1.1 Definitions

DOSE EQUIVALENT I-131 (continued)	Power and Test Reactor Sites;" 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 throttle valve limit switch or from when the turbine governor valve hydraulic 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.
ISOLATION SYSTEM RESPONSE TIME	The ISOLATION SYSTEM RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its isolation initiation setpoint at the channel sensor until the isolation valves travel to their required positions. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. C C

(continued)

1.1 Definitions (continued)

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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, 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.

(continued)

1.1 Definitions

TURBINE BYPASS SYSTEM RESPONSE TIME (continued)	The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured.

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Function X subsystem inoperable.	A.1 Restore Function X subsystem to OPERABLE status.	7 days AND 10 days from discovery of failure to meet the LCO
B. One Function Y subsystem inoperable.	B.1 Restore Function Y subsystem to OPERABLE status.	72 hours AND 10 days from discovery of failure to meet the LCO
C. One Function X subsystem inoperable. AND One Function Y subsystem inoperable.	C.1 Restore Function X subsystem to OPERABLE status. OR C.2 Restore Function Y subsystem to OPERABLE status.	72 hours 72 hours

(continued)

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-5 (continued)

If the Completion Time associated with a valve in Condition A expires, Condition B is entered for that valve. If the Completion Times associated with subsequent valves in Condition A expire, Condition B is entered separately for each valve and separate Completion Times start and are tracked for each valve. If a valve that caused entry into Condition B is restored to OPERABLE status, Condition B is exited for that valve.

Since the Note in this example allows multiple Condition entry and tracking of separate Completion Times, Completion Time extensions do not apply.

EXAMPLE 1.3-6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One channel inoperable.	A.1 Perform SR 3.x.x.x. OR A.2 Reduce THERMAL POWER to ≤ 50% RTP.	Once per 8 hours 8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours

C

(continued)

3.0 LCO APPLICABILITY

LCO 3.0.4 (continued)

Exceptions to this Specification are stated in the individual Specifications. These exceptions allow entry into MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered allow unit operation in the MODE or other specified condition in the Applicability only for a limited period of time.

LCO 3.0.4 is only applicable for entry into a MODE or other specified condition in the Applicability in MODES 1, 2, and 3.

LCO 3.0.5

Equipment removed from service or declared inoperable to comply with ACTIONS may be returned to service under administrative control solely to perform testing required to demonstrate its OPERABILITY or the OPERABILITY of other equipment. This is an exception to LCO 3.0.2 for the system returned to service under administrative control to perform the testing required to demonstrate OPERABILITY. C C

LCO 3.0.6

When a supported system LCO is not met solely due to a support system LCO not being met, the Conditions and Required Actions associated with this supported system are not required to be entered. Only the support system LCO ACTIONS are required to be entered. This is an exception to LCO 3.0.2 for the supported system. In this event, additional evaluations and limitations may be required in accordance with Specification 5.5.11, "Safety Function Determination Program (SFDP)." 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.

When a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

(continued)

3.3 INSTRUMENTATION

3.3.1.1 Reactor Protection System (RPS) Instrumentation

LCO 3.3.1.1 The RPS instrumentation for each Function in Table 3.3.1.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1.1-1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip. OR A.2 Place associated trip system in trip.	12 hours 12 hours
B. One or more Functions with one or more required channels inoperable in both trip systems.	B.1 Place channel in one trip system in trip. OR B.2 Place one trip system in trip.	6 hours 6 hours
C. One or more Functions with RPS trip capability not maintained.	C.1 Restore RPS trip capability.	1 hour

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1	Enter the Condition referenced in Table 3.3.1.1-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1	Reduce THERMAL POWER to < 30% RTP.	4 hours
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1	Be in MODE 2.	6 hours
G. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1	Be in MODE 3.	12 hours
H. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	H.1	Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

-----NOTES-----

1. Refer to Table 3.3.1.1-1 to determine which SRs apply for each RPS 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 6 hours provided the associated Function maintains RPS trip capability.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.1.1.2	-----NOTE----- Not required to be performed until 12 hours after THERMAL POWER ≥ 25% RTP. ----- Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power ≤ 2% RTP plus any gain adjustment required by LCO 3.2.4, "Average Power Range Monitor (APRM) Gain and Setpoint," while operating at ≥ 25% RTP.	7 days
SR 3.3.1.1.3	-----NOTE----- Not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ----- Perform CHANNEL FUNCTIONAL TEST.	7 days
SR 3.3.1.1.4	Perform CHANNEL FUNCTIONAL TEST.	7 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.5	Verify the source range monitor (SRM) and intermediate range monitor (IRM) channels overlap.	Prior to withdrawing SRMs from the fully inserted position
SR 3.3.1.1.6	------------------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
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

1/B

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
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
SR 3.3.1.1.11	Verify the APRM Flow Biased Simulated Thermal Power—High Function time constant is ≤ 7 seconds.	18 months
SR 3.3.1.1.12	Verify Turbine Throttle Valve—Closure, and Turbine Governor Valve Fast Closure Trip Oil Pressure—Low Functions are not bypassed when THERMAL POWER is ≥ 30% RTP.	18 months
SR 3.3.1.1.13	Perform CHANNEL FUNCTIONAL TEST.	24 months
SR 3.3.1.1.14	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.15	-------------------NOTES------------------ 1. Neutron detectors are excluded. 2. For Function 5, "n" equals 4 channels for the purpose of determining the STAGGERED TEST BASIS Frequency. --- Verify the RPS RESPONSE TIME is within limits.	24 months on a STAGGERED TEST BASIS

1C

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Table 3.3.1.1-1 (page 1 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Intermediate Range Monitors					
a. Neutron Flux — High	2	3	G	SR 3.3.1.1.1 SR 3.3.1.1.3 SR 3.3.1.1.5 SR 3.3.1.1.6 SR 3.3.1.1.10 SR 3.3.1.1.14	≤ 122/125 divisions of full scale
	5(a)	3	H	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.10 SR 3.3.1.1.14	≤ 122/125 divisions of full scale
b. Inop	2	3	G	SR 3.3.1.1.3 SR 3.3.1.1.14	NA
	5(a)	3	H	SR 3.3.1.1.4 SR 3.3.1.1.14	NA
2. Average Power Range Monitors					
a. Neutron Flux — High, Setdown	2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.3 SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.9 SR 3.3.1.1.14	≤ 20% RTP
b. Flow Biased Simulated Thermal Power — High	1	2	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.7 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.11 SR 3.3.1.1.14	≤ 0.58W + 62% RTP and ≤ 114.9% RTP
c. Fixed Neutron Flux — High	1	2	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.7 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.14 SR 3.3.1.1.15	≤ 120% RTP
d. Inop	1,2	2	G	SR 3.3.1.1.7 SR 3.3.1.1.8 SR 3.3.1.1.14	NA
3. Reactor Vessel Steam Dome Pressure — High	1,2	2	G	SR 3.3.1.1.8 SR 3.3.1.1.10 SR 3.3.1.1.14 SR 3.3.1.1.15	≤ 1079 psig

(continued)

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2.1.1 Verify ≥ 12 rods withdrawn.	Immediately
	OR	
	C.2.1.2 Verify by administrative methods that startup with RWM inoperable has not been performed in the last calendar year.	Immediately
	AND	
	C.2.2 Verify movement of control rods is in compliance with banked position withdrawal sequence (BPWS) by a second licensed operator or other qualified member of the technical staff.	During control rod movement
D. RWM inoperable during reactor shutdown.	D.1 Verify movement of control rods is in compliance with BPWs by a second licensed operator or other qualified member of the technical staff.	During control rod movement

(continued)

Table 3.3.2.1-1 (page 1 of 1)
Control Rod Block Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Rod Block Monitor				
a. Upscale	(a)	2	SR 3.3.2.1.1 SR 3.3.2.1.4 SR 3.3.2.1.5	≤ 0.58W + 51% RTP
b. Inop	(a)	2	SR 3.3.2.1.1 SR 3.3.2.1.4	NA
c. Downscale	(a)	2	SR 3.3.2.1.1 SR 3.3.2.1.4 SR 3.3.2.1.5	≥ 3% RTP
2. Rod Worth Minimizer	$1^{(b)}, 2^{(b)}$	1	SR 3.3.2.1.2 SR 3.3.2.1.3 SR 3.3.2.1.6 SR 3.3.2.1.8	NA
3. Reactor Mode Switch — Shutdown Position	(c)	2	SR 3.3.2.1.7	NA

(a) THERMAL POWER ≥ 30% RTP and no peripheral control rod selected.

(b) With THERMAL POWER ≤ 10% RTP.

(c) Reactor mode switch in the shutdown position.

3.3 INSTRUMENTATION

3.3.3.1 Post Accident Monitoring (PAM) Instrumentation

LCO 3.3.3.1 The PAM instrumentation for each Function in Table 3.3.3.1-1 shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

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

1. LCO 3.0.4 is not applicable.

2. Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required channel inoperable.	A.1 Restore required channel to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Initiate action in accordance with Specification 5.6.6.	Immediately
C. One or more Functions with two or more required channels inoperable.	C.1 Restore all but one required channel to OPERABLE status.	7 days

(continued)

1C

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. Required Action and associated Completion Time of Condition C not met.	D.1	Enter the Condition referenced in Table 3.3.3.1-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.3.1-1.	E.1	Be in MODE 3.	12 hours
F. As required by Required Action D.1 and referenced in Table 3.3.3.1-1.	F.1	Initiate action in accordance with Specification 5.6.6.	Immediately

C

SURVEILLANCE REQUIREMENTS

NOTES

1. These SRs apply to each Function in Table 3.3.3.1-1.
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 6 hours provided the other required channel(s) in the associated Function is OPERABLE.

SURVEILLANCE		FREQUENCY
SR 3.3.3.1.1	Perform CHANNEL CHECK.	31 days

(continued)

3.3 INSTRUMENTATION

3.3.4.2 Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation

LCO 3.3.4.2 Two channels per trip system for each ATWS-RPT instrumentation Function listed below shall be OPERABLE:

a. Reactor Vessel Water Level — Low Low, Level 2; and

b. Reactor Vessel Steam Dome Pressure — High.

APPLICABILITY: MODE 1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Restore channel to OPERABLE status.	7 days
	OR	
	A.2 --------NOTE-------- Not applicable if inoperable channel is the result of an inoperable breaker. -------------------- Place channel in trip.	7 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.4.2.2	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.4.2.3	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. Reactor Vessel Water Level — Low Low, Level 2: ≥ -58 inches; and b. Reactor Vessel Steam Dome Pressure — High: ≤ 1143 psig.	18 months
SR 3.3.4.2.4	Perform LOGIC SYSTEM FUNCTIONAL TEST, including breaker actuation.	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
SR 3.3.5.1.6	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months
SR 3.3.5.1.7	Verify the ECCS RESPONSE TIME for each required ECCS injection/spray subsystem is within limits.	24 months on a STAGGERED TEST BASIS

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 SR 3.3.5.1.7	≥ -148 inches
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 SR 3.3.5.1.7	≤ 1.88 psig
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
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
e. LPCI Pump A Start — LOCA/LOOP Time Delay Relay	1,2,3, 4(a),5(a)	1	C	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.6	≥ 3.04 seconds and ≤ 6.00 seconds
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
	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
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
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
i. 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 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 SR 3.3.5.1.7	≥ -148 inches
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 SR 3.3.5.1.7	≤ 1.88 psig
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
e. LPCI Pump B Start — LOCA/LOOP Time Delay Relay	1,2,3, 4(a),5(a)	1	C	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.6	≥ 3.04 seconds and ≤ 6.00 seconds
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
	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
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
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 SR 3.3.5.1.7	≥ -58 inches

(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 SR 3.3.5.1.7	≤ 1.88 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 3.3.5.1.4 SR 3.3.5.1.6	≤ 56.0 inches
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
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
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
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. 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	≤ 115.0 seconds
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
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

(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
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	≥ 151.4 psig
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
b. 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	≤ 115.0 seconds
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
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
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	≥ 151.4 psig
f. Manual Initiation	1,2(d),3(d)	4	G	SR 3.3.5.1.6	NA

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

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.6.1-1 to determine which SRs apply for each Primary Containment Isolation 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 6 hours provided the associated Function maintains isolation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.6.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.6.1.2	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.6.1.3	Perform CHANNEL FUNCTIONAL TEST.	184 days
SR 3.3.6.1.4	Perform CHANNEL CALIBRATION.	18 months
SR 3.3.6.1.5	Perform CHANNEL CALIBRATION.	24 months
SR 3.3.6.1.6	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months
SR 3.3.6.1.7	Verify the ISOLATION SYSTEM RESPONSE TIME is within limits.	24 months on a STAGGERED TEST BASIS

C

Table 3.3.6.1-1 (page 2 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
3. Reactor Core Isolation Cooling (RCIC) System Isolation					
a. RCIC Steam Line Flow — High	1,2,3	1	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	≤ 250 inches wg
b. RCIC Steam Line Flow — Time Delay	1,2,3	1	F	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.6	≤ 3.00 seconds
c. RCIC Steam Supply Pressure — Low	1,2,3	2	F	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.6	≥ 61 psig
d. RCIC Turbine Exhaust Diaphragm Pressure — High	1,2,3	2	F	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.6	≤ 20 psig
e. RCIC Equipment Room Area Temperature — High	1,2,3	1	F	SR 3.3.6.1.3 SR 3.3.6.1.4 SR 3.3.6.1.6	≤ 180°F
f. RCIC Equipment Room Area Differential Temperature — High	1,2,3	1	F	SR 3.3.6.1.3 SR 3.3.6.1.4 SR 3.3.6.1.6	≤ 60°F
g. RWCU/RCIC Steam Line Routing Area Temperature — High	1,2,3	1	F	SR 3.3.6.1.3 SR 3.3.6.1.4 SR 3.3.6.1.6	≤ 180°F
h. Manual Initiation	1,2,3	1(b)	G	SR 3.3.6.1.6	NA
4. RWCU System Isolation					
a. Differential Flow — High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 67.4 gpm
b. Differential Flow — Time Delay	1,2,3	1	F	SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 46.5 seconds
c. Blowdown Flow — High	1,2,3	1	F	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 3.3.6.1.7	≤ 271.7 gpm

(continued)

(b) RCIC Manual Initiation only inputs into one of the two trip systems.

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	≤ 135 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.

Table 3.3.7.1-1 (page 1 of 1)
Control Room Emergency Filtration System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Reactor Vessel Water Level – Low Low, Level 2	1,2,3, (a)	2	B	SR 3.3.7.1.1 SR 3.3.7.1.2 SR 3.3.7.1.3 SR 3.3.7.1.4	≥ -58 inches
2. Drywell Pressure – High	1,2,3	2	C	SR 3.3.7.1.1 SR 3.3.7.1.2 SR 3.3.7.1.3 SR 3.3.7.1.4	≤ 1.88 psig
3. Reactor Building Vent Exhaust Plenum Radiation – High	1,2,3, (a),(b)	2	B	SR 3.3.7.1.1 SR 3.3.7.1.2 SR 3.3.7.1.3 SR 3.3.7.1.4	≤ 16.0 mR/hr
4. Main Control Room Ventilation Radiation Monitor	1,2,3, (a),(b)	2 per intake	E	SR 3.3.7.1.1 SR 3.3.7.1.2 SR 3.3.7.1.3	≤ 3800 cpm

C

(a) During operations with a potential for draining the reactor vessel.

(b) During CORE ALTERATIONS, and during movement of irradiated fuel assemblies in the secondary containment.

3.3 INSTRUMENTATION

3.3.8.1 Loss of Power (LOP) Instrumentation

LCO 3.3.8.1 The LOP instrumentation for each Function in Table 3.3.8.1-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
When the associated diesel generator (DG) is required to be OPERABLE by LCO 3.8.2, "AC Sources—Shutdown."

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Enter the Condition referenced in Table 3.3.8.1-1 for the channel.	Immediately
B. As required by Required Action A.1 and referenced in Table 3.3.8.1-1.	B.1 Declare associated DG inoperable.	1 hour from discovery of loss of initiation capability for the associated DG
	AND	
	B.2 Restore channel to OPERABLE status.	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. As required by Required Action A.1 and referenced in Table 3.3.8.1-1.	C.1 Place channel in trip.	1 hour
D. Required Action and associated Completion Time of Condition B or C not met.	D.1 Declare associated DG inoperable.	Immediately
	OR	
	------------NOTE------------- Only applicable for Functions 1.c and 1.d. ----------------------------	
	D.2.1 Open offsite circuit supply breaker to associated 4.16 kV ESF bus.	Immediately
	AND	
	D.2.2 Declare associated offsite circuit inoperable.	Immediately

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
SR 3.3.8.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months

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

FUNCTION	REQUIRED CHANNELS PER DIVISION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	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	2	B	SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 2450 V and ≤ 3135 V
b. TR-S Loss of Voltage — Time Delay	2	B	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 2.95 seconds and ≤ 7.1 seconds
c. TR-B Loss of Voltage — 4.16 kV Basis	1	C	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	C	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 3.06 seconds and ≤ 9.28 seconds
e. Degraded Voltage — 4.16 kV Basis	2[(a)]	C	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 3685 V and ≤ 3755 V
f. Degraded Voltage — Primary Time Delay	2[(a)]	C	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. Degraded Voltage — Secondary Time Delay	1	C	SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 2.63 seconds and ≤ 3.39 seconds
2. Division 3 - 4.16 kV Emergency Bus Undervoltage				
a. Loss of Voltage — 4.16 kV Basis	2	B	SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 2450 V and ≤ 3135 V
b. Loss of Voltage — Time Delay	2	B	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 1.87 seconds and ≤ 3.73 seconds
c. Degraded Voltage — 4.16 kV Basis	2	C	SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 3685 V and ≤ 3755 V
d. Degraded Voltage — Time Delay	2	C	SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 7.36 seconds and ≤ 8.34 seconds

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

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. B

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 B
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	Be in MODE 3.	12 hours
	<u>AND</u>		
	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.	Immediately
	<u>OR</u>		
	D.2	Initiate action to isolate the RHR SDC System.	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

B

SURVEILLANCE REQUIREMENTS

------------------------------------NOTE------------------------------------
When an RPS electric power monitoring assembly is placed in an inoperable status solely for performance of required Surveillances, entry into the 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.

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
SR 3.3.8.2.2	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. Overvoltage ≤ 133.8 V, with time delay ≤ 3.46 seconds; b. Undervoltage ≥ 110.8 V, with time delay ≤ 3.46 seconds; and c. Underfrequency ≥ 57 Hz, with time delay ≤ 3.46 seconds.	18 months
SR 3.3.8.2.3	Perform a system functional test.	18 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.2 Jet Pumps

LCO 3.4.2 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 3.4.2.1	-------------------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. -- 1C	
	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 recirculation pump speed 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 1C

3.4 REACTOR COOLANT SYSTEM (RCS)

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

LCO 3.4.3 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 3.4.3.1 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 3.4.3.2 Verify each required SRV opens when manually actuated.	24 months

 1C

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.4 Safety/Relief Valves (SRVs) — < 25% RTP 1C

LCO 3.4.4 The safety function of four SRVs shall be OPERABLE. 1C

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. <u>AND</u> A.2 Be in MODE 4.	12 hours 36 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 1C

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.4.2	------------------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

1C

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.5 RCS Operational LEAKAGE

LCO 3.4.5 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.	12 hours
	AND		
	C.2	Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.1	Verify RCS unidentified and total LEAKAGE and unidentified LEAKAGE increase are within limits.	12 hours

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 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 3.4.6.1 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 3.4.6.1	-------------------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

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.7 RCS Leakage Detection Instrumentation 1C

LCO 3.4.7 The following RCS leakage detection instrumentation shall be OPERABLE: 1C

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.	Once per 12 hours
	<u>AND</u>	
	B.2 Restore required drywell atmospheric monitoring system to OPERABLE status.	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.	12 hours
	AND		
	C.2	Be in MODE 4.	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 3.4.7.1	Perform CHANNEL CHECK of required drywell atmospheric monitoring system.	12 hours
SR 3.4.7.2	Perform CHANNEL FUNCTIONAL TEST of required leakage detection instrumentation.	31 days
SR 3.4.7.3	Perform CHANNEL CALIBRATION of required leakage detection instrumentation.	18 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.8 RCS Specific Activity

LCO 3.4.8 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.	Once per 4 hours
	AND	
	A.2 Restore DOSE EQUIVALENT I-131 to within limits.	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.	Once per 4 hours
	AND	
	B.2.1 Isolate all main steam lines.	12 hours
	OR	
		(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 3.4.8.1	-------------------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

1C

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.9 Residual Heat Removal (RHR) Shutdown Cooling System — Hot Shutdown | C

LCO 3.4.9 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. | C

---------------------------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 3.4.9.1	-------------------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)

3.4.10 Residual Heat Removal (RHR) Shutdown Cooling System — Cold Shutdown 1C

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. 1C

---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 <u>AND</u> 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.	1 hour from discovery of no reactor coolant circulation AND Once per 12 hours thereafter
	AND		
	B.2	Monitor reactor coolant temperature and pressure.	Once per hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.10.1	Verify one RHR shutdown cooling subsystem or recirculation pump is operating.	12 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.11 RCS Pressure and Temperature (P/T) Limits 1C

LCO 3.4.11 RCS pressure, RCS temperature, RCS heatup and cooldown rates, and the recirculation loop temperature requirements shall be maintained within limits. 1C 1C

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. AND A.2 Determine RCS is acceptable for continued operation.	30 minutes 72 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. ---------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.	Immediately
	<u>AND</u>		
	C.2	Determine RCS is acceptable for operation.	Prior to entering MODE 2 or 3

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.11.1	-------------------NOTE------------------- Only required to be performed during RCS heatup and cooldown operations, and RCS inservice leak and hydrostatic testing. --	
	Verify:	30 minutes
	a. RCS pressure and RCS temperature are within the applicable limits specified in Figures 3.4.11-1, 3.4.11-2, and 3.4.11-3;	
	b. RCS heatup and cooldown rates are ≤ 100°F in any 1 hour period; and	
	c. RCS temperature change during inservice leak and hydrostatic testing is ≤ 20°F in any 1 hour period when the RCS pressure and RCS temperature are not within the limits of Figure 3.4.11-2.	

