that ensures the power factor limit is met, without exceeding the DG excitation system ratings. Therefore, to ensure the DG is not placed in an unsafe condition during this test, the power factor limit does not have to be met if grid voltage does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the power factor should be maintained as close to the limit as practicable. (5)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.10

This Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide DG damage protection. While the DG is not expected to experience this transient during an event, and continues to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing must be performed within the power factor limit. ~~≤ 0.9~~. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.

The ~~18~~ 24 month Frequency is consistent with the recommendation of Regulatory Guide 1.108 (Ref. 9) and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by a Note. The reason for the Note is that during operation with the reactor critical, performance of this SR could cause perturbation to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

Reviewer's Note: The above MODE restrictions may be deleted if it can be demonstrated to the staff, on a plant specific basis, that performing the SR with the reactor in any of the restricted MODES can satisfy the following criteria, as applicable:

a. Performance of the SR will not render any safety system or component inoperable;

(continued)

(4)

INSERT SR 3.8.1.10a

To meet these power factor limits, the DGs must be loaded to the following reactive values when the SR is performed: 2165 kVAR for DG-1, 2085 kVAR for DG-2, and 1150 kVAR for DG-3. (B)

(8)

INSERT SR 3.8.1.10b (B)

Note 2 is provided in recognition that if the offsite electrical power distribution system voltage is high, increased excitation will be necessary for the DG to match system voltage when synchronizing to the associated ESF bus. Once tied to the ESF bus, it may not be possible to increase DG excitation sufficiently to meet the required reactive load value that ensures the power factor limit is met, without exceeding the DG excitation system ratings. Therefore, to ensure the DG is not placed in an unsafe condition during this test, the power factor limit does not have to be met if grid voltage does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the power factor should be maintained as close to the limit as practicable. (B)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.14

Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(3), requires demonstration once per 18 months that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours—22 hours of which is at a load equivalent to the continuous rating of the DG and 2 hours of which is at a load equivalent to 110% of the continuous duty rating of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelube and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed using a power factor limit. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could experience.

<Insert SR 3.8.1.14a>

The 24 month Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(3), takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by three Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. 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. Similarly, momentary power factor transients above the limit do not invalidate the test. The reason for Note 2 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that would challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

<Insert SR 3.8.1.14b>

(continued)

(4)

INSERT SR 3.8.1.14a

To meet these power factor limits, the DGs must be loaded to the following reactive values when the SR is performed: 2165 kVAR for DG-1, 2085 kVAR for DG-2, and 1150 kVAR for DG-3. (5)

INSERT SR 3.8.1.14b (6)

Note 3 is provided in recognition that if the offsite electrical power distribution system voltage is high, increased excitation will be necessary for the DG to match system voltage when synchronizing to the associated ESF bus. Once tied to the ESF bus, it may not be possible to increase DG excitation sufficiently to meet the required reactive load value that ensures the power factor limit is met, without exceeding the DG excitation system ratings. Therefore, to ensure the DG is not placed in an unsafe condition during this test, the power factor limit does not have to be met if grid voltage does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the power factor should be maintained as close to the limit as practicable. (7)

BASES (continued) — TSTF-02

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.6

Draining of the fuel oil stored in the supply tanks, removal of accumulated sediment, and tank cleaning are required at 10 year intervals by Regulatory Guide 1.137 (Ref. 2), paragraph 2.f. This SR is typically performed in conjunction with the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 7), examinations of the tanks. To preclude the introduction of surfactants in the fuel oil system, the cleaning should be accomplished using sodium hypochlorite solutions, or their equivalent, rather than soap or detergents. This SR is for preventive maintenance. The presence of sediment does not necessarily represent a failure of this SR provided that accumulated sediment is removed during performance of the Surveillance.

REFERENCES

1. FSAR, Section {9.5.4}.
2. Regulatory Guide 1.137, Revision 1, October 1979.
3. ANSI N195, Appendix B, 1976.
4. FSAR, Chapter {6}.
5. FSAR, Chapter {15}.
6. ASTM Standards: D4057-{ }; D975-{ }; D4176-{ }; D975-1 ( ); D1552-{ }; D2622-{ }; D2276-{ }.
7. ASME, Boiler and Pressure Vessel Code, Section XI, 1986-83 TSTF-02
6. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.3

Visual inspection of the battery cells, cell plates, and battery racks provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

The 12 month Frequency of this SR is consistent with IEEE-450 (Ref. 8), which recommends detailed visual inspection of cell condition and inspection of cell to cell and terminal connection resistance on a yearly basis.