C

C

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.11.2	Verify RCS pressure and RCS temperature are within the criticality limits specified in Figure 3.4.11-3.	Once within 15 minutes prior to control rod withdrawal for the purpose of achieving criticality
SR 3.4.11.3	-------------------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 ≤ 145°F.	Once within 15 minutes prior to each startup of a recirculation pump
SR 3.4.11.4	-------------------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 ≤ 50°F.	Once within 15 minutes prior to each startup of a recirculation pump

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.11.5	------------------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 ≤ 145°F.	Once within 15 minutes prior to an increase in THERMAL POWER or an increase in loop flow
SR 3.4.11.6	------------------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 ≤ 50°F.	Once within 15 minutes prior to an increase in THERMAL POWER or an increase in loop flow

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.11.7	-------------------NOTE------------------- Only required to be performed when tensioning the reactor vessel head bolting studs. -- Verify reactor vessel flange and head flange temperatures are ≥ 80°F.	30 minutes
SR 3.4.11.8	-------------------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 ≥ 80°F.	30 minutes
SR 3.4.11.9	-------------------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 ≥ 80°F.	12 hours

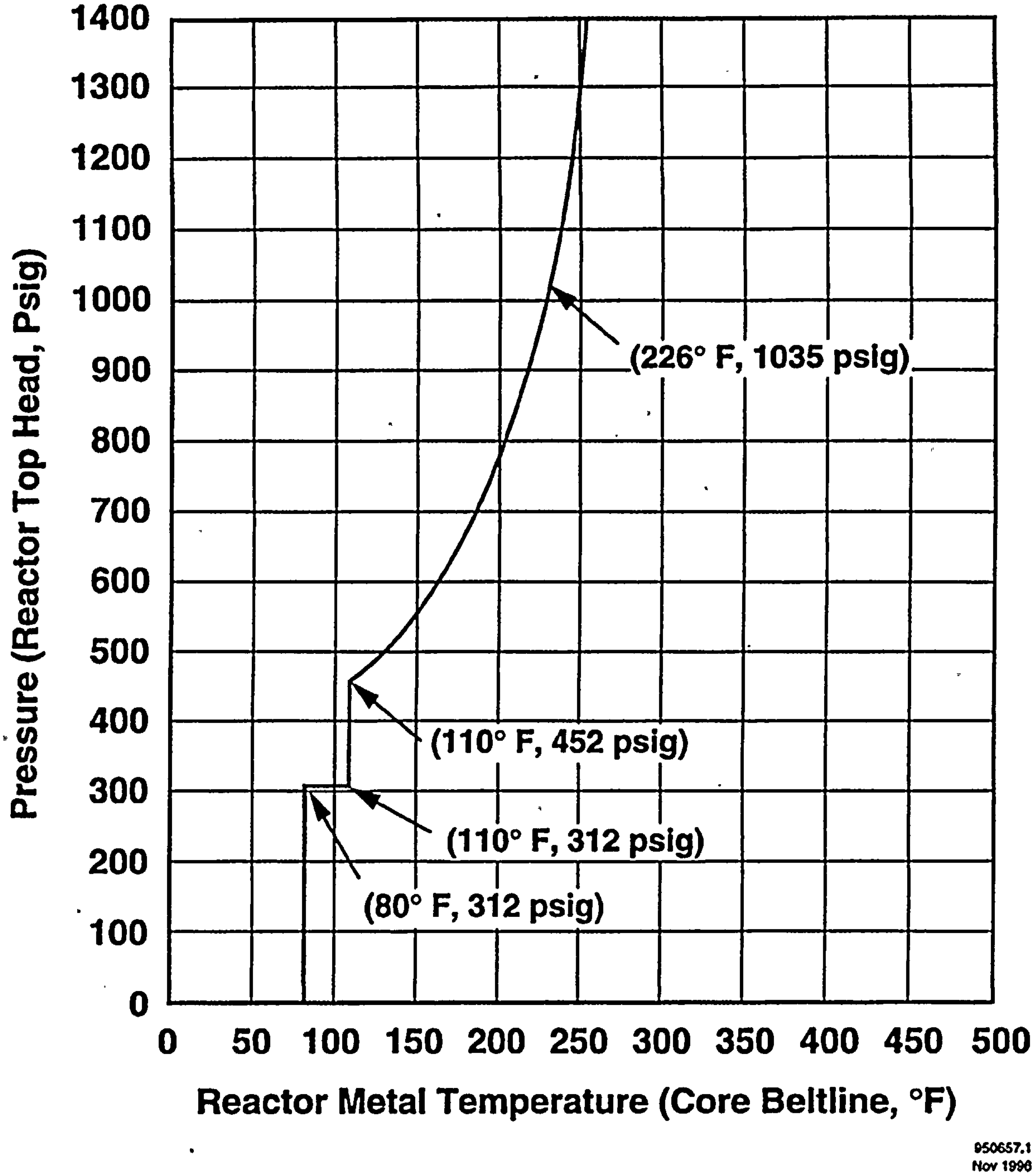

Figure 3.4.11-1 (Page 1 of 1)
Inservice Leak and Hydrostatic Testing Curve

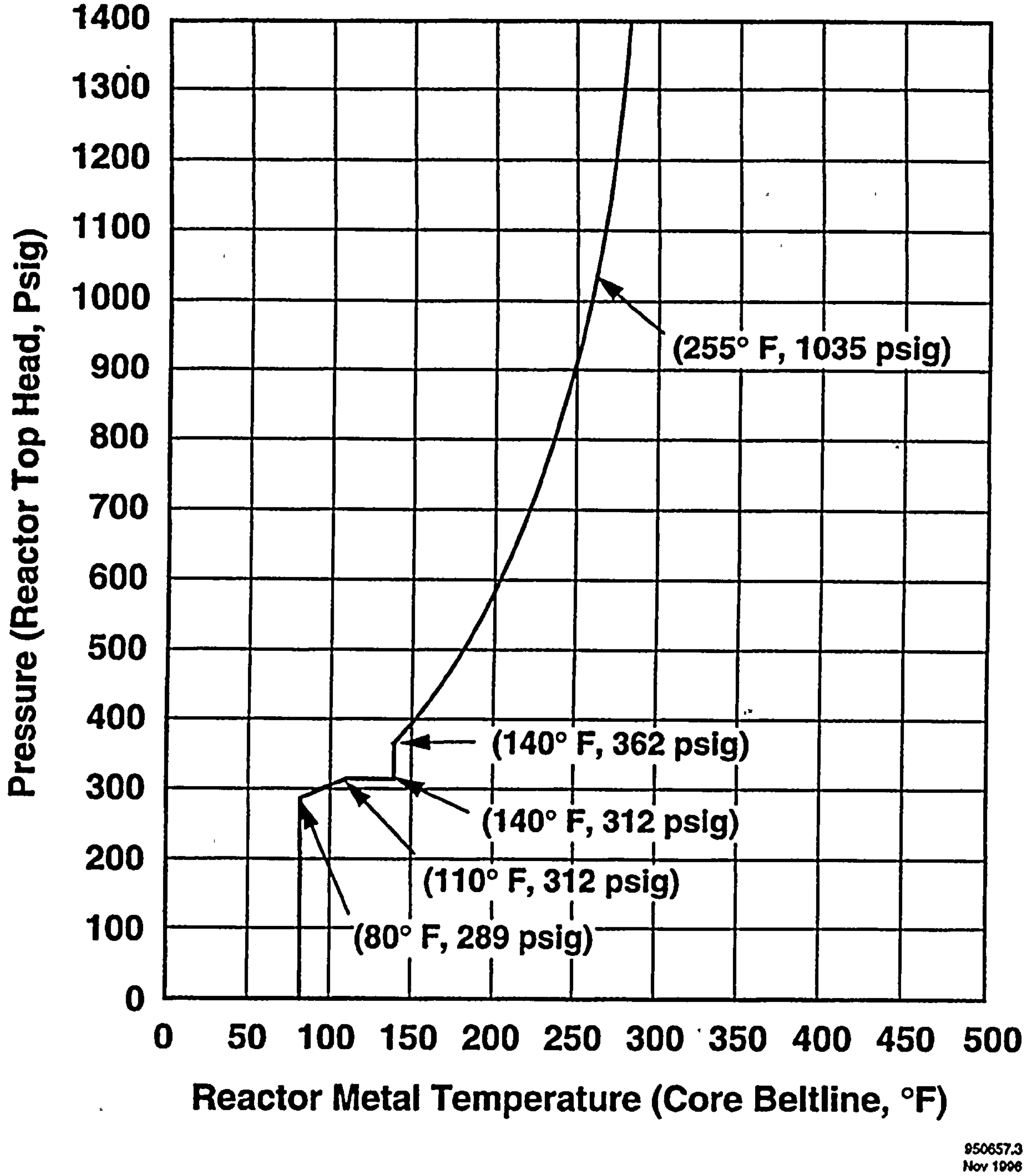

Figure 3.4.11-2 (Page 1 of 1)
Non-Nuclear Heating and Cooldown Curve

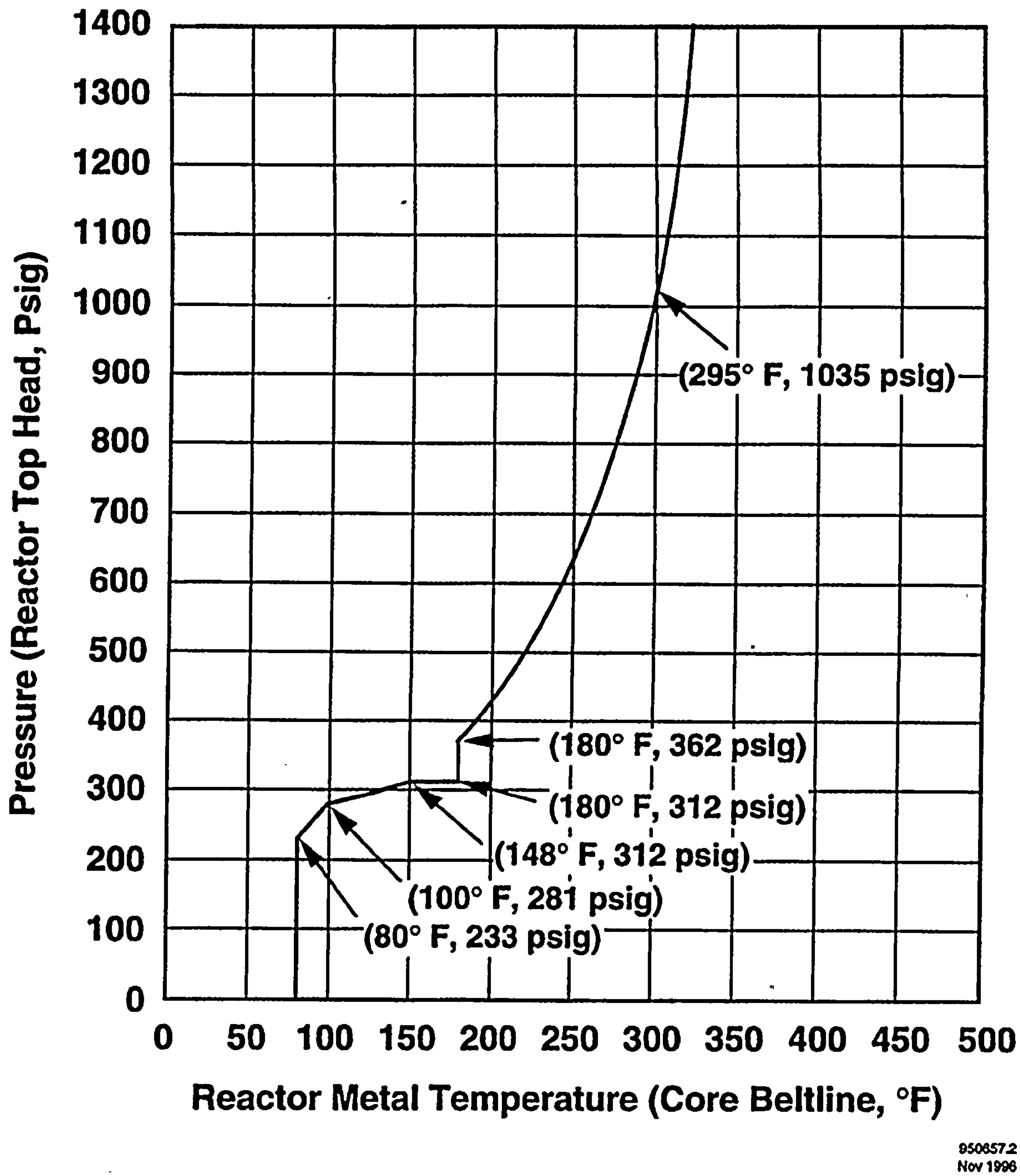

Figure 3.4.11-3 (Page 1 of 1)
Nuclear Heating and Cooldown Curve

C

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.12 Reactor Steam Dome Pressure

LCO 3.4.12 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 3.4.12.1 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.	7 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.	Immediately
	<u>AND</u>		
	B.2	Restore HPCS System to OPERABLE status.	14 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Two ECCS injection subsystems inoperable. OR One ECCS injection and one ECCS spray subsystem inoperable.	C.1	Restore one ECCS injection/spray subsystem to OPERABLE status.	72 hours
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1 AND D.2	Be in MODE 3. Be in MODE 4.	12 hours 36 hours
E. One required ADS valve inoperable.	E.1	Restore ADS valve to OPERABLE status.	14 days
F. One required ADS valve inoperable. AND One low pressure ECCS injection/spray subsystem inoperable.	F.1 OR F.2	Restore ADS valve to OPERABLE status. Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	72 hours 72 hours

(continued)

1C

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.1.4	Verify each ECCS pump develops the specified flow rate with the specified developed head. SYSTEM / FLOW RATE / TOTAL DEVELOPED HEAD LPCS / ≥ 6350 gpm / ≥ 128 psid LPCI / ≥ 7450 gpm / ≥ 26 psid HPCS / ≥ 6350 gpm / ≥ 200 psid	In accordance with the Inservice Testing Program
SR 3.5.1.5	-------------------NOTE------------------- Vessel injection/spray may be excluded. -- Verify each ECCS injection/spray subsystem actuates on an actual or simulated automatic initiation signal.	24 months
SR 3.5.1.6	-------------------NOTE------------------- Valve actuation may be excluded. -- Verify the ADS actuates on an actual or simulated automatic initiation signal.	24 months
SR 3.5.1.7	-------------------NOTE------------------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. -- Verify each required ADS valve opens when manually actuated.	24 months on a STAGGERED TEST BASIS for each valve solenoid

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

3.5.2 ECCS — Shutdown

LCO 3.5.2 Two ECCS injection/spray subsystems shall be OPERABLE.

APPLICABILITY: MODE 4,
MODE 5 except with the spent fuel storage pool gates removed and water level ≥ 22 ft over the top of the reactor pressure vessel flange.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required ECCS injection/spray subsystem inoperable.	A.1 Restore required ECCS injection/spray subsystem to OPERABLE status.	4 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Initiate action to suspend operations with a potential for draining the reactor vessel (OPDRVs).	Immediately
C. Two required ECCS injection/spray subsystems inoperable.	C.1 Initiate action to suspend OPDRVs. <u>AND</u> C.2 Restore one ECCS injection/spray subsystem to OPERABLE status.	Immediately 4 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action C.2 and associated Completion Time not met.	D.1 Initiate action to restore secondary containment to OPERABLE status. <u>AND</u> D.2 Initiate action to restore one standby gas treatment subsystem to OPERABLE status. <u>AND</u> D.3 Initiate action to restore isolation capability in each required secondary containment penetration flow path not isolated.	Immediately Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.1	Verify, for each required low pressure ECCS injection/spray subsystem, the suppression pool water level is ≥ 18 ft 6 inches.	12 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.2.2	Verify, for the required High Pressure Core Spray (HPCS) System, the: a. Suppression pool water level is ≥ 18 ft 6 inches; or b. Condensate storage tank (CST) water level is ≥ 13.25 ft in a single CST or ≥ 7.6 ft in each CST.	12 hours
SR 3.5.2.3	Verify, for each required ECCS injection/spray subsystem, the piping is filled with water from the pump discharge valve to the injection valve.	31 days
SR 3.5.2.4	-------------------NOTE------------------- One low pressure coolant injection (LPCI) subsystem may be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned and not otherwise inoperable. -- Verify each required ECCS injection/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.	31 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.2.5	Verify each required ECCS pump develops the specified flow rate with the specified developed head. SYSTEM / FLOW RATE / TOTAL DEVELOPED HEAD LPCS / ≥ 6350 gpm / ≥ 128 psid LPCI / ≥ 7450 gpm / ≥ 26 psid HPCS / ≥ 6350 gpm / ≥ 200 psid	In accordance with the Inservice Testing Program
SR 3.5.2.6	-------------------NOTE-------------------- Vessel injection/spray may be excluded. -- Verify each required ECCS injection/spray subsystem actuates on an actual or simulated automatic initiation signal.	24 months

C

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

3.5.3 RCIC System

LCO 3.5.3 The RCIC System shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3 with reactor steam dome pressure > 150 psig.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. RCIC System inoperable.	A.1	Verify by administrative means High Pressure Core Spray System is OPERABLE.	Immediately
	<u>AND</u>		
	A.2	Restore RCIC System to OPERABLE status.	14 days
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	12 hours
	<u>AND</u>		
	B.2	Reduce reactor steam dome pressure to ≤ 150 psig.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.3.1	Verify the RCIC System piping is filled with water from the pump discharge valve to the injection valve.	31 days
SR 3.5.3.2	Verify each RCIC System 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.	31 days
SR 3.5.3.3	-------------------NOTE------------------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. -- Verify, with reactor pressure ≤ 1035 psig and ≥ 935 psig, the RCIC pump can develop a flow rate ≥ 600 gpm against a system head corresponding to reactor pressure.	92 days
SR 3.5.3.4	-------------------NOTE------------------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. -- Verify, with reactor pressure ≤ 165 psig, the RCIC pump can develop a flow rate ≥ 600 gpm against a system head corresponding to reactor pressure.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.3.5	-------------------NOTE-------------------- Vessel injection may be excluded. --- Verify the RCIC System actuates on an actual or simulated automatic initiation signal.	24 months

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. One or more penetration flow paths with secondary containment bypass leakage rate, MSIV leakage rate, or hydrostatically tested lines leakage rate not within limit.	D.1	Restore leakage rate to within limit.	4 hours except for main steam line AND 8 hours for main steam line
E. Required Action and associated Completion Time of Condition A, B, C, or D not met in MODE 1, 2, or 3.	E.1	Be in MODE 3.	12 hours
	AND		
	E.2	Be in MODE 4.	36 hours
F. Required Action and associated Completion Time of Condition A, B, C, or D not met for PCIV(s) required to be OPERABLE during MODE 4 or 5.	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

C

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. 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.	12 hours
	AND		
	D.2	Be in MODE 4.	36 hours

1C

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)

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. Required Action and associated Completion Time of Condition A not met. OR Two RHR suppression pool cooling subsystems inoperable.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

C

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One SW subsystem inoperable.	B.1	--------NOTES-------- 1. Enter applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources—Operating," for diesel generator made inoperable by SW System. 2. Enter applicable Conditions and Required Actions of LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown," for RHR shutdown cooling subsystem made inoperable by SW System. -------------------- Restore SW subsystem to OPERABLE status.	72 hours

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2	Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.	24 hours from discovery of no offsite power to one division concurrent with inoperability of redundant required feature(s)
	AND		
	A.3	Restore offsite circuit to OPERABLE status.	72 hours AND 6 days from discovery of failure to meet LCO
B. One required DG inoperable.	B.1	Perform SR 3.8.1.1 for OPERABLE offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.2	Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	<u>AND</u>		
	B.3.1	Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	<u>OR</u>		
	B.3.2	Perform SR 3.8.1.2 for OPERABLE DG(s).	24 hours
	<u>AND</u>		
	B.4	Restore required DG to OPERABLE status.	72 hours <u>AND</u> 6 days from discovery of failure to meet LCO

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. Two required DGs inoperable.	E.1	Restore one required DG to OPERABLE status.	2 hours OR 24 hours if Division 3 DG is inoperable
F. Required Action and Associated Completion Time of Condition A, B, C, D, or E not met.	F.1	Be in MODE 3.	12 hours
	AND		
	F.2	Be in MODE 4.	36 hours
G. Three or more required AC sources inoperable.	G.1	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each offsite circuit.	7 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	-----NOTES----- 1. This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. 2. If performed with the DG synchronized with offsite power, it shall be performed at a power factor as close to the power factor of the single largest post-accident load as practicable. ---------- Verify each required DG rejects a load greater than or equal to its associated single largest post-accident load, and following load rejection, the frequency is ≤ 66.75 Hz.	24 months
SR 3.8.1.10	-----NOTES----- 1. This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. 2. If performed with the DG synchronized with offsite power, it shall be performed at the accident load power factor, or at a power factor as close to the accident load power factor as practicable with the field excitation current ≥ 90% of the continuous rating. ---------- Verify each required DG does not trip and voltage is maintained ≤ 4784 V during and following a load rejection of a load ≥ 4400 kW for DG-1 and DG-2 and ≥ 2600 kW for DG-3.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	------------------NOTES------------------ 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. --- Verify on an actual or simulated loss of offsite power signal: a. De-energization of emergency buses; b. Load shedding from emergency buses for Divisions 1 and 2; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 15 seconds for DG-1 and DG-2, and in ≤ 18 seconds for DG-3, 2. energizes auto-connected shutdown loads, 3. maintains steady state voltage ≥ 3740 V and ≤ 4400 V, 4. maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected shutdown loads for ≥ 5 minutes.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	-------------------NOTES------------------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. ---	
	Verify on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal each required DG auto-starts from standby condition and: a. For DG-1 and DG-2, in ≤ 15 seconds achieves voltage ≥ 3910 V, and after steady state conditions are reached, maintains voltage ≥ 3910 V and ≤ 4400 V and, for DG-3, in ≤ 15 seconds achieves voltage ≥ 3740 V, and after steady state conditions are reached, maintains voltage ≥ 3740 V and ≤ 4400 V; b. In ≤ 15 seconds, achieves frequency ≥ 58.8 Hz and after steady state conditions are achieved, maintains frequency ≥ 58.8 Hz and ≤ 61.2 Hz; c. Operates for ≥ 5 minutes; d. Permanently connected loads remain energized from the offsite power system; and e. Emergency loads are auto-connected to the offsite power system.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.13	------------------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's automatic trips are bypassed on an actual or simulated ECCS initiation signal except: a. Engine overspeed; b. Generator differential current; and c. Incomplete starting sequence.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.14	-------------------NOTES------------------- 1. Momentary transients outside the load, excitation current, and power factor ranges do not invalidate this test. 2. This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. 3. If performed with the DG synchronized with offsite power, it shall be performed at the accident load power factor, or at a power factor as close to the accident load power factor as practicable with the field excitation current ≥ 90% of the continuous rating. ---	
	Verify each required DG operates for ≥ 24 hours: a. For ≥ 2 hours loaded ≥ 4650 kW for DG-1 and DG-2, and ≥ 2850 kW for DG-3; and b. For the remaining hours of the test loaded ≥ 4400 kW for DG-1 and DG-2, and ≥ 2600 kW for DG-3.	24 months

(continued)

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)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
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
SR 3.8.1.17	-------------------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, with a DG operating in test mode and connected to its bus, an actual or simulated ECCS initiation signal overrides the test mode by: a. Returning DG to ready-to-load operation; and b. Automatically energizing the emergency load from offsite power.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.18	------------------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 interval between each sequenced load block is within ± 10% of design interval for each time delay relay.	24 months
SR 3.8.1.19	------------------NOTES------------------ 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. -- Verify, on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ECCS initiation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses for DG-1 and DG-2; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 15 seconds, 2. energizes auto-connected emergency loads, 3. maintains steady state voltage ≥ 3740 V and ≤ 4400 V,	24 months (continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.19	(continued) 4. maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected emergency loads for ≥ 5 minutes.	
SR 3.8.1.20	-------------------NOTE-------------------- All DG starts may be preceded by an engine prelube period. -- Verify, when started simultaneously from standby condition, DG-1 and DG-2 achieves, in ≤ 15 seconds, voltage ≥ 3910 V and frequency ≥ 58.8 Hz, and DG-3 achieves, in ≤ 15 seconds, voltage ≥ 3740 V and frequency ≥ 58.8 Hz.	10 years

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.

ACTIONS

------------------------------------NOTE------------------------------------
LCO 3.0.3 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required offsite circuit inoperable.	------------NOTE------------ Enter applicable Condition and Required Actions of LCO 3.8.8, when any required division is de-energized as a result of Condition A. ----------------------------	
	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 secondary containment.	Immediately
	AND	
	A.2.3 Initiate action to suspend operations with a potential for draining the reactor vessel (OPDRVs).	Immediately
	AND	
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2.4	Initiate action to restore required offsite power circuit to OPERABLE status.	Immediately
B. Division 1 or 2 required DG inoperable.	B.1	Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>		
	B.2	Suspend movement of irradiated fuel assemblies in secondary containment.	Immediately
	<u>AND</u>		
	B.3	Initiate action to suspend OPDRVs.	Immediately
	<u>AND</u>		
	B.4	Initiate action to restore required DG to OPERABLE status.	Immediately
C. Required Division 3 DG inoperable.	C.1	Declare High Pressure Core Spray System inoperable.	72 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.2.1	-------------------NOTE------------------- The following SRs are not required to be performed: SR 3.8.1.3, SR 3.8.1.9 through SR 3.8.1.11, SR 3.8.1.13 through SR 3.8.1.16, SR 3.8.1.18, and SR 3.8.1.19. -- For AC sources required to be OPERABLE, the SRs of Specification 3.8.1, except SR 3.8.1.8, SR 3.8.1.17, and SR 3.8.1.20, are applicable.	In accordance with applicable SRs

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. <u>OR</u> 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

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.3.1	Verify each fuel oil storage tank contains: a. ≥ 55,500 gal of fuel for DG-1 and DG-2; and b. ≥ 33,000 gal of fuel for DG-3.	31 days
SR 3.8.3.2	Verify lube oil inventory is: a. ≥ 330 gal for DG-1 and DG-2; and b. ≥ 165 gal for DG-3.	31 days
SR 3.8.3.3	Verify fuel oil properties of new and stored fuel oil are tested in accordance with, and maintained within the limits of, the Diesel Fuel Oil Testing Program.	In accordance with the Diesel Fuel Oil Testing Program
SR 3.8.3.4	Verify each required DG air start receiver pressure is: a. ≥ 230 psig for DG-1 and DG-2; and b. ≥ 223 psig for DG-3.	31 days
SR 3.8.3.5	Check for and remove accumulated water from each fuel oil storage tank.	92 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources—Operating

LCO 3.8.4 The Division 1, Division 2, and Division 3 DC electrical power subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Division 1 or 2 125 V DC electrical power subsystem inoperable.	A.1	Restore Division 1 and 2 125 V DC electrical power subsystems to OPERABLE status.	2 hours
B. Division 3 DC electrical power subsystem inoperable.	B.1	Declare High Pressure Core Spray System inoperable.	Immediately
C. Division 1 250 V DC electrical power subsystem inoperable.	C.1	Declare associated supported features inoperable.	Immediately
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	12 hours
	<u>AND</u>		
	D.2	Be in MODE 4.	36 hours

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 $\leq$ 24.4 E-6 ohms for inter-cell connectors of the Division 1 and 2 batteries, $\leq$ 169 E-6 ohms for inter-cell connectors of the Division 3 battery, and $\leq$ 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 $\geq$ 1.5 hours at: a. $\geq$ 126 V for the 125 V battery chargers; and b. $\geq$ 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

3.8 ELECTRICAL POWER SYSTEMS

3.8.5 DC Sources — Shutdown

LCO 3.8.5 DC electrical power subsystem(s) shall be OPERABLE to support the electrical power distribution subsystem(s) required by LCO 3.8.8, "Distribution Systems — Shutdown."

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

ACTIONS

-----------------------------------NOTE-----------------------------------
LCO 3.0.3 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required DC electrical power subsystems inoperable.	A.1 Declare affected required feature(s) inoperable.	Immediately
	<u>OR</u>	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	A.2.2 Suspend movement of irradiated fuel assemblies in the secondary containment.	Immediately
	<u>AND</u>	
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.3 Initiate action to suspend operations with a potential for draining the reactor vessel.	Immediately
	AND	
	A.2.4 Initiate action to restore required DC electrical power subsystems to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.5.1	-------------------NOTE------------------- The following SRs are not required to be performed: SR 3.8.4.7 and SR 3.8.4.8. -- For DC electrical power subsystems required to be OPERABLE the following SRs are applicable: SR 3.8.4.1, SR 3.8.4.2, SR 3.8.4.3, SR 3.8.4.4, SR 3.8.4.5, SR 3.8.4.6, SR 3.8.4.7, and SR 3.8.4.8.	In accordance with applicable SRs

3.8 ELECTRICAL POWER SYSTEMS

3.8.6 Battery Cell Parameters

LCO 3.8.6 Battery cell parameters for the Division 1, 2, and 3 batteries shall be within the limits of Table 3.8.6-1.

APPLICABILITY: When associated DC electrical power subsystems are required to be OPERABLE.

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more batteries with one or more battery cell parameters not within Category A or B limits.	A.1	Verify pilot cell(s) electrolyte level and float voltage meet Table 3.8.6-1 Category C limits.	1 hour
	<u>AND</u>		
	A.2	Verify battery cell parameters meet Table 3.8.6-1 Category C limits.	24 hours <u>AND</u> Once per 7 days thereafter
	<u>AND</u>		
	A.3	Restore battery cell parameters to Category A and B limits of Table 3.8.6-1.	31 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met. OR One or more batteries with average electrolyte temperature of the representative cells ≤ 60°F. OR One or more batteries with one or more battery cell parameters not within Category C limits.	B.1 Declare associated battery inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.8.6.1 Verify battery cell parameters meet Table 3.8.6-1 Category A limits.	7 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.6.2	Verify battery cell parameters meet Table 3.8.6-1 Category B limits.	92 days AND Once within 24 hours after battery discharge < 110 V for 125 V batteries and < 220 V for the 250 V battery AND Once within 24 hours after battery overcharge > 150 V for 125 V batteries and > 300 V for the 250 V battery
SR 3.8.6.3	Verify average electrolyte temperature of representative cells is > 60°F.	92 days

Table 3.8.6-1 (page 1 of 1)
Battery Cell Parameter Requirements

PARAMETER	CATEGORY A: LIMITS FOR EACH DESIGNATED PILOT CELL	CATEGORY B: LIMITS FOR EACH CONNECTED CELL	CATEGORY C: LIMITS FOR EACH CONNECTED CELL
Electrolyte Level	> Minimum level indication mark, and ≤ ¼ inch above maximum level indication mark[a]	> Minimum level indication mark, and ≤ ¼ inch above maximum level indication mark[a]	Above top of plates, and not overflowing
Float Voltage	≥ 2.13 V	≥ 2.13 V	> 2.07 V
Specific Gravity[b][c]	≥ 1.200	≥ 1.195 <u>AND</u> Average of all connected cells > 1.205	Not more than 0.020 below average of all connected cells <u>AND</u> Average of all connected cells ≥ 1.195

(a) It is acceptable for the electrolyte level to temporarily increase above the specified maximum level during and following equalizing charges provided it is not overflowing.

(b) Corrected for electrolyte temperature and level. Level correction is not required, however, when battery charging is < 2 amps when on float charge.

(c) A battery charging current of < 2 amps when on float charge is acceptable for meeting specific gravity limits following a battery recharge, for a maximum of 7 days. When charging current is used to satisfy specific gravity requirements, specific gravity of each connected cell shall be measured prior to expiration of the 7 day allowance.

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Distribution Systems — Operating

LCO 3.8.7 The following AC and DC electrical power distribution subsystems shall be OPERABLE:

a. Division 1 and Division 2 AC electrical power distribution subsystems;

b. Division 1 and Division 2 125 V DC electrical power distribution subsystems;

c. Division 1 250 V DC electrical power distribution subsystem; and

d. Division 3 AC and DC electrical power distribution subsystems.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Division 1 or 2 AC electrical power distribution subsystem inoperable.	A.1	Restore Division 1 and 2 AC electrical power distribution subsystems to OPERABLE status.	8 hours AND 16 hours from discovery of failure to meet LCO 3.8.7.a or b

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. Division 1 or 2 125 V DC electrical power distribution subsystem inoperable.	B.1	Restore Division 1 and 2 125 V DC electrical power distribution subsystems to OPERABLE status.	2 hours AND 16 hours from discovery of failure to meet LCO 3.8.7.a or b
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 AND C.2	Be in MODE 3. Be in MODE 4.	12 hours 36 hours
D. Division 1 250 V DC electrical power distribution subsystem inoperable.	D.1	Declare associated supported feature(s) inoperable.	Immediately
E. One or more Division 3 AC or DC electrical power distribution subsystems inoperable.	E.1	Declare High Pressure Core Spray System inoperable.	Immediately
F. Two or more divisions with inoperable electrical power distribution subsystems that result in a loss of function.	F.1	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.7.1	Verify correct breaker alignments and indicated power availability to required AC and DC electrical power distribution subsystems.	7 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.8 Distribution Systems — Shutdown

LCO 3.8.8 The necessary portions of the Division 1, Division 2, and Division 3 AC and DC electrical power distribution subsystems shall be OPERABLE to support equipment required to be OPERABLE.

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

ACTIONS

------------------------------------NOTE------------------------------------
LCO 3.0.3 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required AC or DC electrical power distribution subsystems inoperable.	A.1 Declare associated supported required feature(s) inoperable.	Immediately
	<u>OR</u>	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	A.2.2 Suspend movement of irradiated fuel assemblies in the secondary containment.	Immediately
	<u>AND</u>	
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.3 Initiate action to suspend operations with a potential for draining the reactor vessel.	Immediately
	AND	
	A.2.4 Initiate actions to restore required AC and DC electrical power distribution subsystems to OPERABLE status.	Immediately
	AND	
	A.2.5 Declare associated required shutdown cooling subsystem(s) inoperable and not in operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.8.1	Verify correct breaker alignments and indicated power availability to required AC and DC electrical power distribution subsystems.	7 days

3.10 SPECIAL OPERATIONS

3.10.1 Inservice Leak and Hydrostatic Testing Operation

LCO 3.10.1 The average reactor coolant temperature specified in Table 1.1-1 for MODE 4 may be changed to "NA," and operation considered not to be in MODE 3; and the requirements of LCO 3.4.10, "Residual Heat Removal (RHR) Shutdown Cooling System—Cold Shutdown," may be suspended, to allow performance of an inservice leak or hydrostatic test provided the following MODE 3 LCOs are met: 1C

a. LCO 3.3.6.2, "Secondary Containment Isolation Instrumentation," Functions 1, 3, and 4 of Table 3.3.6.2-1;

b. LCO 3.6.4.1, "Secondary Containment";

c. LCO 3.6.4.2, "Secondary Containment Isolation Valves (SCIVs)"; and

d. LCO 3.6.4.3, "Standby Gas Treatment (SGT) System."

APPLICABILITY: MODE 4 with average reactor coolant temperature > 200°F.

5.0 ADMINISTRATIVE CONTROLS

5.2 Organization

5.2.1 Onsite and Offsite Organizations

Onsite and offsite organizations shall be established for unit operation and corporate management, respectively. The onsite and offsite organizations shall include the positions for activities affecting safety of the nuclear power plant.

a. Lines of authority, responsibility, and communication shall be defined and established throughout highest management levels, intermediate levels, and all operating organization positions. These relationships shall be documented and updated, as appropriate, in organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements shall be documented in the FSAR.

b. The Plant General Manager shall be responsible for overall safe operation of the plant and shall have control over those onsite activities necessary for safe operation and maintenance of the plant.

c. The Chief Executive Officer shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety. | C

d. The individuals who train the operating staff, carry out health physics, or perform quality assurance functions may report to the appropriate onsite manager; however, these individuals shall have sufficient organizational freedom to ensure their independence from operating pressures.

5.2.2 Unit Staff

The unit staff organization shall include the following:

a. At least two Equipment Operators shall be assigned when the unit is in MODE 1, 2, or 3; and at least one Equipment Operator shall be assigned when the unit is in MODE 4 or 5.

(continued)

5.0 ADMINISTRATIVE CONTROLS

5.3 Unit Staff Qualifications

5.3.1 Each member of the unit staff shall meet or exceed the minimum qualifications of ANSI/ANS N18.1-1971, for comparable positions described in the FSAR, except for:

a. The Operations Manager, who shall meet the requirements of ANSI/ANS N18.1-1971 with the exception that in lieu of meeting the stated ANSI/ANS requirement to hold a Senior Reactor Operator (SRO) license at the time of appointment to the position, the Operations Manager shall:

1. Hold an SRO license at the time of appointment;

2. Have held an SRO license; or

3. Have been certified for equivalent SRO knowledge; and

b. The Radiation Protection Manager, who shall meet or exceed the qualifications of Regulatory Guide 1.8, Revision 1-R, May 1977.

C

5.0 ADMINISTRATIVE CONTROLS

5.5 Programs and Manuals

The following programs shall be established, implemented, and maintained.

5.5.1 Offsite Dose Calculation Manual (ODCM)

a. The ODCM shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring alarm and trip setpoints, and in the conduct of the radiological environmental monitoring program; and

b. The ODCM shall also contain the radioactive effluent controls and radiological environmental monitoring activities, and descriptions of the information that should be included in the Annual Radiological Environmental Operating and Radioactive Effluent Release reports required by Specification 5.6.2 and Specification 5.6.3.

c. Licensee initiated changes to the ODCM:

1. Shall be documented and records of reviews performed shall be retained. This documentation shall contain:

   (a) Sufficient information to support the change(s) together with the appropriate analyses or evaluations justifying the change(s), and

   (b) A determination that the change(s) maintain the levels of radioactive effluent control required pursuant to 10 CFR 20.1302, 40 CFR 190, 10 CFR 50.36a, and 10 CFR 50, Appendix I, and do not adversely impact the accuracy or reliability of effluent, dose, or setpoint calculations; | C

2. Shall become effective after review and acceptance by the Plant Operations Committee and the approval of the Plant General Manager; and

(continued)

5.5 Programs and Manuals

5.5.3 <u>Post Accident Sampling</u> (continued)

c. Provisions for maintenance of sampling and analysis equipment.

5.5.4 <u>Radioactive Effluent Controls Program</u>

This program, conforming to 10 CFR 50.36a, provides for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents as low as reasonably achievable. The program shall be contained in the ODCM, shall be implemented by procedures, and shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements: | C

a. Limitations on the functional capability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM;

b. Limitations on the concentrations of radioactive material released in liquid effluents from the site to unrestricted areas, conforming to 10 times the concentration values in Appendix B, Table 2, Column 2 to 10 CFR 20.1001 - 20.2402; | C

c. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents pursuant to 10 CFR 20.1302 and with the methodology and parameters in the ODCM; | C

d. Limitations on the annual and quarterly doses or dose commitment to a member of the public from radioactive materials in liquid effluents released from each unit to unrestricted areas, conforming to 10 CFR 50, Appendix I;

e. Determination of cumulative and projected dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days;

f. Limitations on the functional capability and use of the liquid and gaseous effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a period of 31 days would exceed 2% of the guidelines for the annual dose or dose commitment, conforming to 10 CFR 50, Appendix I;

(continued)

5.5 Programs and Manuals

5.5.7 Ventilation Filter Testing Program (VFTP) (continued)

after any structural maintenance on the system housing; and, following significant painting, fire, or chemical release in any ventilation zone communicating with the system while it is in operation.

Tests described in Specification 5.5.7.c shall be performed once per 24 months; after 720 hours of system operation; after any structural maintenance on the system housing; and, following significant painting, fire, or chemical release in any ventilation zone communicating with the system while it is in operation.

Tests described in Specification 5.5.7.d and 5.5.7.e shall be performed once per 24 months.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the VFTP test Frequencies.

a. Demonstrate for each of the ESF systems that an inplace test of the high efficiency particulate air (HEPA) filters 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: | E

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: | E

ESF Ventilation System	Flowrate (cfm)
SGT System	4012 to 4902
CREF System	900 to 1100

(continued)

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, 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:

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 ASME N510-1989:

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 applicable ASTM Standards. The purpose of the program is to establish the following: C

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, if gravity was not determined by comparison with the supplier's certificate, and a flash point within limits for ASTM 2-D fuel oil, C

(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 in accordance with ASTM D-2276, Method A-2 or A-3. C

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)

5.0 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) for whom monitoring was performed, receiving an annual deep dose equivalent of > 100 mrems and the associated collective deep dose equivalent (reported in man-rem) 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 20.2206. 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

(continued)

5.6 Reporting Requirements

5.6.2 Annual Radiological Environmental Operating Report (continued)

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

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:

(continued)

5.6 Reporting Requirements

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

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;

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

5. 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;

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

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

8. 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;

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

10. 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;

11. CENPD-300-P-A, "Reference Safety Report for Boiling Water Reactor Reload Fuel," July 1996; and

(continued)

5.6 Reporting Requirements

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

12. WPPSS-FTS-131(A), Revision 1, "Applications Topical Report for BWR Design and Analysis," March 1996.

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 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. 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;

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 <u>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)</u> (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. B

5.7.2 <u>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)</u>

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 or equipment entry or exit. C

(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 (whether alone or in a group) entering such an area shall possess: C

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, while in the area, 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 C

(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, and with the means to communicate with and control every individual in the area; or C 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.

VOLUME 3

BASES

BACKGROUND (continued)

reduction in heat transfer coefficient. Inside the steam film, high cladding temperatures are reached, and a cladding water (zirconium water) reaction may take place. This chemical reaction results in oxidation of the fuel cladding to a structurally weaker form. This weaker form may lose its integrity, resulting in an uncontrolled release of activity to the reactor coolant.

The reactor vessel water level SL ensures that adequate core cooling capability is maintained during all MODES of reactor operation. Establishment of Emergency Core Cooling System initiation setpoints higher than this safety limit provides margin such that the safety limit will not be reached or exceeded.

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation and AOOs. The reactor core SLs are established to preclude violation of the fuel design criterion that a MCPR limit is to be established, such that at least 99.9% of the fuel rods in the core would not be expected to experience the onset of transition boiling.

The Reactor Protection System setpoints (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), in combination with other LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System water level, pressure, and THERMAL POWER level that would result in reaching the MCPR limit.