INSERT SR 3.8.4.3

TSTF-38

SR 3.8.4.4 and SR 3.8.4.5

Visual inspection and resistance measurements of inter-cell, inter-rack, inter-tier and terminal connections provides an indication of physical damage or abnormal deterioration that could indicate degraded battery condition. The anti-corrosion material is used to ensure good electrical connections and to reduce terminal deterioration. The visual inspection for corrosion is not intended to require removal of and inspection under each terminal connection.

The removal of visible corrosion is a preventive maintenance SR. The presence of visible corrosion does not necessarily represent a failure of this SR, provided visible corrosion is removed during performance of this Surveillance.

For inter-cell connectors, the limits are ≤ 24.4 E-6 ohms for the Division I and 2 batteries and ≤ 169 E-6 ohms for the Division 3 battery. For inter-tier and inter-rack connectors,

Reviewer's Note: The requirement to verify that terminal connections are clean and tight applies only to nickel cadmium batteries as per IEEE Standard P1106, "IEEE Recommended Practice for Installation, Maintenance, Testing and Replacement of Vented Nickel - Cadmium Batteries for Stationary Applications." This requirement may be removed for lead acid batteries.

The connection resistance limits ~~for this SR must be no more than~~ are ≤ 20% above the resistance as measured during installation, or not above the ceiling value established by the manufacturer.

The 12 month Frequency of these SRs is consistent with IEEE-450 (Ref. 8), which recommends detailed visual inspection of cell condition and inspection of cell to cell and terminal connection resistance on a yearly basis.

(continued)

TSTF-38

INSERT SR 3.8.4.3

The presence of physical damage or deterioration does not necessarily represent a failure of this SR, provided an evaluation determines that the physical damage or deterioration does not affect the OPERABILITY of the battery (its ability to perform its design function).

B

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.8 (continued)

acceptable for satisfying SR 3.8.4.8; however, only the modified performance discharge test may be used to satisfy SR 3.8.4.8 while satisfying the requirements of SR 3.8.4.7 at the same time.

for 125 V batteries

The acceptance criteria for this Surveillance is consistent with IEEE-450 (Ref. 8) and IEEE-485 (Ref. 12). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the ~~battery rate of deterioration is increasing~~, even if there is ample capacity to meet the load requirements.

INSERT 3.8.4.8-B

for the 125 V battery and 83.4% for the 250 V battery

battery is getting old and capacity will decrease more rapidly

The Surveillance Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 12 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's rating. Degradation is indicated, according to IEEE-450 (Ref. 8), when the battery capacity drops by more than 10% relative to its capacity on the previous performance tests or when it is ≥ 10% below the manufacturer's rating. All these frequencies are consistent with the recommendations in IEEE-450 (Ref. 8).

average

90% of

The 24 month and 60 month

INSERT 3.8.4.8-C

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. Regulatory Guide 1.6, March 10, 1971. (Revision 0,)
3. IEEE Standard 308, 1978.
4. FSAR, Section 8.3.2.
5. WNP-2 Calculation 2.05.01, Rev. 8, February 1990.
6. WNP-2 Calculation E/I 02-35-02, Rev. 1, April 1989.

The 24 month frequency is derived from the recommendations in IEEE-450 (Ref. 11).

(continued)

BASES

BACKGROUND (continued)

the core whenever any control rod is withdrawn, or to prevent control rod withdrawal whenever fuel loaded refueling equipment is over the core (Ref. 2).

(4) The hoist switches open at a load lighter than the weight of a single fuel assembly in water.

Insert Background-2 (move to prev. page)

APPLICABLE SAFETY ANALYSES

The refueling interlocks are explicitly assumed in the FSAR analysis of the control rod removal error during refueling (Ref. 3). This analysis evaluates the consequences of control rod withdrawal during refueling. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment.

Criticality and, therefore, subsequent prompt reactivity excursions are prevented during the insertion of fuel, provided all control rods are fully inserted during the fuel insertion. The refueling interlocks accomplish this by preventing loading fuel into the core with any control rod withdrawn, or by preventing withdrawal of a rod from the core during fuel loading.