2.1.1.1 Fuel Cladding Integrity

The use of the ANFB correlation is valid for critical power calculations at pressures > 600 psia and < 1500 psia and bundle mass fluxes > 0.1×10^6 lb/hr-ft^2 and < 1.5×10^6 lb/hr-ft^2 (Ref. 2). The use of the XL-S96 correlation is valid for critical power calculations at pressures > 392 psia and < 1262 psia and bundle mass fluxes > 0.25×10^6 lb/hr-ft^2 and < 1.55×10^6 lb/hr-ft^2 (Ref. 3). C
For operation at low pressures or low flows, the fuel cladding integrity SL is established by a limiting condition on core THERMAL POWER, with the following basis:

Provided that the water level in the vessel downcomer is maintained above the top of the active fuel, natural circulation is sufficient to ensure a minimum

(continued)

BASES

APPLICABLE SAFETY ANALYSES

2.1.1.1 Fuel Cladding Integrity (continued)

bundle flow for all fuel assemblies that have a relatively high power and potentially can approach a critical heat flux condition. The minimum bundle flow is > 28×10^3 lb/hr. The coolant minimum bundle flow and maximum flow area are such that the mass flux is > 0.25×10^6 lb/hr-ft^2. Full scale critical power tests taken at pressures down to 14.7 psia indicate that the fuel assembly critical power at 0.25×10^6 lb/hr-ft^2 is approximately 3.35 MWt. At 25% RTP, a bundle power of approximately 3.35 Mwt corresponds to a bundle radial peaking factor of > 2.9, which is significantly higher than the expected peaking factor. Thus, a THERMAL POWER limit of 25% RTP for reactor pressures < 785 psig is conservative.

2.1.1.2 MCPR

The MCPR SL ensures sufficient conservatism in the operating MCPR limit that, in the event of an AOO from the limiting condition of operation, at least 99.9% of the fuel rods in the core would be expected to avoid boiling transition. The margin between calculated boiling transition (i.e., MCPR = 1.00) and the MCPR SL is based on a detailed statistical procedure that considers the uncertainties in monitoring the core operating state. One specific uncertainty included in the SL is the uncertainty inherent in the critical power correlations. Reference 4 describes the methodology used in determining the MCPR SL for Siemens Power Corporation fuel. Reference 5 describes the methodology used in determining the MCPR SL for ABB CENO fuel.

The critical power correlations are based on a significant body of practical test data, providing a high degree of assurance that the critical power, as evaluated by the correlation, is within a small percentage of the actual critical power. As long as the core pressure and flow are within the range of validity of the critical power correlations, the assumed reactor conditions used in defining the SL introduce conservatism into the limit because bounding high radial power factors and bounding flat local peaking distributions are used to estimate the number

(continued)

BASES

APPLICABLE SAFETY ANALYSES

2.1.1.2 MCPR (continued)

of rods in boiling transition. This conservatism and the inherent accuracy of the critical power correlations provide a reasonable degree of assurance that there would be no transition boiling in the core during sustained operation at the MCPR SL. If boiling transition were to occur, there is reason to believe that the integrity of the fuel would not be compromised. Significant test data accumulated by the NRC and private organizations indicate that the use of a boiling transition limitation to protect against cladding failure is a very conservative approach. Much of the data indicate that BWR fuel can survive for an extended period of time in an environment of boiling transition.

2.1.1.3 Reactor Vessel Water Level

During MODES 1 and 2, the reactor vessel water level is required to be above the top of the active irradiated fuel to provide core cooling capability. With fuel in the reactor vessel during periods when the reactor is shut down, consideration must be given to water level requirements due to the effect of decay heat. If the water level should drop below the top of the active irradiated fuel during this period, the ability to remove decay heat is reduced. This reduction in cooling capability could lead to elevated cladding temperatures and clad perforation in the event that the water level becomes < 2/3 of the core height. The reactor vessel water level SL has been established at the top of the 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 prevent 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.

(continued)

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. 6). 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.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10.
2. ANF-1125(P)(A), Revision 0, including Supplements 1 and 2, April 1990.
3. UR-89-210-P-A, "SVEA-96 Critical Power Experiments on a Full Scale 24-Rod Sub-Bundle," October 1993.
4. ANF-524(P)(A), Revision 2, including Supplements 1 and 2, November 1990.
5. CENPD-300-P-A, "Reference Safety Report for Boiling Water Reactor Reload Fuel," July 1996.
6. 10 CFR 100.

BASES

LCO 3.0.2 (continued)

ACTIONS.) The second type of Required Action specifies the remedial measures that permit continued operation of the unit that is not further restricted by the Completion Time. In this case, compliance with the Required Actions provides an acceptable level of safety for continued operation.

Completing the Required Actions is not required when an LCO is met or is no longer applicable, unless otherwise stated in the individual Specifications.

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even though the associated Condition no longer exists. The individual LCO's ACTIONS specify the Required Actions where this is the case. An example of this is in LCO 3.4.11, "RCS Pressure and Temperature (P/T) Limits." | C

The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. The reasons for intentionally relying on the ACTIONS include, but are not limited to, performance of Surveillances, preventive maintenance, corrective maintenance, or investigation of operational problems. Entering ACTIONS for these reasons must be done in a manner that does not compromise safety. Intentional entry into ACTIONS should not be made for operational convenience. Alternatives that would not result in redundant equipment being inoperable should be used instead. Doing so limits the time both subsystems/divisions of a safety function are inoperable and limits the time other conditions exist which result in LCO 3.0.3 being entered. Individual Specifications may specify a time limit for performing an SR when equipment is removed from service or bypassed for testing. In this case, the Completion Times of the Required Actions are applicable when this time limit expires, if the equipment remains removed from service or bypassed.

When a change in MODE or other specified condition is required to comply with Required Actions, the unit may enter a MODE or other specified condition in which another Specification becomes applicable. In this case, the Completion Times of the associated Required Actions would apply from the point in time that the new Specification becomes applicable and the ACTIONS Condition(s) are entered.

(continued)

BASES

LCO 3.0.4 (continued)

The provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown.

Exceptions to LCO 3.0.4 are stated in the individual Specifications. Exceptions may apply to all the ACTIONS or to a specific Required Action of a Specification.

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by SR 3.0.1. Therefore, changing MODES or other specified conditions while in an ACTIONS Condition, either in compliance with LCO 3.0.4, or where an exception to LCO 3.0.4 is stated, is not a violation of SR 3.0.1 or SR 3.0.4 for those Surveillances that do not have to be performed due to the associated inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected LCO.

LCO 3.0.4 is only applicable when entering MODE 3 from MODE 4, MODE 2 from MODE 3 or 4, or MODE 1 from MODE 2. Furthermore, LCO 3.0.4 is applicable when entering any other specified condition in the Applicability only while operating in MODE 1, 2, or 3. The requirements of LCO 3.0.4 do not apply in MODES 4 and 5, or in other specified conditions of the Applicability (unless in MODE 1, 2, or 3) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

LCO 3.0.5

LCO 3.0.5 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONS. The sole purpose of this Specification is to provide an exception to LCO 3.0.2 (e.g., to not comply with the applicable Required Action(s)) to allow the performance of SRs to demonstrate:

a. The OPERABILITY of the equipment being returned to service; or | C

b. The OPERABILITY of other equipment. | C

(continued)

BASES

LCO 3.0.5 (continued)

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the allowed SRs. This Specification does not provide time to perform any other preventive or corrective maintenance.

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that has been closed to comply with Required Actions, and must be reopened to perform the SRs.

An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of an SR on another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of an SR on another channel in the same trip system. | C

LCO 3.0.6

LCO 3.0.6 establishes an exception to LCO 3.0.2 for support systems that have an LCO specified in the Technical Specifications (TS). This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system's LCO be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the plant is maintained in a safe condition are specified in the support system's LCO's Required Actions. These Required Actions may include entering the supported system's Conditions and Required Actions or may specify other Required Actions.

When a support system is inoperable and there is an LCO specified for it in the TS, the supported system(s) are required to be declared inoperable if determined to be inoperable as a result of the support system inoperability. However, it is not necessary to enter into the supported systems' Conditions and Required Actions unless directed to do so by the support system's Required Actions. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported

(continued)

BASES

LCO 3.0.6 (continued)

related to the entry into multiple support and supported systems' LCO's Conditions and Required Actions are eliminated by providing all the actions that are necessary to ensure the plant is maintained in a safe condition in the support system's Required Actions.

However, there are instances where a support system's Required Action may either direct a supported system to be declared inoperable or direct entry into Conditions and Required Actions for the supported system. This may occur immediately or after some specified delay to perform some other Required Action. Regardless of whether it is immediate or after some delay, when a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

Specification 5.5.11, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system Conditions and Required Actions. The SFDP implements the requirements of LCO 3.0.6.

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

LCO 3.0.7

There are certain special tests and operations required to be performed at various times over the life of the unit. These special tests and operations are necessary to demonstrate select unit performance characteristics, to perform special maintenance activities, and to perform

(continued)

BASES

LCO 3.0.7 (continued)

special evolutions. Special Operations LCOs in Section 3.10 allow specified TS requirements to be changed to permit performances of these special tests and operations, which otherwise could not be performed if required to comply with the requirements of these TS. Unless otherwise specified, all the other TS requirements remain unchanged. This will ensure all appropriate requirements of the MODE or other specified condition not directly associated with or required to be changed to perform the special test or operation will remain in effect.

The Applicability of a Special Operations LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with Special Operations LCOs is optional. A special operation may be performed either under the provisions of the appropriate Special Operations LCO or under the other applicable TS requirements. If it is desired to perform the special operation under the provisions of the Special Operations LCO, the requirements of the Special Operations LCO shall be followed. When a Special Operations LCO requires another LCO to be met, only the requirements of the LCO statement are required to be met regardless of that LCO's Applicability (i.e., should the requirements of this other LCO not be met, the ACTIONS of the Special Operations LCO apply, not the ACTIONS of the other LCO). However, there are instances where the Special Operations LCO's ACTIONS may direct the other LCO's ACTIONS be met. The Surveillances of the other LCO are not required to be met, unless specified in the Special Operations LCO. If conditions exist such that the Applicability of any other LCO is met, all the other LCO's requirements (ACTIONS and SRs) are required to be met concurrent with the requirements of the Special Operations LCO.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Rod Pattern Control

BASES

BACKGROUND

Control rod patterns during startup conditions are controlled by the operator and the rod worth minimizer (RWM) (LCO 3.3.2.1, "Control Rod Block Instrumentation"), so that only specified control rod sequences and relative positions are allowed over the operating range of all control rods inserted to 10% RTP. The sequences effectively limit the potential amount of reactivity addition that could occur in the event of a control rod drop accident (CRDA).

This Specification assures that the control rod patterns are consistent with the assumptions of the CRDA analyses of References 1, 2, and 3.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the CRDA are summarized in References 1, 2, 3, and 4. CRDA analyses assume that the reactor operator follows prescribed withdrawal sequences. These sequences define the potential initial conditions for the CRDA analysis. The RWM (LCO 3.3.2.1) provides backup to operator control of the withdrawal sequences to ensure that the initial conditions of the CRDA analysis are not violated.

Prevention or mitigation of positive reactivity insertion events is necessary to limit the energy deposition in the fuel, thereby preventing significant fuel damage, which could result in undue release of radioactivity. Since the failure consequences for UO_2 have been shown to be insignificant below fuel energy depositions of 300 cal/gm (Ref. 5), the fuel damage limit of 280 cal/gm provides a margin of safety from significant core damage, which would result in release of radioactivity (Refs. 6 and 7). Generic evaluations (Refs. 8 and 9) of a design basis CRDA (i.e., a CRDA resulting in a peak fuel energy deposition of 280 cal/gm) have shown that if the peak fuel enthalpy remains below 280 cal/gm, then the maximum reactor pressure will be less than the required ASME Code limits (Ref. 10) and the calculated offsite doses will be well within the required limits (Ref. 7).

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BASES

APPLICABLE SAFETY ANALYSES (continued)

Control rod patterns analyzed in Reference 1 follow the banked position withdrawal sequence (BPWS) described in Reference 11. The BPWS is applicable from the condition of all control rods fully inserted to 10% RTP (Ref. 2). For the BPWS, the control rods are required to be moved in groups, with all control rods assigned to a specific group required to be within specified banked positions (e.g., between notches 08 and 12). The banked positions are defined to minimize the maximum incremental control rod worths without being overly restrictive during normal plant operation. The generic BPWS analysis (Ref. 11) also evaluated the effect of fully inserted, inoperable control rods not in compliance with the sequence, to allow a limited number (i.e., eight) and distribution of fully inserted, inoperable control rods.

Rod pattern control satisfies the requirements of Criterion 3 of the NRC Policy Statement (Ref. 12).

LCO

Compliance with the prescribed control rod sequences minimizes the potential consequences of a CRDA by limiting the initial conditions to those consistent with the BPWS. This LCO only applies to OPERABLE control rods. For inoperable control rods required to be inserted, separate requirements are specified in LCO 3.1.3, "Control Rod OPERABILITY," consistent with the allowances for inoperable control rods in the BPWS.

APPLICABILITY

In MODES 1 and 2, when THERMAL POWER is ≤ 10% RTP, the CRDA is a Design Basis Accident (DBA) and, therefore, compliance with the assumptions of the safety analysis is required. When THERMAL POWER is > 10% RTP, there is no credible control rod configuration that results in a control rod worth that could exceed the 280 cal/gm fuel damage limit during a CRDA (Ref. 2). In MODES 3, 4, and 5, since the reactor is shut down and only a single control rod can be withdrawn from a core cell containing fuel assemblies, adequate SDM ensures that the consequences of a CRDA are acceptable, since the reactor will remain subcritical with a single control rod withdrawn.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

a second licensed operator (Reactor Operator or Senior Reactor Operator) or by a qualified member of the technical staff (e.g., a qualified shift technical advisor or reactor engineer).

With nine or more OPERABLE control rods not in compliance with BPWS, the reactor mode switch must be placed in the shutdown position within 1 hour. With the reactor mode switch in shutdown, the reactor is shut down, and therefore does not meet the applicability requirements of this LCO. The allowed Completion Time of 1 hour is reasonable to allow insertion of control rods to restore compliance, and is appropriate relative to the low probability of a CRDA occurring with the control rods out of sequence.

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

The control rod pattern is verified to be in compliance with the BPWS at a 24 hour Frequency, ensuring the assumptions of the CRDA analyses are met. The 24 hour Frequency of this Surveillance was developed considering that the primary check of the control rod pattern compliance with the BPWS is performed by the RWM (LCO 3.3.2.1). The RWM provides control rod blocks to enforce the required control rod sequence and is required to be OPERABLE when operating at ≤ 10% RTP.

REFERENCES

1. CE-NPSD-803-P, "WNP-2 Cycle 12 Reload Report," May 1996.

2. Letter from T.A. Pickens (BWROG) to G.C. Laines (NRC), "Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A," BWROG-8644, August 15, 1988.

3. FSAR, Section 15.F.4.3.

4. CENPD-284-P-A, "Control Rod Drop Accident Analysis Methodology for Boiling Water Reactors: Summary and Qualification," July 1996.

5. NUREG-0979, "NRC Safety Evaluation Report for GESSAR II BWR/6 Nuclear Island Design, Docket No. 50-447," Section 4.2.1.3.2, April 1983.

(continued)

BASES

REFERENCES (continued)

6. NUREG-0800, "Standard Review Plan," Section 15.4.9, "Radiological Consequences of Control Rod Drop Accident (BWR)," Revision 2, July 1981.

7. 10 CFR 100.11, "Determination of Exclusion Area Low Population Zone and Population Center Distance."

8. NEDO-10527, "Rod Drop Accident Analysis for Large BWRs," (including Supplements 1 and 2), March 1972.

9. NEDO-21778-A, "Transient Pressure Rises Affected Fracture Toughness Requirements for Boiling Water Reactors," December 1978.

10. ASME, Boiler and Pressure Vessel Code, Section III.

11. NEDO-21231, "Banked Position Withdrawal Sequence," January 1977.

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

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.7 Standby Liquid Control (SLC) System

BASES

BACKGROUND

The SLC System is designed to provide the capability of bringing the reactor, at any time in a fuel cycle, from full power and minimum control rod inventory (which is at the peak of the xenon transient) to a subcritical condition with the reactor in the most reactive xenon free state without taking credit for control rod movement. The SLC System satisfies the requirements of 10 CFR 50.62 (Ref. 1) on anticipated transient without scram (ATWS).

The SLC System consists of a boron solution storage tank, two positive displacement pumps, two explosive valves, which are provided in parallel for redundancy, and associated piping and valves used to transfer borated water from the storage tank to the reactor pressure vessel (RPV). The borated solution is discharged through the high pressure core spray system sparger.

APPLICABLE SAFETY ANALYSES

The SLC System is manually initiated from the main control room, as directed by the emergency operating procedures, if the operator believes the reactor cannot be shut down, or kept shut down, with the control rods. The SLC System is used in the event that not enough control rods can be inserted to accomplish shutdown and cooldown in the normal manner. The SLC System injects borated water into the reactor core to compensate for all of the various reactivity effects that could occur during plant operation. To meet this objective, it is necessary to inject, using both SLC pumps, a quantity of boron that produces a concentration of 660 ppm of natural boron in the reactor core, including recirculation loops, at 70°F and normal reactor water level. To allow for potential leakage and imperfect mixing in the reactor system, an additional amount of boron equal to 25% of the amount cited above is added (Ref. 2). An additional 275 ppm is provided to accommodate dilution in the RPV by the residual heat removal shutdown cooling piping. The temperature versus concentration limits in Figure 3.1.7-1 are calculated such that the required concentration is achieved. This quantity of borated solution is the amount that is above the pump suction shutoff level in the boron solution storage tank. No credit is taken for the portion of the tank volume that cannot be injected. | 1

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	operation to ensure the SDV has sufficient capacity to contain the reactor coolant discharge during a full core scram. To automatically ensure this capacity, a reactor scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation") is initiated if the SDV water level exceeds a specified setpoint. The setpoint is chosen such that all control rods are inserted before the SDV has insufficient volume to accept a full scram. SDV vent and drain valves satisfy Criterion 3 of the NRC Policy Statement (Ref. 4).
LCO	The OPERABILITY of all SDV vent and drain valves ensures that, during a scram, the SDV vent and drain valves will close to contain reactor water discharged to the SDV piping. Since the vent and drain lines are provided with two valves in series, the single failure of one valve in the open position will not impair the isolation function of the system. Additionally, the valves are required to be open to ensure that a path is available for the SDV piping to drain freely at other times.
APPLICABILITY	In MODES 1 and 2, scram may be required, and therefore, the SDV vent and drain valves must be OPERABLE. In MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. During MODE 5, only a single control rod can be withdrawn from a core cell containing fuel assemblies. Therefore, the SDV vent and drain valves are not required to be OPERABLE in these MODES since the reactor is subcritical and only one rod may be withdrawn and subject to scram.
ACTIONS	The ACTIONS Table is modified by a Note indicating that a separate Condition entry is allowed for each SDV vent and drain line. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable SDV line. Complying with the Required Actions may allow for continued operation, and subsequent inoperable SDV lines are governed by subsequent Condition entry and application of associated Required Actions.

(continued)

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)

BASES

BACKGROUND	The APLHGR is a measure of the average LHGR of all the fuel rods in a fuel assembly at any axial location. Limits on the APLHGR are specified to ensure that the fuel design limits identified in References 1, 2, and 3 are not exceeded and that the peak cladding temperature (PCT) during the postulated design basis loss of coolant accident (LOCA) does not exceed the limits specified in 10 CFR 50.46. As a result, core geometry will be maintained by minimizing gross fuel cladding failure due to heatup following a design basis LOCA.
APPLICABLE SAFETY ANALYSES	The analytical methods and assumptions used in evaluating the fuel design limits are presented in References 1 and 2. The analytical methods and assumptions used in evaluating Design Basis Accidents (DBAs) and normal operations that determine APLHGR limits are presented in FSAR, Chapters 4, 6, 15, and 15.F and in References 1, 2, 3, 4, and 5. |C LOCA analyses are performed to ensure that the specified APLHGR limits are adequate to meet the PCT and maximum oxidation limits of 10 CFR 50.46. The analysis is performed using calculational models that are consistent with the requirements of 10 CFR 50, Appendix K. A complete discussion of the analysis code is provided in References 1 and 5. The PCT following a postulated LOCA is a function of the average heat generation rate of all the rods of a fuel assembly at any axial location and is not strongly influenced by the rod to rod power distribution within an assembly. The APLHGR limits specified are equivalent to the LHGR of the highest powered fuel rod assumed in the LOCA analysis divided by its local peaking factor. A conservative multiplier is applied to the LHGR assumed in the LOCA analysis to account for the uncertainty associated with the measurement of the APLHGR. For single recirculation loop operation, References 1 and 2 show that no APLHGR reduction is required. |C The APLHGR satisfies Criterion 2 of the NRC Policy Statement (Ref. 6). |C

(continued)

BASES (continued)

LCO	The APLHGR limits specified in the COLR are the result of the fuel design and design basis accident analyses. Limits have been provided in the COLR for two recirculation loop operation and single recirculation loop operation. The limits on single recirculation loop operation are provided to allow operation in this condition in conformance with the requirements of LCO 3.4.1, "Recirculation Loops Operating."
APPLICABILITY	The APLHGR limits are primarily derived from fuel design evaluations and LOCA analyses that are assumed to occur at high power levels. Studies and operating experience have shown that as power is reduced, the margin to the required APLHGR limits increases. This trend continues down to the power range of 5% to 15% RTP when entry into MODE 2 occurs, thereby effectively removing any APLHGR limit compliance concern in MODE 2. Therefore, at THERMAL POWER levels ≤ 25% RTP, the reactor operates with substantial margin to the APLHGR limits; thus, this LCO is not required.

ACTIONS

A.1

If any APLHGR exceeds the required limits, an assumption regarding an initial condition of the DBA analyses may not be met. Therefore, prompt action is taken to restore the APLHGR(s) to within the required limits such that the plant will be operating within analyzed conditions and within the design limits of the fuel rods. The 2 hour Completion Time is sufficient to restore the APLHGR(s) to within its limits and is acceptable based on the low probability of a DBA occurring simultaneously with the APLHGR out of specification.