The refueling platform location switches activate at a point outside of the reactor core, such that, considering switch hysteresis and maximum platform momentum toward the core at the time of power loss, with a fuel assembly loaded and a control rod withdrawn, the fuel is not over the core. (1)

Refueling equipment interlocks satisfy Criterion 3 of the NRC Policy Statement. (Ref. 4) (1)

LCO

To prevent criticality during refueling, the refueling interlocks ensure that fuel assemblies are not loaded (4) into the core with any control rod withdrawn. associated with the refuel position (2) (B)

To prevent these conditions from developing, the all-rods-in, the refueling platform position, and the refueling platform main hoist fuel loaded inputs are required to be OPERABLE. These inputs are combined in logic circuits that provide refueling equipment or control rod

(continued)

fuel grapple fuel-loaded, the refueling platform frame-mounted hoist fuel-loaded, and the refueling platform trolley-mounted hoist fuel-loaded.

BASES

LCO (continued)

blocks to prevent operations that could result in criticality during refueling operations.

APPLICABILITY

In MODE 5, a prompt reactivity excursion could cause fuel damage and subsequent release of radioactive material to the environment. The refueling equipment interlocks protect against prompt reactivity excursions during MODE 5. The interlocks are only required to be OPERABLE during in-vessel fuel movement with refueling equipment associated with the interlocks.

In MODES 1, 2, 3, and 4, the reactor pressure vessel head is on, and no fuel loading activities are possible. Therefore, the refueling interlocks are not required to be OPERABLE in these MODES.

When the reactor mode switch is in the refuel position. The interlocks are not required when the reactor mode switch is in the shutdown position since a control rod block (LCO 3.3.2.1, "Control Rod Block Instrumentation") ensures control rod withdrawals cannot occur simultaneously with in-vessel fuel movements. (2)

(B)

ACTIONS

A.1

With one or more of the required refueling equipment interlocks inoperable, the unit must be placed in a condition in which the LCO does not apply. In-vessel fuel movement with the affected refueling equipment must be immediately suspended. This action ensures that operations are not performed with equipment that would potentially not be blocked from unacceptable operations (e.g., loading fuel into a cell with a control rod withdrawn). Suspension of in-vessel fuel movement shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

Performance of a CHANNEL FUNCTIONAL TEST demonstrates each required refueling equipment interlock will function properly when a simulated or actual signal indicative of a required condition is injected into the logic. The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping, or total channel steps so that the entire channel is tested.

(continued)

B 3.9 REFUELING OPERATIONS

B 3.9.6 Reactor Pressure Vessel (RPV) Water Level – Irradiated Fuel (3)

BASES

BACKGROUND

The movement of irradiated fuel assemblies or handling of (3) control rods within the RPV requires a minimum water level of 22 ft 6 inches above the top of the RPV flange. During refueling, this maintains a sufficient water level in the upper containment pool. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Refs. 1 and 2). Sufficient iodine activity would be retained to limit offsite doses from the accident to < 25% of 10 CFR 100 limits, as provided by the guidance of Reference 3.

(1) reactor vessel cavity and spent fuel storage

(3)

APPLICABLE SAFETY ANALYSES

During movement of irradiated fuel assemblies (3) or handling of control rods the water level in the RPV is an initial condition design parameter in the analysis of a fuel handling accident in containment postulated by Regulatory Guide 1.25 (Ref. 1). A minimum water level of 23 ft allows (1) a decontamination factor of 100 (Ref. 4) to be used in the accident analysis for iodine. This relates to the assumption that 99% of the total iodine released from the pellet to cladding gap of all the dropped fuel assembly rods is retained by the refueling cavity water. The fuel pellet to cladding gap is assumed to contain 10% of the total fuel rod iodine inventory (Ref. 1).

(4) (Regulatory Position C.1.c of Ref. 1)

(1) Regulatory Position C.1.g of

Analysis of the fuel handling accident inside containment is described in Reference 2. With a minimum water level of (22) 23 ft, and a minimum decay time of 24 hours prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water, and that offsite doses are maintained within allowable limits (Ref. 4).

(1) a decontamination factor of 100 is still expected at a water level as low as 22 ft)

(1) While the worst case assumptions include the dropping of the irradiated fuel assembly being handled onto the reactor core, the possibility exists of the dropped assembly striking the RPV flange and releasing fission products. Therefore, the minimum depth for water coverage to ensure

(continued)

B 3.9 REFUELING OPERATIONS

B 3.9.8 Residual Heat Removal (RHR) – High Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 5 is to remove decay heat and sensible heat from the reactor coolant, as required by GDC 34. Each of the two shutdown cooling loops of the RHR System can provide the required decay heat removal. Each loop consists of one motor driven pump, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via separate feedwater lines or to the upper containment pool via a common single flow distribution sparger or to the reactor via the low pressure coolant injection path. The RHR heat exchangers transfer heat to the Standby Service Water System. The RHR shutdown cooling mode is manually controlled.

In addition to the RHR subsystems, the volume of water above the reactor pressure vessel (RPV) flange provides a heat sink for decay heat removal.

APPLICABLE SAFETY ANALYSES

With the unit in MODE 5, the RHR System is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR System is required for removing decay heat to maintain the temperature of the reactor coolant.

Although the RHR System does not meet a specific criterion of the NRC Policy Statement, it was identified in the NRC Policy Statement as an important contributor to risk reduction. Therefore, the RHR System is retained as a Specification.

LCO

Only one RHR shutdown cooling subsystem is required to be OPERABLE in MODE 5 with irradiated fuel in the RPV and the water level ≥ 22 ft 8 inches above the RPV flange. Only one subsystem is required because the volume of water above the RPV flange provides backup decay heat removal capability.

(continued)

B 3.9 REFUELING OPERATIONS

B 3.9.9 Residual Heat Removal (RHR) – Low Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 5 is to remove decay heat and sensible heat from the reactor coolant, as required by GDC 34. Each of the two shutdown cooling loops of the RHR System can provide the required decay heat removal. Each loop consists of one motor driven pump, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via separate feedwater lines, to the upper containment pool via a common single flow distribution sparger, or to the reactor via the low pressure coolant injection path. The RHR heat exchangers transfer heat to the Standby Service Water System. The RHR shutdown cooling mode is manually controlled.

APPLICABLE SAFETY ANALYSES

With the unit in MODE 5, the RHR System is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR System is required for removing decay heat to maintain the temperature of the reactor coolant.

Although the RHR System does not meet a specific criterion of the NRC Policy Statement, it was identified in the NRC Policy Statement as an important contributor to risk reduction. Therefore, the RHR System is retained as a Specification.

LCO

In MODE 5 with irradiated fuel in the reactor pressure vessel (RPV) and with the water level < 22 ft 8 inches above the RPV flange both RHR shutdown cooling subsystems must be OPERABLE.

An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path.

(continued)

(9)

INSERT SR 3.10.2.1 and SR 3.10.2.2

In addition, the all rods fully inserted Surveillance (SR 3.10.2.1) must be verified by a second licensed operator (Reactor Operator or Senior Reactor Operator) or other qualified member of the technical staff (e.g., a qualified shift technical advisor or reactor engineer). (B)

BASES

LCO (continued)

function is not OPERABLE, or the CRD is to be removed, a sufficient number of rods in the vicinity of the withdrawn control rod are required to be inserted and made incapable of withdrawal (Item c.2). This precludes the possibility of criticality upon withdrawal of this control rod. Also, once this alternate (Item c.2) is completed, the SDM requirement to account for both the withdrawn-untrippable control rod and the highest worth control rod may be changed to allow the withdrawn-untrippable control rod to be the single highest worth control rod.

APPLICABILITY

Control rod withdrawals are adequately controlled in MODES 1, 2, and 5 by existing LCOs. In MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with Special Operations LCO 3.10.3, or this Special Operations LCO, and if limited to one control rod. This allowance is only provided with the reactor mode switch in the refuel position.

(10) LCO 3.3.8.2, "Reactor Protection System (RPS) Electric Power Monitoring,"

During these conditions, the full insertion requirements for all other control rods, the one-rod-out interlock (LCO 3.9.2), control rod position indication (LCO 3.9.4), and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and LCO 3.9.5, "Control Rod OPERABILITY – Refueling"), or the added administrative controls in Item b.2 and Item c.2 of this Special Operations LCO, provide mitigation of potential reactivity excursions. (B)

ACTIONS

A Note has been provided to modify the ACTIONS (4) related to a single control rod withdrawal while in MODE (3). Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

(continued)

BASES

ACTIONS

A.1 (continued)

fails to follow the drive as it is withdrawn (i.e., is "stuck" in an inserted position), placing the reactor mode switch in the shutdown position per Required Action B.1 could cause substantial secondary damage. If recoupling is not accomplished, operation may continue, provided the control rods are fully inserted within 3 hours and disarmed (electrically or hydraulically) within 4 hours. Inserting a control rod ensures the shutdown and scram capabilities are not adversely affected. The control rod is disarmed to prevent inadvertent withdrawal during subsequent operations. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically, the control rods can be disarmed by disconnecting power from all four directional control valve solenoids. Required Action A.1 is modified by a Note that allows ~~control rods~~ to be bypassed ~~in the Rod Action Control System (RACS)~~ if required to allow insertion of the inoperable control rods and continued operation. ~~SR 3.3.2.1.9~~ provides additional requirements when the ~~control rods are~~ bypassed to ensure compliance with the CRDA analysis.