B.1

If the APLHGR cannot be restored to within its required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < 25% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 25% RTP in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1

APLHGRs are required to be initially calculated within 12 hours after THERMAL POWER is ≥ 25% RTP and then every 24 hours thereafter. They are compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 24 hour Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution under normal conditions. The 12 hour allowance after THERMAL POWER ≥ 25% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels.

REFERENCES

1. NEDC-32115P, "SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," Revision 2, June 1993.
2. CE-NPSD-803-P, "WNP-2 Cycle 12 Reload Report," May 1996.
3. XN-NF-80-19(A), "Exxon Nuclear Methodology for Boiling Water Reactors," Volumes 2, 2A, 2B, and 2C, September 1982.
4. CENPD-300-P-A, "Reference Safety Report for Boiling Water Reactor Reload Fuel," July 1996.
5. CE-NPSD-801-P, "WNP-2 LOCA Analysis Report," May 1996.
6. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.2 MINIMUM CRITICAL POWER RATIO (MCPR)

BASES

BACKGROUND

MCPR is a ratio of the fuel assembly power that would result in the onset of boiling transition to the actual fuel assembly power. The MCPR Safety Limit (SL) is set such that 99.9% of the fuel rods avoid boiling transition if the limit is not violated (refer to the Bases for SL 2.1.1.2). The operating limit MCPR is established to ensure that no fuel damage results during anticipated operational occurrences (AOOs). Although fuel damage does not necessarily occur if a fuel rod actually experiences boiling transition (Refs. 1 and 2), the critical power at which boiling transition is calculated to occur has been adopted as a fuel design criterion.

The onset of transition boiling is a phenomenon that is readily detected during the testing of various fuel bundle designs. Based on these experimental data, correlations have been developed to predict critical bundle power (i.e., the bundle power level at the onset of transition boiling) for a given set of plant parameters (e.g., reactor vessel pressure, flow, and subcooling). Because plant operating conditions and bundle power levels are monitored and determined relatively easily, monitoring the MCPR is a convenient way of ensuring that fuel failures due to inadequate cooling do not occur.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the AOOs to establish the operating limit MCPR are presented in the FSAR, Chapters 4, 6, and 15, and References 2, 3, and 4. To ensure that the MCPR SL is not exceeded during any transient event that occurs with moderate frequency, limiting transients have been analyzed to determine the largest reduction in critical power ratio (CPR). The types of transients evaluated are loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease. The limiting transient yields the largest change in CPR (ΔCPR). When the largest ΔCPR is added to the MCPR SL, the required operating limit MCPR is obtained.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The MCPR operating limits derived from the transient analysis are dependent on the operating core flow and power state ($MCPR_f$ and $MCPR_p$, respectively) to ensure adherence to fuel design limits during the worst transient that occurs with moderate frequency as identified in FSAR, Chapters 15 and 15.F.

Flow dependent MCPR limits are determined by steady state methods using the three dimensional BWR simulator code (Ref. 2). $MCPR_f$ curves are provided based on the maximum credible flow runout transient for ASD operation (i.e., runout of both loops). C

Power dependent MCPR limits ($MCPR_p$) are determined by the three dimensional BWR simulator code and the one dimensional transient code (Ref. 2). Due to the sensitivity of the transient response to initial core flow levels at power levels below those at which the turbine stop valve closure and turbine control valve fast closure scram trips are bypassed, high and low flow $MCPR_p$ operating limits are provided for operating between 25% RTP and the previously mentioned bypass power level. C C

The MCPR satisfies Criterion 2 of the NRC Policy Statement (Ref. 5). C

LCO

The MCPR operating limits specified in the COLR are the result of the Design Basis Accident (DBA) and transient analysis. The MCPR operating limits are determined by the larger of the $MCPR_f$ and $MCPR_p$ limits.

APPLICABILITY

The MCPR operating limits are primarily derived from transient analyses that are assumed to occur at high power levels. Below 25% RTP, the reactor is operating at a slow recirculation pump speed and the moderator void ratio is small. Surveillance of thermal limits below 25% RTP is unnecessary due to the large inherent margin that ensures that the MCPR SL is not exceeded even if a limiting transient occurs.

Statistical analyses indicate that the nominal value of the initial MCPR at 25% RTP is expected to be very large. Studies of the variation of limiting transient behavior have

(continued)

BASES

APPLICABILITY (continued)

been performed over the range of power and flow conditions. These studies encompass the range of key actual plant parameter values important to typically limiting transients. The results of these studies demonstrate that a margin is expected between performance and the MCPR requirements, and that margins increase as power is reduced to 25% RTP. This trend is expected to continue to the 5% to 15% power range when entry into MODE 2 occurs. When in MODE 2, the intermediate range monitor (IRM) provides rapid scram initiation for any significant power increase transient, which effectively eliminates any MCPR compliance concern. Therefore, at THERMAL POWER levels < 25% RTP, the reactor is operating with substantial margin to the MCPR limits and this LCO is not required.

ACTIONS

A.1

If any MCPR is outside the required limits, an assumption regarding an initial condition of the design basis transient analyses may not be met. Therefore, prompt action should be taken to restore the MCPR(s) to within the required limits such that the plant remains operating within analyzed conditions. The 2 hour Completion Time is normally sufficient to restore the MCPR(s) to within its limits and is acceptable based on the low probability of a transient or DBA occurring simultaneously with the MCPR out of specification.

B.1

If the MCPR cannot be restored to within the required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < 25% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 25% RTP in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

The MCPR is required to be initially calculated within 12 hours after THERMAL POWER is ≥ 25% RTP and then every 24 hours thereafter. It is compared to the specified limits

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1 (continued)

in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 24 hour Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution during normal operation. The 12 hour allowance after THERMAL POWER reaches ≥ 25% RTP is acceptable given the large inherent margin to operating limits at low power levels.

REFERENCES

1. XN-NF-524(A), "Exxon Nuclear Critical Power Methodology for Boiling Water Reactors," Revision 1, November 1983.

2. CENPD-300-P-A, "Reference Safety Report for Boiling Water Reactor Reload Fuel," July 1996.

3. CE-NPSD-802-P, "WNP-2 Cycle 12 Transient Analysis Report," May 1996.

4. CE-NPSD-803-P, "WNP-2 Cycle 12 Reload Report," May 1996.

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

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3 LINEAR HEAT GENERATION RATE (LHGR)

BASES

BACKGROUND

The LHGR is a measure of the heat generation rate of a fuel rod in a fuel assembly at any axial location. Limits on the LHGR are specified to ensure that fuel design limits are not exceeded anywhere in the core during normal operation, including anticipated operational occurrences (AOOs). Exceeding the LHGR limit could potentially result in fuel damage and subsequent release of radioactive materials. Fuel design limits are specified to ensure that fuel system damage, fuel rod failure or inability to cool the fuel does not occur during the anticipated operating conditions identified in References 1 and 2.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the fuel system design are presented in References 1, 2, 3, 4, 5, 6, and 7. The fuel assembly is designed to ensure (in conjunction with the core nuclear and thermal hydraulic design, plant equipment, instrumentation, and protection system) that fuel damage will not result in the release of radioactive materials in excess of the guidelines of 10 CFR, Parts 20, 50, and 100. The mechanisms that could cause fuel damage during operational transients and that are considered in fuel evaluations are:

a. Rupture of the fuel rod cladding caused by strain from the relative expansion of the UO_2 pellet; and

b. Severe overheating of the fuel rod cladding caused by inadequate cooling.

A value of 1% plastic strain of the fuel cladding has been defined as the limit below which fuel damage caused by overstraining of the fuel cladding is not expected to occur (Ref. 8).

Fuel design evaluations have been performed and demonstrate that the 1% fuel cladding plastic strain design limit is not exceeded during continuous operation with LHGRs up to the operating limit specified in the COLR. The analysis also includes allowances for short term transient operation above the operating limit to account for AOOs.

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BASES

APPLICABLE SAFETY ANALYSES (continued)	The LHGR satisfies Criterion 2 of the NRC Policy Statement (Ref. 9).
LCO	The LHGR is a basic assumption in the fuel design analysis. The fuel has been designed to operate at rated core power with sufficient design margin to the LHGR calculated to cause a 1% fuel cladding plastic strain. The operating limit to accomplish this objective is specified in the COLR.
APPLICABILITY	The LHGR limits are derived from fuel design analysis that is limiting at high power level conditions. At core thermal power levels < 25% RTP, the reactor is operating with a substantial margin to the LHGR limits and, therefore, the Specification is only required when the reactor is operating at ≥ 25% RTP.

ACTIONS

A.1

If any LHGR exceeds its required limit, an assumption regarding an initial condition of the fuel design analysis is not met. Therefore, prompt action should be taken to restore the LHGR(s) to within its required limits such that the plant is operating within analyzed conditions. The 2 hour Completion Time is normally sufficient to restore the LHGR(s) to within its limits and is acceptable based on the low probability of a transient or Design Basis Accident occurring simultaneously with the LHGR out of specification.

B.1

If the LHGR cannot be restored to within its required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < 25% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 25% RTP in an orderly manner and without challenging plant systems.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.2.3.1

The LHGRs are required to be initially calculated within 12 hours after THERMAL POWER is ≥ 25% RTP and then every 24 hours thereafter. They are compared with the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 24 hour Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution under normal conditions. The 12 hour allowance after THERMAL POWER ≥ 25% RTP is achieved is acceptable given the large inherent margin to operating limits at lower power levels.

REFERENCES

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

2. CENPD-287-P-A, "Fuel Assembly Mechanical Design Methodology for Boiling Water Reactors," July 1996.

3. XN-NF-81-21(A), "Generic Mechanical Design for Exxon Nuclear Jet Pump BWR Reload Fuel," Revision 1, January 1982.

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

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

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

7. FSAR, Chapter 4.

8. NUREG-0800, Section II A.2(g), Revision 2, July 1981.

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

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 Average Power Range Monitor (APRM) Gain and Setpoint

BASES

BACKGROUND

The OPERABILITY of the APRMs and their setpoints is an initial condition of all safety analyses that assume rod insertion upon reactor scram. Applicable GDCs are GDC 10, "Reactor Design"; GDC 13, "Instrumentation and Control"; GDC 20, "Protection System Functions"; and GDC 29, "Protection against Anticipated Operation Occurrences" (Ref. 1). This LCO is provided to require the APRM gain or APRM flow biased scram setpoints to be adjusted when operating under conditions of excessive power peaking to maintain acceptable margin to the fuel cladding integrity Safety Limit (SL) and the fuel cladding 1% plastic strain limit.

The condition of excessive power peaking is determined by the ratio of the actual power peaking to the limiting power peaking at RTP. This ratio is equal to the ratio of the core limiting MFLPD to the Fraction of RTP (FRTP) where FRTP is the measured THERMAL POWER divided by the RTP. Excessive power peaking exists when:

$$\frac{\text{MFLPD}}{\text{FRTP}} > 1,$$

indicating that MFPLD is not decreasing proportionately to the overall power reduction, or conversely, that power peaking is increasing. To maintain margins similar to those at RTP conditions, the excessive power peaking is compensated by gain adjustment on the APRMs or adjustment of the APRM Flow Biased Simulated Thermal Power—High Function Allowable Value (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," Function 2.b). Either of these adjustments has effectively the same result as maintaining MFLPD less than or equal to FRTP and thus maintains RTP margins for APLHGR, MCPR, and LHGR.

The normally selected APRM Flow Biased Simulated Thermal Power—High Function Allowable Value positions the scram above the upper bound of the normal power/flow operating region that has been considered in the design of the fuel rods. The Allowable Value is flow biased with a slope that approximates the upper flow control line. The normally selected APRM Allowable Value is supported by the analyses presented in References 1 and 2 that concentrate on events

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BASES

BACKGROUND (continued)

initiated from rated conditions. Design experience has shown that minimum deviations occur within expected margins to operating limits (APLHGR, MCPR, and LHGR), at rated conditions for normal power distributions. However, at other than rated conditions, control rod patterns can be established that significantly reduce the margin to thermal limits. Therefore, the APRM Flow Biased Simulated Thermal Power—High Function Allowable Value may be reduced during operation when the combination of THERMAL POWER and MFLPD indicates an excessive power peaking distribution.

The APRM neutron flux signal is also adjusted to more closely follow the fuel cladding heat flux during power transients. The APRM neutron flux signal is a measure of the core thermal power during steady state operation. During power transients, the APRM signal leads the actual core thermal power response because of the fuel thermal time constant. Therefore, on power increase transients, the APRM signal provides a conservatively high measure of core thermal power. By passing the APRM signal through an electronic filter with a time constant less than, but approximately equal to, that of the fuel thermal time constant, an APRM transient response that more closely follows actual fuel cladding heat flux is obtained, while a conservative margin is maintained. The delayed response of the filtered APRM signal allows the APRM Flow Biased Simulated Thermal Power—High Function Allowable Value to be positioned closer to the upper bound of the normal power and flow range, without unnecessarily causing reactor scrams during short duration neutron flux spikes. These spikes can be caused by insignificant transients such as performance of main steam line valve surveillances or momentary flow increases of only several percent.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for the APRM gain or setpoint adjustments are that acceptable margins (to APLHGR, MCPR, and LHGR) be maintained to the fuel cladding integrity SL and the fuel cladding 1% plastic strain limit.

FSAR safety analyses (Ref. 2) concentrate on the rated power condition for which the minimum expected margin to the operating limits (APLHGR, MCPR, and LHGR) occurs. LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," and LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR) limit the initial margins to these operating limits at rated

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BASES

APPLICABLE SAFETY ANALYSES (continued)

conditions so that specified acceptable fuel design limits are met during transients initiated from rated conditions. At initial power levels less than rated levels, the margin degradation of either the APLHGR, the MCPR, or the LHGR during a transient can be greater than at the rated condition event. This greater margin degradation during the transient is primarily offset by the larger initial margin to limits at the lower than rated power levels. However, power distributions can be hypothesized that would result in reduced margins to the pretransient operating limit. When combined with the increased severity of certain transients at other than rated conditions, the SLs could be approached. At substantially reduced power levels, highly peaked power distributions could be obtained that could reduce thermal margins to the minimum levels required for transient events. To prevent or mitigate such situations, either the APRM gain is adjusted upward by the ratio of the core limiting MFLPD to the FRTP, or the APRM Flow Biased Simulated Thermal Power—High Function Allowable Value is required to be reduced by the ratio of FRTP to the core limiting MFLPD. Either of these adjustments effectively counters the increased severity of some events at other than rated conditions by proportionally increasing the APRM gain or proportionally lowering the APRM Flow Biased Simulated Thermal Power—High Function Allowable Value dependent on the increased peaking that may be encountered.

The APRM gain and setpoint satisfy Criteria 2 and 3 of the NRC Policy Statement (Ref. 3).

LCO

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

a. Limiting excess power peaking;

b. Reducing the APRM Flow Biased Simulated Thermal Power—High Function Allowable Value by multiplying the APRM Flow Biased Simulated Thermal Power—High Function Allowable Value by the ratio of FRTP and the core limiting value of MFLPD; or

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

(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.

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

ACTIONS

A.1 (continued)

restore the MFLPD to within its required limit or make acceptable APRM adjustments such that the plant is operating within the assumed margin of the safety analyses.

The 6 hour Completion Time is normally sufficient to restore either the MFLPD to within limits or the APRM gain or Flow Biased Simulated Thermal Power—High Function Allowable Value to within limits and is acceptable based on the low probability of a transient or Design Basis Accident occurring simultaneously with the LCO not met.

B.1

If the APRM gain or Flow Biased Simulated Thermal Power—High Function Allowable Value cannot be restored to within their required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < 25% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 25% RTP in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.4.1 and SR 3.2.4.2

The MFLPD is required to be calculated and compared to FRTP or APRM gain or Flow Biased Simulated Thermal Power—High Function Allowable Value to ensure that the reactor is operating within the assumptions of the safety analysis. These SRs are required only to determine the MFLPD and, assuming MFLPD is greater than FRTP, the appropriate APRM gain or Flow Biased Simulated Thermal Power—High Function Allowable Value, and is not intended to be a CHANNEL FUNCTIONAL TEST for the APRM gain or APRM Flow Biased Simulated Thermal Power—High Function circuitry. The 24 hour Frequency of SR 3.2.4.1 is chosen to coincide with the determination of other thermal limits, specifically those for the APLHGR and LHGR (LCO 3.2.1 and LCO 3.2.3, respectively). The 24 hour Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution during normal operation. The

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.2.4.1 and SR 3.2.4.2 (continued) 12 hour allowance after THERMAL POWER ≥ 25% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels. The 12 hour Frequency of SR 3.2.4.2 is required when MFLPD is greater than FRTP, because more rapid changes in power distribution are typically expected.
REFERENCES	1. 10 CFR 50, Appendix A, GDC 10, GDC 13, GDC 20, and GDC 29. 2. FSAR, Chapters 15 and 15.F. 3. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

BASES

BACKGROUND (continued)

Reference 1. The outputs of the logic channels in a trip system are combined in a one-out-of-two logic so either channel can trip the associated trip system. The tripping of both trip systems will produce a reactor scram. This logic arrangement is referred to as one-out-of-two taken twice logic. Each trip system can be reset by use of a reset switch. If a full scram occurs (both trip systems trip), a relay prevents reset of the trip systems for 10 seconds after the full scram signal is received. This 10 second delay on reset ensures that the scram function will be completed.

Two pilot scram valves are located in the hydraulic control unit (HCU) for each control rod drive (CRD). Each pilot scram valve is solenoid operated, with the solenoids normally energized. The pilot scram valves control the air supply to the scram inlet and outlet valves for the associated CRD. When either pilot scram valve solenoid is energized, air pressure holds the scram valves closed and, therefore, both pilot scram valve solenoids must be de-energized to cause a control rod to scram. The scram valves control the supply and discharge paths for the CRD water during a scram. One of the pilot scram valve solenoids for each CRD is controlled by trip system A, and the other solenoid is controlled by trip system B. Any trip of trip system A in conjunction with any trip in trip system B results in de-energizing both solenoids, air bleeding off, scram valves opening, and control rod scram.

The backup scram valves, which energize on a scram signal to depressurize the scram air header, are also controlled by the RPS. Additionally, the RPS System controls the SDV vent and drain valves such that when both trip systems trip, the SDV vent and drain valves close to isolate the SDV.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The actions of the RPS are assumed in the safety analyses of References 2, 3, 4, 5, 6, and 7. The RPS initiates a reactor scram when monitored parameter values exceed the Allowable Values specified by the setpoint methodology and listed in Table 3.3.1.1-1 to preserve the integrity of the fuel cladding, the RCPB, and the containment by minimizing the energy that must be absorbed following a LOCA. 1C

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

RPS instrumentation satisfies Criterion 3 of the NRC Policy Statement (Ref. 8). Functions not specifically credited in the accident analysis are retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

The OPERABILITY of the RPS is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.1.1-1. Each Function must have a required number of OPERABLE channels per RPS trip system, with their setpoints within the specified Allowable Value, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Each channel must also respond within its assumed response time, where appropriate.

Allowable Values are specified for each RPS Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the actual setpoints do not exceed the Allowable Value between successive 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., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., differential pressure switch) 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 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 OPERABILITY of pilot scram valves and associated solenoids, backup scram valves, and SDV valves, described in the Background section, are not addressed by this LCO.

(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 B 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. 9). 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. 10) to evaluate C C

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

the consequences of control rod withdrawal during startup that are mitigated only by the IRM. This analysis, which assumes that one IRM channel in each trip system is bypassed, demonstrates that the IRMs provide protection against local control rod withdrawal errors and results in peak fuel enthalpy below the 170 cal/gm fuel failure threshold criterion.

The IRMs are also capable of limiting other reactivity excursions during startup, such as cold water injection events, although no credit is specifically assumed.

The IRM System is divided into two groups of IRM channels, with four IRM channels inputting to each trip system. The analysis of Reference 9 assumes that one channel in each trip system is bypassed. Therefore, six channels with three channels in each trip system are required for IRM OPERABILITY to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. This trip is active in each of the 10 ranges of the IRM, which must be selected by the operator to maintain the neutron flux within the monitored level of an IRM range.

The analysis of Reference 9 has adequate conservatism to permit the IRM Allowable Value specified in the Table.

The Intermediate Range Monitor Neutron Flux—High Function must be OPERABLE during MODE 2 when control rods may be withdrawn and the potential for criticality exists. In MODE 5, when a cell with fuel has its control rod withdrawn, the IRMs provide monitoring for and protection against unexpected reactivity excursions. In MODE 1, the APRM System, the RWM and Rod Block Monitor provide protection against control rod withdrawal error events and the IRMs are not required. The IRMs are automatically bypassed when the mode switch is in the run position.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.b. Average Power Range Monitor Flow Biased Simulated Thermal Power—High (continued)

The Average Power Range Monitor Flow Biased Simulated Thermal Power—High Function is required to be OPERABLE in MODE 1 when there is the possibility of generating excessive THERMAL POWER and potentially exceeding the SL applicable to high pressure and core flow conditions (MCPR SL). During MODES 2 and 5, other IRM and APRM Functions provide protection for fuel cladding integrity.

2.c. Average Power Range Monitor Fixed Neutron Flux—High

The APRM channels provide the primary indication of neutron flux within the core and respond almost instantaneously to neutron flux increases. The Average Power Range Monitor Fixed Neutron Flux—High Function is capable of generating a trip signal to prevent fuel damage or excessive Reactor Coolant System (RCS) pressure. For the overpressurization protection analyses of References 2, 3, and 6, the Average Power Range Monitor Fixed Neutron Flux—High Function is assumed to terminate the main steam isolation valve (MSIV) closure event and, along with the safety/relief valves (SRVs), limits the peak reactor pressure vessel (RPV) pressure to less than the ASME Code limits. The control rod drop accident (CRDA) analysis (Ref. 11) takes credit for the Average Power Range Monitor Fixed Neutron Flux—High Function to terminate the CRDA.

The APRM System is divided into two groups of channels with three APRM channels inputting to each trip system. The system is designed to allow one channel in each trip system to be bypassed. Any one APRM channel in a trip system can cause the associated trip system to trip. Four channels of Average Power Range Monitor Fixed Neutron Flux—High with two channels in each trip system arranged in a one-out-of-two logic are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. In addition, to provide adequate coverage of the entire core, at least 14 LPRM inputs are required for each APRM channel, with at least two LPRM inputs from each of the four axial levels at which the LPRMs are located.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.c. Average Power Range Monitor Fixed Neutron Flux—High (continued)

The Allowable Value is based on the Analytical Limit assumed in the CRDA analyses.

The Average Power Range Monitor Fixed Neutron Flux—High Function is required to be OPERABLE in MODE 1 where the potential consequences of the analyzed transients could result in the SLs (e.g., MCPR and RCS pressure) being exceeded. The Average Power Range Monitor Fixed Neutron Flux—High Function is assumed in the CRDA analysis (Ref. 11) that is applicable in MODE 2. However, the Average Power Range Monitor Neutron Flux—High, Setdown Function conservatively bounds the assumed trip and, together with the assumed IRM trips, provides adequate protection. Therefore, the Average Power Monitor Fixed Neutron Flux—High Function is not required in MODE 2. 1C

2.d. Average Power Range Monitor—Inop

This signal provides assurance that a minimum number of APRMs are OPERABLE. Anytime an APRM mode switch is moved to any position other than "Operate," an APRM module is unplugged, or the APRM has too few LPRM inputs (< 14), an inoperative trip signal will be received by the RPS, unless the APRM is bypassed. Since only one APRM in each trip system may be bypassed, only one APRM in each trip system may be inoperable without resulting in an RPS trip signal. This Function was not specifically credited in the accident analysis, but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

Four channels of Average Power Range Monitor—Inop with two channels in each trip system are required to be OPERABLE to ensure that no single failure will preclude a scram from this Function on a valid signal.

There is no Allowable Value for this Function.

This Function is required to be OPERABLE in the MODES where the APRM Functions are required.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

3. Reactor Vessel Steam Dome Pressure—High

An increase in the RPV pressure during reactor operation compresses the steam voids and results in a positive reactivity insertion. This causes the neutron flux and THERMAL POWER transferred to the reactor coolant to increase, which could challenge the integrity of the fuel cladding and the RCPB. No specific safety analysis takes direct credit for this Function. However, the Reactor Vessel Steam Dome Pressure—High Function initiates a scram for transients that result in a pressure increase, counteracting the pressure increase by rapidly reducing core power. For the overpressurization protection analyses of References 2, 3, and 6, the reactor scram (the analyses conservatively assume scram on the Average Power Range Monitor Fixed Neutron Flux—High signal, not the Reactor Vessel Steam Dome Pressure—High signal), along with the SRVs, limits the peak RPV pressure to less than the ASME Section III Code limits.

High reactor pressure signals are initiated from four pressure switches that sense reactor pressure. The Reactor Vessel Steam Dome Pressure—High Allowable Value is chosen to provide a sufficient margin to the ASME Section III Code limits during the event.

Four channels of Reactor Vessel Steam Dome Pressure—High Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. The Function is required to be OPERABLE in MODES 1 and 2 since the RCS is pressurized and the potential for pressure increase exists.

4. Reactor Vessel Water Level—Low, Level 3

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, a reactor scram is initiated at Level 3 to substantially reduce the heat generated in the fuel from fission. The Reactor Vessel Water Level—Low, Level 3 Function is assumed in the analysis of the recirculation line break (Ref. 4). The reactor scram reduces the amount of energy required to be

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4. Reactor Vessel Water Level—Low, Level 3 (continued)

absorbed and, along with the actions of the Emergency Core Cooling Systems (ECCS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Reactor Vessel Water Level—Low, Level 3 signals are initiated from four differential pressure switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

Four channels of Reactor Vessel Water Level—Low, Level 3 Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal.

The Reactor Vessel Water Level—Low, Level 3 Allowable Value is selected to ensure that, for transients involving loss of all normal feedwater flow, initiation of the low pressure ECCS at RPV Water Level 1 will not be required.

The Function is required in MODES 1 and 2 where considerable energy exists in the RCS resulting in the limiting transients and accidents. ECCS initiations at Reactor Vessel Water Level—Low Low, Level 2 and Low Low Low, Level 1 provide sufficient protection for level transients in all other MODES.

5. Main Steam Isolation Valve—Closure

MSIV closure results in loss of the main turbine and the condenser as a heat sink for the Nuclear Steam Supply System and indicates a need to shut down the reactor to reduce heat generation. Therefore, a reactor scram is initiated on a Main Steam Isolation Valve—Closure signal before the MSIVs are completely closed in anticipation of the complete loss of the normal heat sink and subsequent overpressurization transient. However, for the overpressurization protection analyses of References 2, 3, and 6, the Average Power Range Monitor Fixed Neutron Flux—High Function, along with the SRVs, limits the peak RPV pressure to less than the ASME Code limits. That is, the direct scram on position switches for MSIV closure events is not assumed in the overpressurization analysis. Additionally, MSIV closure is

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

7.a, b. Scram Discharge Volume Water Level—High (continued)

and a transmitter and trip unit to each RPS logic channel. The level measurement instrumentation satisfies the recommendations of Reference 12. 1C

The Allowable Value is chosen low enough to ensure that there is sufficient volume in the SDV to accommodate the water from a full scram.

Four channels of each type of Scram Discharge Volume Water Level—High Function, with two channels of each type in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from these Functions on a valid signal. These Functions are required in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn. At all other times, this Function may be bypassed.

8. Turbine Throttle Valve—Closure

Closure of the TTVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated at the start of TTV closure in anticipation of the transients that would result from the closure of these valves. The Turbine Throttle Valve—Closure Function is the primary scram signal for the turbine trip event analyzed in Reference 5. For this event, the reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the End of Cycle Recirculation Pump Trip (EOC-RPT) System, ensures that the MCPR SL is not exceeded.

Turbine Throttle Valve—Closure signals are initiated by valve stem position switches at each throttle valve. Two switches are associated with each throttle valve. One of the two provides input to RPS trip system A; the other, to RPS trip system B. Thus, each RPS trip system receives an input from four Turbine Throttle Valve—Closure channels, each consisting of one valve stem position switch. The

(continued)

BASES

ACTIONS (continued)

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 RPS instrumentation channels provide appropriate compensatory measures for separate, inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable RPS instrumentation channel.

A.1 and A.2

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (Ref. 13) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Functions inoperable channel is in one trip system and the Function still maintains RPS trip capability (refer to Required Actions B.1, B.2, and C.1 Bases.) If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel or the associated trip system must be placed in the tripped condition per Required Actions A.1 and A.2. Placing the inoperable channel in trip (or the associated trip system 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 (or trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Condition D must be entered and its Required Action taken. 1C

B.1 and B.2

Condition B exists when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

Required Actions B.1 and B.2 limit the time the RPS scram logic for any Function would not accommodate single failure in both trip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in Reference 13 for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function will have all required channels either OPERABLE or in trip (or in any combination) in one trip system.

Completing one of these Required Actions restores RPS to an equivalent reliability level as that evaluated in Reference 13, which justified a 12 hour allowable out of service time as presented in Condition A. The trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels, if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision as to which trip system is in the more degraded state should be based on prudent judgment and current plant conditions (i.e., what MODE the plant is in). If this action would result in a scram or recirculation pump trip, it is permissible to place the other trip system or its inoperable channels in trip.

The 6 hour Completion Time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram.

Alternately, if it is not desired to place the inoperable channels (or one trip system) in trip (e.g., as in the case where placing the inoperable channel or associated trip system in trip would result in a scram or RPT), Condition D must be entered and its Required Action taken.

(continued)

BASES

ACTIONS (continued)

C.1

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic and the IRM and APRM Functions, this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip). For Function 5 (Main Steam Isolation Valve—Closure), this would require both trip systems to have each channel associated with the MSIVs in three MSLs (not necessarily the same MSLs for both trip systems), OPERABLE or in trip (or the associated trip system in trip). | C

For Function 8 (Turbine Throttle Valve—Closure), this would require both trip systems to have three channels, each OPERABLE or in trip (or the associated trip system in trip).

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.

D.1

Required Action D.1 directs entry into the appropriate Condition referenced in Table 3.3.1.1-1. The applicable Condition specified in the Table is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed. Each time an inoperable channel has not met any Required Action of Condition A, B, or C, and the associated Completion Time has expired, Condition D will be entered for that channel and provides for transfer to the appropriate subsequent Condition.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

the RPS reliability analysis (Ref. 13) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the RPS will trip when necessary.

SR 3.3.1.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift on 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 3.3.1.1.2

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are calibrated to the reactor power calculated from a heat balance. LCO 3.2.4, "Average Power Range Monitor (APRM) Gain and Setpoint," allows the APRMs to be reading greater than actual THERMAL POWER to compensate for localized power peaking. When this adjustment is made, the requirement for the APRMs to

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.2 (continued)

indicate within 2% RTP of calculated power is modified to require the APRMs to indicate within 2% RTP of calculated MFLPD. The Frequency of once per 7 days is based on minor changes in LPRM sensitivity, which could affect the APRM reading between performances of SR 3.3.1.1.7.

A restriction to satisfying this SR when < 25% RTP is provided that requires the SR to be met only at ≥ 25% RTP because it is difficult to accurately maintain APRM indication of core THERMAL POWER consistent with a heat balance when < 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). At ≥ 25% RTP, the Surveillance is required to have been satisfactorily performed within the last 7 days in accordance with SR 3.0.2. A Note is provided which allows an increase in THERMAL POWER above 25% if the 7 day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after reaching or exceeding 25% RTP. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

SR 3.3.1.1.3

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.

As noted, SR 3.3.1.1.3 is not required to be performed when entering MODE 2 from MODE 1 since testing of the MODE 2 required IRM and APRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This allows entry into MODE 2 if the 7 day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after entering MODE 2 from MODE 1. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

A Frequency of 7 days provides an acceptable level of system average unavailability over the Frequency interval and is based on reliability analysis (Ref. 13). | C

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.4

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended Function. A Frequency of 7 days provides an acceptable level of system average availability over the Frequency and is based on the reliability analysis of Reference 13. (The Manual Scram Functions CHANNEL FUNCTIONAL TEST Frequency was credited in the analysis to extend many automatic scram Functions Frequencies.) 1C

SR 3.3.1.1.5 and SR 3.3.1.1.6

These Surveillances are established to ensure that no gaps in neutron flux indication exist from subcritical to power operation for monitoring core reactivity status.

The overlap between SRMs and IRMs is required to be demonstrated to ensure that reactor power will not be increased into a region without adequate neutron flux indication. This is required prior to withdrawing SRMs from the fully inserted position since indication is being transitioned from the SRMs to the IRMs.

The overlap between IRMs and APRMs is of concern when reducing power into the IRM range. On power increases, the system design will prevent further increases (initiate a rod block) if adequate overlap is not maintained. Overlap between IRMs and APRMs exists when sufficient IRMs and APRMs concurrently have onscale readings such that the transition between MODE 1 and MODE 2 can be made without either APRM downscale rod block, or IRM upscale rod block. Overlap between SRMs and IRMs similarly exists when, prior to withdrawing the SRMs from the fully inserted position, IRMs are above mid-scale on range 1 before SRMs have reached the upscale rod block. The IRM/APRM and SRM/IRM overlaps are also acceptable if a 1/2 decade overlap exists.

As noted, SR 3.3.1.1.6 is only required to be met during entry into MODE 2 from MODE 1. That is, after the overlap requirement has been met and indication has transitioned to the IRMs, maintaining overlap is not required (APRMs may be reading downscale once in MODE 2).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.8 and SR 3.3.1.1.13 (continued)

The 92 day Frequency of SR 3.3.1.1.8 is based on the reliability analysis of Reference 13. The 24 month Frequency of SR 3.3.1.1.13 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. 1C

SR 3.3.1.1.9 and SR 3.3.1.1.10

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.

Note 1 states that neutron detectors are excluded from CHANNEL CALIBRATION because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performing the 7 day calorimetric calibration (SR 3.3.1.1.2) and the 1130 MWD/T LPRM calibration against the TIPs (SR 3.3.1.1.7). A second Note is provided that requires the APRM and IRM SRs to be performed within 12 hours of entering MODE 2 from MODE 1. Testing of the MODE 2 APRM and IRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or moveable links. This Note allows entry into MODE 2 from MODE 1 if the associated Frequency is not met per SR 3.0.2. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR. The Frequency of SR 3.3.1.1.9 is based upon the assumption of a 184 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.1.1.10 is based on the assumption of a 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. 1C

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.14

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional testing of control rods, in LCO 3.1.3, "Control Rod OPERABILITY," and SDV vent and drain valves, in LCO 3.1.8, "Scram Discharge Volume (SDV) Vent and Drain Valves," 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 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 3.3.1.1.15

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. The RPS RESPONSE TIME acceptance criteria are included in Reference 14.

As noted (Note 1), neutron detectors for Function 2 are excluded from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time.

RPS RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS. Note 2 requires STAGGERED TEST BASIS Frequency to be determined based on 4 channels per trip system, in lieu of the 8 channels specified in Table 3.3.1.1-1 for the MSIV Closure Function. This Frequency is based on the logic interrelationships of the various channels required to produce an RPS scram signal. Therefore, staggered testing results in response time verification of these devices every 24 months. The 24 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 time degradation, but not channel failure, are infrequent.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Section 7.2.

2. FSAR, Section 15.2.4.

3. WNP-2 Calculation NE-02-94-66, Revision 0, November 13, 1995.

4. FSAR, Section 6.3.3.

5. FSAR, Chapters 15 and 15.F.

6. CE-NPSD-802-P, "WNP-2 Cycle 12 Transient Analysis Report," May 1996.

7. CE-NPSD-803-P, "WNP-2 Cycle 12 Reload Report," May 1996.

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

9. FSAR, Section 15.4.1.

10. NEDO-23842, "Continuous Control Rod Withdrawal in the Startup Range," April 18, 1978.

11. FSAR, Section 15.F.4.3.

12. Letter, P. Check (NRC) to G. Lainas (NRC), "BWR Scram Discharge System Safety Evaluation," December 1, 1980.

13. NEDO-30851-P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.

14. Licensee Controlled Specifications Manual.

BASES (continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Rod Block Monitor

The RBM is designed to prevent violation of the MCPR SL and the cladding 1% plastic strain fuel design limit that may result from a single control rod withdrawal error (RWE) event. The analytical methods and assumptions used in evaluating the RWE event are summarized in References 3 and 4. A statistical analysis of RWE events was performed to determine the RBM response for both channels for each event. From these responses, the fuel thermal performance as a function of RBM Allowable Value was determined. The Allowable Values are chosen as a function of power level. Based on the specified Allowable Values, operating limits are established.

The RBM Function satisfies Criterion 3 of the NRC Policy Statement (Ref. 5).

Two channels of the RBM are required to be OPERABLE, with their setpoints within the appropriate Allowable Values to ensure that no single instrument failure can preclude a rod block from this Function. The actual setpoints are calibrated consistent with applicable setpoint methodology.

Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Values between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. 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., reactor power), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) 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 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Rod Block Monitor (continued)

The RBM is assumed to mitigate the consequences of an RWE event when operating ≥ 30% RTP and a peripheral control rod is not selected. Below this power level, or if a peripheral control rod is selected, the consequences of an RWE event will not exceed the MCPR SL and, therefore, the RBM is not required to be OPERABLE (Refs. 3 and 4). 1C

2. Rod Worth Minimizer

The RWM enforces the banked position withdrawal sequence (BPWS) to ensure that the initial conditions of the CRDA analysis are not violated. The analytical methods and assumptions used in evaluating the CRDA are summarized in Reference 6. The BPWS requires that control rods be moved in groups, with all control rods assigned to a specific group required to be within specified banked positions. Requirements that the control rod sequence is in compliance with the BPWS are specified in LCO 3.1.6, "Rod Pattern Control." 1C

The RWM Function satisfies Criterion 3 of the NRC Policy Statement (Ref. 5). 1C

Since the RWM is a system designed to act as a backup to operator control of the rod sequences, only one channel of the RWM is available and required to be OPERABLE (Ref. 7). Special circumstances provided for in the Required Action of LCO 3.1.3, "Control Rod OPERABILITY," and LCO 3.1.6 may necessitate bypassing the RWM to allow continued operation with inoperable control rods, or to allow correction of a control rod pattern not in compliance with the BPWS. The RWM may be bypassed as required by these conditions, but then it must be considered inoperable and the Required Actions of this LCO followed.

Compliance with the BPWS, and therefore OPERABILITY of the RWM, is required in MODES 1 and 2 when THERMAL POWER is ≤ 10% RTP. When THERMAL POWER is > 10% RTP, there is no possible control rod configuration that results in a control rod worth that could exceed the 280 cal/gm fuel damage limit during a CRDA (Ref. 6). In MODES 3 and 4, all control rods are required to be inserted into the core; therefore, a CRDA cannot occur. In MODE 5, since only a single control rod 1C

(continued)

BASES

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY

2. Rod Worth Minimizer (continued)

can be withdrawn from a core cell containing fuel assemblies, adequate SDM ensures that the consequences of a CRDA are acceptable, since the reactor will be subcritical.

3. Reactor Mode Switch—Shutdown Position

During MODES 3 and 4, and during MODE 5 when the reactor mode switch is in the shutdown position, the core is assumed to be subcritical; therefore, no positive reactivity insertion events are analyzed. The Reactor Mode Switch—Shutdown Position control rod withdrawal block ensures that the reactor remains subcritical by blocking control rod withdrawal, thereby preserving the assumptions of the safety analysis.

The Reactor Mode Switch—Shutdown Position Function satisfies Criterion 3 of the NRC Policy Statement (Ref. 5). 1

Two channels are required to be OPERABLE to ensure that no single channel failure will preclude a rod block when required. There is no Allowable Value for this Function since the channels are mechanically actuated based solely on reactor mode switch position.

During shutdown conditions (MODE 3, 4, or 5), no positive reactivity insertion events are analyzed because assumptions are that control rod withdrawal blocks are provided to prevent criticality. Therefore, when the reactor mode switch is in the shutdown position, the control rod withdrawal block is required to be OPERABLE. During MODE 5 with the reactor mode switch in the refueling position, the refuel position one-rod-out interlock (LCO 3.9.2 "Refuel Position One-Rod-Out Interlock") provides the required control rod withdrawal blocks.

ACTIONS

A.1

With one RBM channel inoperable, the remaining OPERABLE channel is adequate to perform the control rod block function; however, overall reliability is reduced because a single failure in the remaining OPERABLE channel can result in no control rod block capability for the RBM. For this

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

affect the reactivity of the core and are therefore not required to be inserted. Action must continue until all insertable control rods in core cells containing one or more fuel assemblies are fully inserted.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each Control Rod Block instrumentation Function are found in the SRs column of Table 3.3.2.1-1.

The Surveillances are modified by a second Note to indicate that when an RBM 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 associated Function maintains control rod block capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 8) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that a control rod block will be initiated when necessary. | C

SR 3.3.2.1.1

A CHANNEL FUNCTIONAL TEST is performed for each RBM channel to ensure that the channel will perform the intended function. It includes the Reactor Manual Control Multiplexing System input.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The Frequency of 92 days is based on reliability analyses (Ref. 9). | C

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.1.2 and SR 3.3.2.1.3

A CHANNEL FUNCTIONAL TEST is performed for the RWM to ensure that the entire system will perform the intended function. The CHANNEL FUNCTIONAL TEST for the RWM is performed by attempting to withdraw a control rod not in compliance with the prescribed sequence and verifying a control rod block occurs and, for SR 3.3.2.1.2 only, by attempting to select a control rod not in compliance with the prescribed sequence and verifying a selection error occurs. As noted in the SRs, SR 3.3.2.1.2 is not required to be performed until 1 hour after any control rod is withdrawn at ≤ 10% RTP in MODE 2, and SR 3.3.2.1.3 is not required to be performed until 1 hour after THERMAL POWER is ≤ 10% RTP in MODE 1. This allows entry into MODE 2 (and if entering during a shutdown, concurrent power reduction to ≤ 10% RTP) for SR 3.3.2.1.2, and THERMAL POWER reduction to ≤ 10% RTP in MODE 1 for SR 3.3.2.1.3, to perform the required Surveillances if the 92 day Frequency is not met per SR 3.0.2. The 1 hour allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SRs. The 92 day Frequencies are based on reliability analysis (Ref. 9). 1C

SR 3.3.2.1.4

The RBM is automatically bypassed when power is below a specified value or if a peripheral control rod is selected. The power level is determined from the APRM signals input to each RBM channel. The automatic bypass setpoint must be verified periodically to be < 30% RTP. In addition, it must also be verified that the RBM is not bypassed when a control rod that is not a peripheral control rod is selected (only one non-peripheral control rod is required to be verified). If any bypass setpoint is nonconservative, then the affected RBM channel is considered inoperable. Alternatively, the APRM channel can be placed in the conservative condition (non-bypass). If placed in this condition, the SR is met and the RBM channel is not considered inoperable. As noted, neutron detectors are excluded from the Surveillance because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Neutron detectors are adequately tested in SR 3.3.1.1.2 and SR 3.3.1.1.7. The 92 day Frequency is based on the actual trip setpoint methodology utilized for these channels.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1.7 (continued)

As noted in the SR, the Surveillance is not required to be performed until 1 hour after the reactor mode switch is in the shutdown position, since testing of this interlock with the reactor mode switch in any other position cannot be performed without using jumpers, lifted leads, or movable links. This allows entry into MODES 3 and 4 if the 24 month Frequency is not met per SR 3.0.2. The 1 hour allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SRs.