The allowed Completion Times are reasonable, considering the small number of allowed inoperable control rods, and provide time to insert and disarm the control rods in an orderly manner and without challenging plant systems.

Condition A is modified by a Note allowing separate Condition entry for each uncoupled control rod. This is acceptable since the Required Actions for this Condition provide appropriate compensatory actions for each uncoupled control rod. Complying with the Required Actions may allow for continued operation. Subsequent uncoupled control rods are governed by subsequent entry into the Condition and application of the Required Actions.

B.1

With one or more of the requirements of this LCO not met for reasons other than an uncoupled control rod, the testing should be immediately stopped by placing the reactor mode switch in the shutdown or refuel position. This results in a condition that is consistent with the requirements for MODE 5 where the provisions of this Special Operations LCO are no longer required.

(continued)

BASES

ACTIONS (continued)

B.1

With the requirements of this LCO not met, the affected control rod shall be declared inoperable. This results in a condition that is consistent with the requirements for MODE 5 where the provisions of this Special Operations LCO are no longer required.

SURVEILLANCE REQUIREMENTS

SR 3.10.8.1, SR 3.10.8.2, and SR 3.10.8.3

LCO 3.3.1.1, Functions 2.a and 2.d, made applicable in this Special Operations LCO, are required to have applicable Surveillances met to establish that this Special Operations LCO is being met. However, the control rod withdrawal sequences during the SDM tests may be enforced by the RWM (LCO 3.3.2.1, Function 1, MODE 2 requirements) or by a second licensed operator or other qualified member of the technical staff. As noted, either the applicable SRs for the RWM (LCO 3.3.2.1) must be satisfied according to the applicable Frequencies (SR 3.10.8.2), or the proper movement of control rods must be verified (SR 3.10.8.3). This latter verification (i.e., SR 3.10.8.3) must be performed during control rod movement to prevent deviations from the specified sequence. These Surveillances provide adequate assurance that the specified test sequence is being followed.

SR 3.10.8.4

Periodic verification of the administrative controls established by this LCO will ensure that the reactor is operated within the bounds of the safety analysis. The 12 hour Frequency is intended to provide appropriate assurance that each operating shift is aware of and verifies compliance with these Special Operations LCO requirements.

SR 3.10.8.5

Coupling verification is performed to ensure the control rod is connected to the control rod drive mechanism and will perform its intended function when necessary. The

(continued)

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
BASES SECTION 3.10 - SPECIAL OPERATIONS

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

2. The proper LCO number has been provided.

3. Typographical/grammatical error corrected.

4. The hydrostatic test is already required at reactor coolant temperature > 200°F. Therefore, this sentence has been deleted.

5. This paragraph is considered an unnecessary level of detail for these Bases because the subject is adequately presented in the Bases for proposed LCO 3.4.12, "Reactor Coolant System (RCS) Pressure and Temperature (P/T) Limits." In addition, the last sentence is being deleted since the LCO is not exempting the Safety Limit from being met during a hydrostatic test.

6. The ASME inservice test does not require the SRVs to be gagged. Therefore, a valid reason for this LCO exception has been provided.

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

8. The Bases have been changed to be consistent with the Specification.

9. Editorial change made for enhanced clarity or to be consistent with similar statements in other places in the Bases.

10. The Bases have been changed to reflect those changes made to the Specification.

11. The correct power level (corresponding to the analysis value) is 10% RTP. As written, the power level corresponds to the low power setpoint, which is higher.

12. This Bases section has been deleted because the associated Specification has been deleted.

13. This statement has been deleted since it is duplicative of the previous sentence.

14. This change was approved to be made in NUREG-1434, Revision 1 per change package BWR-18, C.81, but apparently was not made. This change was made to the BWR/4 ITS, NUREG-1433, Revision 1. (13)