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.

SR 3.3.2.1.8

The RWM will only enforce the proper control rod sequence if the rod sequence is properly input into the RWM computer. This SR ensures that the proper sequence is loaded into the RWM so that it can perform its intended function. The Surveillance is performed once prior to declaring RWM OPERABLE following loading of sequence into RWM, since this is when rod sequence input errors are possible.

REFERENCES

1. FSAR, Section 7.7.1.8.
2. FSAR, Section 7.7.1.10.
3. FSAR, Section 15.F.4.1.
4. CENPD-300-P-A, "Reference Safety Report for Boiling Water Reactor Reload Fuel," July 1996. C
5. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132). C
6. FSAR, Section 15.F.4.3. C

(continued)

BASES

REFERENCES (continued)

7. NRC SER, "Acceptance of Referencing of Licensing Topical Report NEDE-24011-P-A," "General Electric Standard Application for Reactor Fuel, Revision 8, Amendment 17," December 27, 1987. |C

8. GENE-770-06-1-A, "Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," December 1992. |C

9. NEDC-30851-P-A, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," October 1988. |C

BASES

ACTIONS

C.1 (continued)

sufficient margin to the required limits, and the feedwater and main turbine high water level trip instrumentation is not required to protect fuel integrity during the feedwater controller failure, maximum demand event. The allowed Completion Time of 4 hours is based on operating experience to reduce THERMAL POWER to < 25% RTP from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

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 6 hours provided the associated Function maintains feedwater and main turbine high water level trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 3) assumption that 6 hours is the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the feedwater pump turbines and main turbine will trip when necessary. | C

SR 3.3.2.2.1

Performance of the CHANNEL CHECK once every 24 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.2.4 (continued)

valves and main turbine throttle valves is included as part of this Surveillance and overlaps the LOGIC SYSTEM FUNCTIONAL TEST to provide complete testing of the assumed safety function. Therefore, if a valve is incapable of operating, the associated instrumentation would also be inoperable. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. FSAR, Section 15.F.1.2.

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

3. GENE-770-06-1-A, "Bases for Changes to Surveillance Test Intervals and Allowed Out-Of-Service Times for Selected Instrumentation Technical Specifications," December 1992.

BASES

ACTIONS (continued)

B.1

If a channel has not been restored to OPERABLE status in 30 days, this Required Action specifies initiation of actions in accordance with Specification 5.6.6, which requires a written report to be submitted to the NRC. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. This Required Action is appropriate in lieu of a shutdown requirement since another OPERABLE channel is monitoring the Function, and given the likelihood of plant conditions that would require information provided by this instrumentation. | C

C.1

When one or more Functions have two or more required channels that are inoperable (i.e., two or more channels inoperable in the same Function), all but one channel in the Function should be restored to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with two required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

D.1

This Required Action directs entry into the appropriate Condition referenced in Table 3.3.3.1-1. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met the Required Action of Condition C and the associated Completion Time has expired, Condition D is entered for that channel and provides for transfer to the appropriate subsequent Condition.

(continued)

BASES

ACTIONS (continued)

E.1

For the majority of Functions in Table 3.3.3.1-1, if any Required Action and associated Completion Time of Condition C is not met, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours.

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

F.1

Since alternate means of monitoring primary containment area radiation have been developed and tested, the Required Action is not to shut down the plant but rather to follow the directions of Specification 5.6.6. These alternate means may be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels. | C

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the following SRs apply to each PAM instrumentation Function in Table 3.3.3.1-1.

The Surveillances are modified by a second 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 6 hours, provided the other required channel(s) in the associated Function are OPERABLE. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. The 6 hour testing allowance is acceptable since it does not significantly reduce the probability of properly monitoring post-accident parameters, when necessary.

(continued)

BASES

BACKGROUND (continued)	system trips one of the two drive motor breakers for each recirculation pump and the second trip system trips the other drive motor breaker for each recirculation pump.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The TTV—Closure and the TGV Fast Closure, Trip Oil Pressure—Low Functions are designed to trip the recirculation pumps in the event of a turbine trip or generator load rejection to mitigate the neutron flux, heat flux and pressurization transients, and to increase the margin to the MCPR SL. The analytical methods and assumptions used in evaluating the turbine trip and generator load rejection, as well as other safety analyses that assume EOC-RPT, are summarized in References 2, 3, 4, and 5.

To mitigate pressurization transient effects, the EOC-RPT must trip the recirculation pumps after initiation of initial closure movement of either the TTVs or the TGVs. The combined effects of this trip and a scram reduce fuel bundle power more rapidly than does a scram alone, resulting in an increased margin to the MCPR SL. Alternatively, MCPR limits for an inoperable EOC-RPT as specified in the COLR are sufficient to mitigate pressurization transient effects. The EOC-RPT function is automatically disabled when THERMAL POWER, as sensed by turbine first stage pressure, is < 30% RTP.

EOC-RPT instrumentation satisfies Criterion 3 of the NRC Policy Statement (Ref. 6).

The OPERABILITY of the EOC-RPT is dependent on the OPERABILITY of the individual instrumentation channel Functions. Each Function must have a required number of OPERABLE channels in each trip system, with their setpoints within the specified Allowable Value of SR 3.3.4.1.2. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Channel OPERABILITY also includes the associated EOC-RPT breakers. Each channel (including the associated EOC-RPT breakers) must also respond within its assumed response time.

Allowable Values are specified for each EOC-RPT Function specified in the LCO. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure the setpoints do not exceed the Allowable

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

breakers to be OPERABLE or in trip. Alternatively, Required Action B.2 requires the MCPR limit for inoperable EOC-RPT, as specified in the COLR, to be applied. This also restores the margin to MCPR assumed in the safety analysis.

The 2 hour Completion Time is sufficient for the operator to take corrective action, and takes into account the likelihood of an event requiring actuation of the EOC-RPT instrumentation during this period. It is also consistent with the 2 hour Completion Time provided in LCO 3.2.2, Required Action A.1, since this instrumentation's purpose is to preclude a MCPR violation.

C.1 and C.2

With any Required Action and associated Completion Time not met, THERMAL POWER must be reduced to < 30% RTP within 4 hours. Alternately, the associated recirculation pump may be removed from service since this performs the intended function of the instrumentation. The allowed Completion Time of 4 hours is reasonable, based on operating experience, to reduce THERMAL POWER to < 30% RTP from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

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 6 hours, provided the associated Function maintains EOC-RPT trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 7) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the recirculation pumps will trip when necessary. C

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.1.1

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 reliability analysis (Ref. 7). 1C

SR 3.3.4.1.2

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 3.3.4.1.3

This SR ensures that an EOC-RPT initiated from the TTV–Closure and TGV Fast Closure, Trip Oil Pressure–Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ 30% RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from first stage pressure), the main turbine bypass valves must remain closed during an in-service calibration at THERMAL POWER ≥ 30% RTP to ensure that the calibration is valid. If any bypass channel's setpoint is nonconservative (i.e., the Functions are bypassed at ≥ 30% RTP either due to open main turbine bypass valves or other reasons), the affected TTV–Closure and TGV Fast Closure, Trip Oil Pressure–Low Functions are considered inoperable. Alternatively, the bypass channel

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1.3 (continued)

can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel considered OPERABLE.

The Frequency of 18 months is based on engineering judgement and reliability of the components.

SR 3.3.4.1.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the pump breakers is included as a part of this test, overlapping the LOGIC SYSTEM FUNCTIONAL TEST, to provide complete testing of the associated safety function. Therefore, if a breaker is incapable of operating, the associated instrument channel would also be inoperable.

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

SR 3.3.4.1.5

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. The EOC-RPT SYSTEM RESPONSE TIME acceptance criteria are included in Reference 8. | C

A Note to the Surveillance states that breaker arc suppression time may be assumed from the most recent performance of SR 3.3.4.1.6. This is allowed since the arc suppression time is short and does not appreciably change, due to the design of the breaker opening device and the fact that the breaker is not routinely cycled.

EOC-RPT SYSTEM RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS. Response times cannot be determined at power because operation of final actuated

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1.5 (continued)

devices is required. Therefore, the 24 month Frequency is consistent with the refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components that cause serious response time degradation, but not channel failure, are infrequent occurrences.

SR 3.3.4.1.6

This SR ensures that the RPT breaker arc suppression time is provided to the EOC-RPT SYSTEM RESPONSE TIME test. The 60 month Frequency of the testing is based on the difficulty of performing the test and the reliability of the circuit breakers.

REFERENCES

1. FSAR, Appendix H.
2. FSAR, Section 5.2.2.
3. FSAR, Sections 15.2.2, 15.2.3, 15.2.5, and 15.2.6.
4. FSAR, Section 15.F.2.1.
5. CENPD-300-P-A, "Reference Safety Report for Boiling Water Reactor Reload Fuel," July 1996.
6. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
7. GENE-770-06-1-A, "Bases for Changes To Surveillance Test Intervals And Allowed Out-Of-Service Times For Selected Instrumentation Technical Specifications," December 1992.
8. Licensee Controlled Specifications Manual.

B 3.3 INSTRUMENTATION

B 3.3.4.2 Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation

BASES

BACKGROUND

The ATWS-RPT System initiates a recirculation pump trip, adding negative reactivity, following events in which a scram does not, but should occur, to lessen the effects of an ATWS event. Tripping the recirculation pumps adds negative reactivity from the increase in steam voiding in the core area as core flow decreases. When Reactor Vessel Water Level — Low Low, Level 2 or Reactor Vessel Steam Dome Pressure — High setpoint is reached, the recirculation pump motor breakers trip.

The ATWS-RPT System (Ref. 1) includes sensors, relays, bypass capability, circuit breakers, and switches that are necessary to cause initiation of a recirculation pump trip. The channels include electronic equipment (e.g., trip relays) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel outputs an ATWS-RPT signal to the trip logic.

The ATWS-RPT consists of two independent trip systems, with two channels of Reactor Vessel Steam Dome Pressure — High and two channels of Reactor Vessel Water Level — Low Low, Level 2, in each trip system. Each ATWS-RPT trip system is a two-out-of-two logic for each Function. Thus, either two Reactor Water Level — Low Low, Level 2 or two Reactor Vessel Steam Dome Pressure — High signals are needed to trip a trip system. The outputs of the channels in a trip system are combined in a logic so that one trip system trips one recirculation pump (by tripping one of the respective drive motor breakers) while the other trip system trips the other recirculation pump. C

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The ATWS-RPT is not assumed in the safety analysis. The ATWS-RPT initiates an RPT to aid in preserving the integrity of the fuel cladding following events in which scram does not, but should, occur. Based on its contribution to the reduction of overall plant risk, however, the instrumentation meets Criterion 4 of the NRC Policy Statement (Ref. 2).

(continued)

BASES

ACTIONS (continued)

A.1 and A.2

With one or more channels inoperable, but with ATWS-RPT trip capability for each Function maintained (refer to Required Action B.1 and C.1 Bases), the ATWS-RPT System is capable of performing the intended function for one of the recirculation pumps. However, the reliability and redundancy of the ATWS-RPT instrumentation is reduced, such that a single failure in the remaining trip system could result in the inability of the ATWS-RPT System to perform the intended function for both of the recirculation pumps. Therefore, only a limited time is allowed to restore the inoperable channels to OPERABLE status. Because of the diversity of sensors available to provide trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of ATWS-RPT, 7 days is provided to restore the inoperable channel (Required Action A.1). Alternately, the inoperable channel may be placed in trip (Required Action A.2), since this would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. As noted, placing the channel in trip with no further restrictions is not allowed if the inoperable channel is the result of an inoperable breaker, since this may not adequately compensate for the inoperable breaker (e.g., the breaker may be inoperable such that it will not open). If it is not desirable to place the channel in trip (e.g., as in the case where placing the inoperable channel would result in an RPT), or if the inoperable channel is the result of an inoperable breaker, Condition D must be entered and its Required Actions taken.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in the Function not maintaining ATWS-RPT trip capability. A Function is considered to be maintaining ATWS-RPT trip capability when sufficient channels are OPERABLE or in trip such that the ATWS-RPT System will generate a trip signal from the given Function on a valid signal, and one recirculation pump can be tripped. This requires two channels of the Function in

(continued)

BASES

ACTIONS

B.1 (continued)

the same trip system to each be OPERABLE or in trip, and the two breakers (one drive motor breaker and one LFMG output breaker) to be OPERABLE or in trip.

The 72 hour Completion Time is sufficient for the operator to take corrective action (e.g., restoration or tripping of channels) and takes into account the likelihood of an event requiring actuation of the ATWS-RPT instrumentation during this period and the fact that one Function is still maintaining ATWS-RPT trip capability.

C.1

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within both Functions result in both Functions not maintaining ATWS-RPT trip capability. The description of a Function maintaining ATWS-RPT trip capability is discussed in the Bases for Required Action B.1, above.

The 1 hour Completion Time is sufficient for the operator to take corrective action and takes into account the likelihood of an event requiring actuation of the ATWS-RPT instrumentation during this period.

D.1 and D.2

With any Required Action and associated Completion Time not met, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 2 within 6 hours (Required Action D.2). Alternately, the associated recirculation pump may be removed from service since this performs the intended Function of the instrumentation (Required Action D.1). The allowed Completion Time of 6 hours is reasonable, based on operating experience, both to reach MODE 2 from full power conditions and to remove a recirculation pump from service in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

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 6 hours provided the associated Function maintains ATWS-RPT trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 3) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the recirculation pumps will trip when necessary.

SR 3.3.4.2.1

Performance of the CHANNEL CHECK once every 12 hours ensures that gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the 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 that 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 required channels of this LCO.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.2.2

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 analysis of Reference 3.

SR 3.3.4.2.3

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

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

SR 3.3.4.2.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the pump breakers, included as part of this Surveillance, overlaps the LOGIC SYSTEM FUNCTIONAL TEST to provide complete testing of the assumed safety function. Therefore, if a breaker is incapable of operating, the associated instrument channel(s) would be inoperable.

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

(continued)

BASES

BACKGROUND (continued)

Diesel Generators

The Division 1, 2, and 3 DGs may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level—Low Low Low, Level 1 or Drywell Pressure—High for DGs 1 and 2, and Reactor Vessel Water Level—Low Low, Level 2 or Drywell Pressure—High for DG 3. The DGs are also initiated upon loss of voltage signals. (Refer to Bases for LCO 3.3.8.1, "Loss of Power (LOP) Instrumentation," for a discussion of these signals.) Reactor vessel water level is monitored by two redundant differential pressure switches and drywell pressure is monitored by two redundant pressure switches per DG, which are, in turn, connected to two level switch and two pressure switch contacts, respectively. The outputs of the four divisionalized switches (two switches from each of the two variables) are connected to relays whose contacts are connected to a one-out-of-two taken twice logic. The DGs receive their initiation signals from the associated Divisions' ECCS logic (i.e., DG 1 receives an initiation signal from Division 1 ECCS (LPCS and LPCI A); DG 2 receives an initiation signal from Division 2 ECCS (LPCI B and LPCI C); and DG 3 receives an initiation signal from Division 3 ECCS (HPCS)). The DGs can also be started manually from the control room and locally in the associated DG room. The DG initiation signal is a sealed in signal and must be manually reset. The DG initiation logic is reset by resetting the associated ECCS initiation logic. Upon receipt of an ECCS initiation signal, each DG is automatically started, is ready to load in approximately 15 seconds, and will run in standby conditions (rated voltage and speed, with the DG output breaker open). The DGs will only energize their respective Engineered Safety Feature (ESF) buses if a loss of offsite power occurs (Refer to Bases for LCO 3.3.8.1).

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The actions of the ECCS are explicitly assumed in the safety analyses of References 1, 2, 3, 4, 5, and 6. The ECCS is initiated to preserve the integrity of the fuel cladding by limiting the post LOCA peak cladding temperature to less than the 10 CFR 50.46 limits. 1C

ECCS instrumentation satisfies Criterion 3 of the NRC Policy Statement (Ref. 7). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion. 1A

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The OPERABILITY of the ECCS instrumentation is dependent and upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.5.1-1. Each Function must have a required number of OPERABLE channels, with their setpoints within the specified Allowable Values, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Each ECCS injection/spray subsystem must also respond within its assumed response time. Table 3.3.5.1-1, footnote (b), is added to show that certain ECCS instrumentation Functions are also required to be OPERABLE to perform DG initiation.

Allowable Values are specified for each ECCS Function specified in the Table. 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 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., reactor vessel water level), 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 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. Some functions have both an upper and lower analytic limit that must be evaluated. The Allowable Values and the trip setpoints are derived from both an upper and lower analytic limit using the methodology described above. Due to the upper and lower analytic limits, Allowable Values of these Functions appear to incorporate a range. However, the upper and lower Allowable Values are unique, with each Allowable Value associated with one unique analytic limit and trip setpoint.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In general, the individual Functions are required to be OPERABLE in the MODES or other specified conditions that may require ECCS (or DG) initiation to mitigate the consequences of a design basis accident or transient. To ensure reliable ECCS and DG function, a combination of Functions is required to provide primary and secondary initiation signals.

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

Low Pressure Core Spray and Low Pressure Coolant Injection Systems

1.a, 2.a. Reactor Vessel Water Level—Low Low Low, Level 1

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. The low pressure ECCS and associated DGs are initiated at Level 1 to ensure that core spray and flooding functions are available to prevent or minimize fuel damage. The Reactor Vessel Water Level—Low Low Low, Level 1 is one of the Functions assumed to be OPERABLE and capable of initiating the ECCS during the transients analyzed in References 1 and 3. In addition, the Reactor Vessel Water Level—Low Low Low, Level 1 Function is directly assumed in the analysis of the recirculation line break (Refs. 2, 4, 5, and 6). The core cooling function of the ECCS, along with the scram action of the Reactor Protection System (RPS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. | C

Reactor Vessel Water Level—Low Low Low, Level 1 signals are initiated from four differential pressure switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. The Reactor Vessel Water Level—Low Low Low, Level 1 Allowable Value is chosen to allow time for the low pressure core flooding systems to activate and provide adequate cooling.

Two channels of Reactor Vessel Water Level—Low Low Low, Level 1 Function per associated Division are only required to be OPERABLE when the associated ECCS or DG is required to

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.a, 2.a. Reactor Vessel Water Level—Low Low Low, Level 1 (continued)

be OPERABLE, to ensure that no single instrument failure can preclude ECCS initiation. (Two channels input to LPCS, LPCI A, and DG 1, while the other two channels input to LPCI B, LPCI C, and DG 2.) Refer to LCO 3.5.1 and LCO 3.5.2, "ECCS—Shutdown," for Applicability Bases for the low pressure ECCS subsystems; LCO 3.8.1, "AC Sources—Operating"; and LCO 3.8.2, "AC Sources—Shutdown," for Applicability Bases for the DGs.

1.b, 2.b. Drywell Pressure—High

High pressure in the drywell could indicate a break in the reactor coolant pressure boundary (RCPB). The low pressure ECCS and associated DGs are initiated upon receipt of the Drywell Pressure—High Function in order to minimize the possibility of fuel damage. However, no credit is taken for the Drywell Pressure—High Function to start the low pressure ECCS in any design basis accident or transient analyses. It is retained for overall redundancy and diversity of the low pressure ECCS function as required by the NRC in the plant licensing basis. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

High drywell pressure signals are initiated from four pressure switches that sense drywell pressure. The Allowable Value was selected to be as low as possible and be indicative of a LOCA inside primary containment. Negative barometric fluctuations are accounted for in the Allowable Value.

The Drywell Pressure—High Function is required to be OPERABLE when the associated ECCS and DGs are required to be OPERABLE in conjunction with times when the primary containment is required to be OPERABLE. Thus, four channels of the LPCS and LPCI Drywell Pressure—High Function are required to be OPERABLE in MODES 1, 2, and 3 to ensure that no single instrument failure can preclude ECCS initiation. (Two channels input to LPCS, LPCI A, and DG 1, while the other two channels input to LPCI B, LPCI C, and DG 2.) In MODES 4 and 5, the Drywell Pressure—High Function is not required since there is insufficient energy in the reactor

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.b, 2.b. Drywell Pressure—High (continued)

to pressurize the primary containment to Drywell Pressure—High setpoint. Refer to LCO 3.5.1 for Applicability Bases for the low pressure ECCS subsystems and to LCO 3.8.1 for Applicability Bases for the DGs.

1.c, 1.d, 1.e, 2.c, 2.d, 2.e. LPCS and LPCI Pumps A, B, and C Start—LOCA Time Delay Relay and LPCI Pumps A and B Start—LOCA/LOOP Time Delay Relay

The purpose of these time delays is to stagger the start of the ECCS pumps that are in each of Divisions 1 and 2, thus limiting the starting transients on the 4.16 kV emergency buses. The LOCA Time Delay Relay Function is only necessary when the power is being supplied from the TR-S transformer, and the LOCA/LOOP Time Delay Relay Function is only necessary when power is being supplied from the standby power sources (DG). However, since the LOCA/LOOP time delay does not degrade ECCS operation, it remains in the pump start logic at all times. The Pump Start—LOCA and LOCA/LOOP Time Delay Relays are assumed to be OPERABLE in the accident and transient analyses requiring ECCS initiation. That is, the analysis assumes that the pumps will initiate when required and excess loading will not cause failure of the power sources.

There are four Pump Start—LOCA Time Delay Relays, one in each of the low pressure ECCS pump start logic circuits, and two Pump Start—LOCA/LOOP Time Delay Relays, one in each of the RHR "A" and RHR "B" pump start logic circuits. While each time delay relay is dedicated to a single pump start logic, a single failure of a Pump Start—LOCA or LOCA/LOOP Time Delay Relay could result in the failure of the two low pressure ECCS pumps, powered from the same ESF bus, to perform their intended function within the assumed ECCS RESPONSE TIMES (e.g., as in the case where both ECCS pumps on one ESF bus start simultaneously due to an inoperable time delay relay). This still leaves two of the four low pressure ECCS pumps OPERABLE; thus, the single failure criterion is met (i.e., loss of one instrument does not preclude ECCS initiation). The Allowable Values for the Pump Start—LOCA and LOCA/LOOP Time Delay Relays are chosen to be long enough so that most of the starting transient of

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.c, 1.d, 1.e, 2.c, 2.d, 2.e. LPCS and LPCI Pumps A, B, and C Start—LOCA Time Delay Relay and LPCI Pumps A and B Start—LOCA/LOOP Time Delay Relay (continued)

the first pump is complete before starting the second pump on the same 4.16 kV emergency bus and short enough so that ECCS operation is not degraded.

Each channel of Pump Start—LOCA and LOCA/LOOP Time Delay Relay Function is only required to be OPERABLE when the associated LPCI subsystem is required to be OPERABLE. Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the LPCI subsystems.

1.f, 2.f. Reactor Vessel Pressure—Low (Injection Permissive)

Low reactor vessel pressure signals are used as permissives for the low pressure ECCS subsystems. This ensures that, prior to opening the injection valves of the low pressure ECCS subsystems, the reactor pressure has fallen to a value below these subsystems' maximum design pressure. The Reactor Vessel Pressure—Low is one of the Functions assumed to be OPERABLE and capable of permitting initiation of the ECCS during the transients analyzed in References 1 and 3. In addition, the Reactor Vessel Pressure—Low Function is directly assumed in the analysis of the recirculation line break (Refs. 2, 4, 5, and 6). The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. |C

The Reactor Vessel Pressure—Low signals are initiated from four pressure switches that sense the reactor dome pressure (one pressure switch for each low pressure ECCS injection valve).

The Allowable Value is low enough to prevent overpressurizing the equipment in the low pressure ECCS, but high enough to ensure that the ECCS injection prevents the fuel peak cladding temperature from exceeding the limits of 10 CFR 50.46.

Each channel of Reactor Vessel Pressure—Low Function (one per valve) is only required to be OPERABLE when the associated ECCS is required to be OPERABLE to ensure that no

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.f, 2.f. Reactor Vessel Pressure—Low (Injection Permissive) (continued)

single instrument failure can preclude ECCS initiation. Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the low pressure ECCS subsystems.

1.g, 1.h, 2.g. LPCS and LPCI Pump Discharge Flow—Low (Minimum Flow)

The minimum flow instruments are provided to protect the associated low pressure ECCS pump from overheating when the pump is operating and the associated injection valve is not sufficiently open. The minimum flow line valve is opened when low flow is sensed, and the valve is automatically closed when the flow rate is adequate to protect the pump. The LPCI and LPCS Pump Discharge Flow—Low Functions are assumed to be OPERABLE and capable of closing the minimum flow valves to ensure that the low pressure ECCS flows assumed during the transients and accidents analyzed in References 1, 2, 3, 4, 5, and 6 are met. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. 1C

One flow indicating switch per ECCS pump is used to detect the associated subsystem's flow rate. The logic is arranged such that each indicating switch causes its associated minimum flow valve to open when flow is low with the pump running. The logic will close the minimum flow valve once the closure setpoint is exceeded. The LPCI minimum flow valves are time delayed such that the valves will not open for 8 seconds after the switches detect low flow. The time delay is provided to limit reactor vessel inventory loss during the startup of the RHR shutdown cooling mode. The Pump Discharge Flow—Low Allowable Values are high enough to ensure that the pump flow rate is sufficient to protect the pump, yet low enough to ensure that the closure of the minimum flow valve is initiated to allow full flow into the core.

Each channel of Pump Discharge Flow—Low Function (one LPCS channel and three LPCI channels) is only required to be OPERABLE when the associated ECCS is required to be OPERABLE, to ensure that no single instrument failure can

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.g, 1.h, 2.g. LPCS and LPCI Pump Discharge Flow—Low (Minimum Flow) (continued)

preclude the ECCS function. Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the low pressure ECCS subsystems.

1.i, 2.h. Manual Initiation

The Manual Initiation switch and push button channels introduce signals into the appropriate ECCS logic to provide manual initiation capability and are redundant to the automatic protective instrumentation. There is one switch and push button (with two channels per switch and push button) for each of the two Divisions of low pressure ECCS (i.e., Division 1 ECCS, LPCS and LPCI A; Division 2 ECCS, LPCI B and LPCI C).

The Manual Initiation Function is not assumed in any accident or transient analyses in the FSAR. However, the Function is retained for overall redundancy and diversity of the low pressure ECCS function as required by the NRC in the plant licensing basis.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the switch and push buttons. Each channel of the Manual Initiation Function (two channels per Division) is only required to be OPERABLE when the associated ECCS is required to be OPERABLE. Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the low pressure ECCS subsystems.

High Pressure Core Spray System

3.a. Reactor Vessel Water Level—Low Low, Level 2

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, the HPCS System and associated DG is initiated at Level 2 to maintain level above the top of the active fuel. The Reactor Vessel Water Level—Low Low, Level 2 is one of the Functions assumed to be OPERABLE and capable of initiating HPCS during the transients analyzed in References 1 and 3. The Reactor

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.a. Reactor Vessel Water Level — Low Low, Level 2 (continued)

Vessel Water Level — Low Low, Level 2 Function associated with HPCS is directly assumed in the analysis of the recirculation line break (Refs. 2, 4, 5, and 6). The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Reactor Vessel Water Level — Low Low, Level 2 signals are initiated from four differential pressure switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

The Reactor Vessel Water Level — Low Low, Level 2 Allowable Value is chosen such that for complete loss of feedwater flow, the Reactor Core Isolation Cooling (RCIC) System flow with HPCS assumed to fail will be sufficient to avoid initiation of low pressure ECCS at Reactor Vessel Water Level — Low Low Low, Level 1.

Four channels of Reactor Vessel Water Level — Low Low, Level 2 Function are only required to be OPERABLE when HPCS is required to be OPERABLE to ensure that no single instrument failure can preclude HPCS initiation. Refer to LCO 3.5.1 and LCO 3.5.2 for HPCS Applicability Bases.

3.b. Drywell Pressure — High

High pressure in the drywell could indicate a break in the RCPB. The HPCS System and associated DG are initiated upon receipt of the Drywell Pressure — High Function in order to minimize the possibility of fuel damage. However, no credit is taken for the Drywell Pressure — High Function to start the HPCS System in any DBA or transient analyses; that is, HPCS is assumed to be initiated on Reactor Water Level — Low Low, Level 2. It is retained for overall redundancy and diversity of the HPCS function as required by the NRC in the plant licensing basis. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.b. Drywell Pressure–High (continued)

Drywell Pressure–High signals are initiated from four pressure switches that sense drywell pressure. The Allowable Value was selected to be as low as possible and be indicative of a LOCA inside primary containment.

The Drywell Pressure–High Function is required to be OPERABLE when HPCS is required to be OPERABLE in conjunction with times when the primary containment is required to be OPERABLE. Thus, four channels of the HPCS Drywell Pressure–High Function are required to be OPERABLE in MODES 1, 2, and 3, to ensure that no single instrument failure can preclude ECCS initiation. In MODES 4 and 5, the Drywell Pressure–High Function is not required since there is insufficient energy in the reactor to pressurize the drywell to the Drywell Pressure–High Function's setpoint. Refer to LCO 3.5.1 for the Applicability Bases for the HPCS System.

3.c Reactor Vessel Water Level–High, Level 8

High RPV water level indicates that sufficient cooling water inventory exists in the reactor vessel such that there is no danger to the fuel. Therefore, the Level 8 signal is used to close the HPCS injection valve to prevent overflow into the main steam lines (MSLs). The Reactor Vessel Water Level–High, Level 8 Function is not assumed in the accident and transient analyses. It was retained since it is a potentially significant contributor to risk, thus it meets Criterion 4 of the NRC Policy Statement (Ref. 7). 1C

Reactor Vessel Water Level–High, Level 8 signals for HPCS are initiated from two differential pressure switches from the narrow range water level measurement instrumentation. The Reactor Vessel Water Level–High, Level 8 Allowable Value is chosen to isolate flow from the HPCS System prior to water overflowing into the MSLs.

Two channels of Reactor Vessel Water Level–High, Level 8 Function are only required to be OPERABLE when HPCS is required to be OPERABLE to ensure that no single instrument failure can preclude HPCS initiation. Refer to LCO 3.5.1 and LCO 3.5.2 for HPCS Applicability Bases.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3.d. Condensate Storage Tank Level—Low

Low level in the CST indicates the unavailability of an adequate supply of makeup water from this normal source. Normally the suction valves between HPCS and the CST are open and, upon receiving a HPCS initiation signal, water for HPCS injection would be taken from the CST. However, if the water level in the CST falls below a preselected level, first the suppression pool suction valve automatically opens, and then the CST suction valve automatically closes. This ensures that an adequate supply of makeup water is available to the HPCS pump. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valve must be open before the CST suction valve automatically closes. The Function is implicitly assumed in the accident and transient analyses (which take credit for HPCS) since the analyses assume that the HPCS suction source is the suppression pool.

Condensate Storage Tank Level—Low signals are initiated from two level switches mounted on a Seismic Category I standpipe in the reactor building (the two switches mounted on the CST cannot be credited since they are not Seismic Category I). The Condensate Storage Tank Level—Low Function Allowable Value is high enough to ensure adequate pump suction head while water is being taken from the CST.

Two channels of the Condensate Storage Tank Level—Low Function are only required to be OPERABLE when HPCS is required to be OPERABLE to ensure that no single instrument failure can preclude HPCS swap to suppression pool source. Thus, the Function is required to be OPERABLE in MODES 1, 2, and 3. In MODES 4 and 5, the Function is required to be OPERABLE only when HPCS is required to be OPERABLE to fulfill the requirements of LCO 3.5.2, HPCS is aligned to the CST, and the CST water level is not within the limits of SR 3.5.2.2. With CST water level within limits, a sufficient supply of water exists for injection to minimize the consequences of a vessel draindown event. Refer to LCO 3.5.1 and LCO 3.5.2 for HPCS Applicability Bases.

3.e. Suppression Pool Water Level—High

Excessively high suppression pool water could result in the loads on the suppression pool exceeding design values should there be a blowdown of the reactor vessel pressure through

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.e. Suppression Pool Water Level—High (continued)

the SRVs. Therefore, signals indicating high suppression pool water level are used to transfer the suction source of HPCS from the CST to the suppression pool to eliminate the possibility of HPCS continuing to provide additional water from a source outside containment. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valve must be open before the CST suction valve automatically closes. This Function is implicitly assumed in the accident and transient analyses (which take credit for HPCS) since the analyses assume that the HPCS suction source is the suppression pool.

Suppression Pool Water Level—High signals are initiated from two level switches. The Allowable Value for the Suppression Pool Water Level—High Function is chosen to ensure that HPCS will be aligned for suction from the suppression pool before the water level reaches the point at which suppression pool design loads would be exceeded.

Two channels of Suppression Pool Water Level—High Function are only required to be OPERABLE in MODES 1, 2, and 3 when HPCS is required to be OPERABLE to ensure that no single instrument failure can preclude HPCS swap to suppression pool source. In MODES 4 and 5, the Function is not required to be OPERABLE since the reactor is depressurized and vessel blowdown, which could cause the design values of the containment to be exceeded, cannot occur. Refer to LCO 3.5.1 for HPCS Applicability Bases.

3.f. HPCS System Flow Rate—Low (Minimum Flow)

The minimum flow instrument is provided to protect the HPCS pump from overheating when the pump is operating and the associated injection valve is not sufficiently open. The minimum flow line valve is opened when low flow is sensed, and the valve is automatically closed when the flow rate is adequate to protect the pump. The HPCS System Flow Rate—Low Function is assumed to be OPERABLE and capable of closing the minimum flow valve to ensure that the ECCS flow assumed during the transients and accidents analyzed in References 1, 2, 3, 4, 5, and 6 are met. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. 1C

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.f. HPCS System Flow Rate—Low (Minimum Flow) (continued)

One flow switch is used to detect the HPCS Systems flow rate. The logic is arranged such that the flow switch causes the minimum flow valve to open when flow is low with the pump running. The logic will close the minimum flow valve once the closure setpoint is exceeded.

The HPCS System Flow Rate—Low Allowable Value is high enough to ensure that pump flow rate is sufficient to protect the pump, yet low enough to ensure that the closure of the minimum flow valve is initiated to allow full flow into the core.

One channel of HPCS System Flow Rate—Low Function is required to be OPERABLE when the HPCS is required to be OPERABLE. Refer to LCO 3.5.1 and LCO 3.5.2 for HPCS Applicability Bases.

3.g. Manual Initiation

The Manual Initiation switch and push button channels introduce a signal into the HPCS logic to provide manual initiation capability and is redundant to the automatic protective instrumentation. There is one switch and push button (with two channels) for the HPCS System.

The Manual Initiation Function is not assumed in any accident or transient analyses in the FSAR. However, the Function is retained for overall redundancy and diversity of the HPCS function as required by the NRC in the plant licensing basis.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the switch and push button. Two channels of the Manual Initiation Function are only required to be OPERABLE when the HPCS System are required to be OPERABLE. Refer to LCO 3.5.1 and LCO 3.5.2 for HPCS Applicability Bases.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Automatic Depressurization System

4.a, 5.a. Reactor Vessel Water Level — Low Low Low, Level 1

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, ADS receives one of the signals necessary for initiation from this Function. The Reactor Vessel Water Level — Low Low Low, Level 1 is one of the Functions assumed to be OPERABLE and capable of initiating the ADS during the accidents analyzed in References 2, 4, 5, and 6. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. 1C

The Reactor Vessel Water Level — Low Low Low, Level 1 signals are initiated from four differential pressure switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. The Reactor Vessel Water Level — Low Low Low, Level 1 Allowable Value is chosen to allow time for the low pressure core spray and flooding systems to initiate and provide adequate cooling.

Four channels of Reactor Vessel Water Level — Low Low Low, Level 1 Function are only required to be OPERABLE when ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. (Two channels input to ADS trip system A while the other two channels input to ADS trip system B). Refer to LCO 3.5.1 for ADS Applicability Bases.

4.b, 5.b. ADS Initiation Timer

The purpose of the ADS Initiation Timer is to delay depressurization of the reactor vessel to allow the HPCS System time to maintain reactor vessel water level. Since the rapid depressurization caused by ADS operation is one of the most severe transients on the reactor vessel, its occurrence should be limited. By delaying initiation of the ADS Function, the operator is given the chance to monitor the success or failure of the HPCS System to maintain water level, and then to decide whether or not to allow ADS to initiate, to delay initiation further by recycling the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.b, 5.b. ADS Initiation Timer (continued)

timer, or to inhibit initiation permanently. The ADS Initiation Timer Function is assumed to be OPERABLE for the accident analyses of References 2, 4, 5, and 6 that require ECCS initiation and assume failure of the HPCS System.

There are two ADS Initiation Timer relays, one in each of the two ADS trip systems. The Allowable Value for the ADS Initiation Timer is chosen to be short enough so that there is still time after depressurization for the low pressure ECCS subsystems to provide adequate core cooling.

Two channels of the ADS Initiation Timer Function are only required to be OPERABLE when the ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. (One channel inputs to ADS trip system A while the other channel inputs to ADS trip system B.) Refer to LCO 3.5.1 for ADS Applicability Bases.

4.c, 5.c. Reactor Vessel Water Level – Low, Level 3 (Permissive)

The Reactor Vessel Water Level – Low, Level 3 Function is used by the ADS only as a confirmatory low water level signal. ADS receives one of the signals necessary for initiation from Reactor Vessel Water Level – Low Low Low, Level 1 signals. In order to prevent spurious initiation of the ADS due to spurious Level 1 signals, a Level 3 signal must also be received before ADS initiation commences.

Reactor Vessel Water Level – Low, Level 3 signals are initiated from two differential pressure switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. The Allowable Value for Reactor Vessel Water Level – Low, Level 3 is selected at the RPS Level 3 scram Allowable Value for convenience. Refer to LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," for Bases discussion of this Function.

Two channels of Reactor Vessel Water Level – Low, Level 3 Function are only required to be OPERABLE when the ADS is required to be OPERABLE to ensure that no single instrument

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.c, 5.c. Reactor Vessel Water Level—Low, Level 3 (Permissive) (continued)

failure can preclude ADS initiation. (One channel inputs to ADS trip system A while the other channel inputs to ADS trip system B.) Refer to LCO 3.5.1 for ADS Applicability Bases.

4.d, 4.e, 5.d. LPCS and LPCI Pump Discharge Pressure—High

The Pump Discharge Pressure—High signals (indicating that the pump is running) from the LPCS and LPCI pumps are used as permissives for ADS initiation, indicating that there is a source of low pressure cooling water available once the ADS has depressurized the vessel. Pump Discharge Pressure—High is one of the Functions assumed to be OPERABLE and capable of permitting ADS initiation during the events analyzed in References 2, 4, 5, and 6 with an assumed HPCS failure. For these events, the ADS depressurizes the reactor vessel so that the low pressure ECCS can perform the core cooling functions. This core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. 1C

Pump discharge pressure signals are initiated from eight pressure switches, two on the discharge side of each of the four low pressure ECCS pumps. In order to generate an ADS permissive in one trip system, it is necessary that only one pump (both channels for the pump) indicate the high discharge pressure condition. The Pump Discharge Pressure—High Allowable Value is less than the pump discharge pressure when the pump is operating in a full flow mode, and high enough to avoid any condition that results in a discharge pressure permissive when the LPCS and LPCI pumps are aligned for injection and the pumps are not running. The actual operating point of this Function is not assumed in any transient or accident analysis.

Eight channels of LPCS and LPCI Pump Discharge Pressure—High Function (two LPCS and two LPCI A channels input to ADS trip system A, while two LPCI B and two LPCI C channels input to ADS trip system B) are only required to be OPERABLE when the ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. Refer to LCO 3.5.1 for ADS Applicability Bases.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

4.f, 5.e. Accumulator Backup Compressed Gas System Pressure—Low

The purpose of the Accumulator Backup Compressed Gas System Pressure—Low Function is to ensure that a safety related supply of air is available to the ADS valves during post LOCA conditions. The normal air supply to the ADS valves is non-safety related and may not be available following a LOCA. If the normal air supply pressure is low, the Accumulator Backup Compressed Gas System Pressure—Low Function will automatically align the Accumulator Backup Compressed Gas System to provide the necessary air supply to the ADS valves. The Accumulator Backup Compressed Gas System Pressure—Low Function is assumed to be OPERABLE and capable of automatically aligning the Accumulator Backup Compressed Gas System during the accidents analyzed in References 2, 4, 5, and 6. |C

Accumulator Backup Compressed Gas System Pressure—Low signals are initiated from six pressure switches that sense the ADS air header supply pressure. The Accumulator Backup Compressed Gas System Pressure—Low Allowable Value is chosen to ensure an adequate air supply is available to the ADS valves.

Six channels of Accumulator Backup Compressed Gas System Pressure—Low Function are only required to be OPERABLE when ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. (Three channels input to Division 1 Accumulator Backup Compressed Gas subsystem and the other three channels input to Division 2 Accumulator Backup Compressed Gas subsystem.) Refer to LCO 3.5.1 for ADS Applicability Bases.

4.g, 5.f. Manual Initiation

The Manual Initiation switch and push button channels introduce signals into the ADS logic to provide manual initiation capability and are redundant to the automatic protective instrumentation. There are two switch and push buttons (with two channels per switch and push button) for each ADS trip system (total of four).

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.g, 5.f. Manual Initiation (continued)

The Manual Initiation Function is not assumed in any accident or transient analyses in the FSAR. However, the Function is retained for overall redundancy and diversity of the ADS function as required by the NRC in the plant licensing basis.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the switch and push buttons. Eight channels of the Manual Initiation Function (four channels per ADS trip system) are only required to be OPERABLE when the ADS is required to be OPERABLE. Refer to LCO 3.5.1 for ADS Applicability Bases.

ACTIONS

A Note has been provided to modify the ACTIONS related to ECCS 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 ECCS instrumentation channels provide appropriate compensatory measures for separate inoperable Condition entry for each inoperable ECCS instrumentation channel.

A.1

Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.5.1-1. The applicable Condition specified in the Table is Function dependent. Each time a channel is discovered to be inoperable, Condition A is entered for that channel and provides for transfer to the appropriate subsequent Condition.

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

Required Actions B.1 and B.2 are intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same variable result in

(continued)

BASES

ACTIONS

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

redundant automatic initiation capability being lost for the feature(s). Required Action B.1 features would be those that are initiated by Functions 1.a, 1.b, 2.a, and 2.b (e.g., low pressure ECCS). The Required Action B.2 feature would be HPCS. For Required Action B.1, redundant automatic initiation capability is lost if either (a) one or more Function 1.a channels and one or more Function 2.a channels are inoperable and untripped, or (b) one or more Function 1.b channels and one or more Function 2.b channels are inoperable and untripped. For Divisions 1 and 2, since each inoperable channel would have Required Action B.1 applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected portion of the associated Division of low pressure ECCS and DG to be declared inoperable. However, since channels in both Divisions are inoperable and untripped, and the Completion Times started concurrently for the channels in both Divisions, this results in the affected portions in both Divisions of ECCS and DG being concurrently declared inoperable. For Required Action B.2, redundant automatic initiation capability is lost if two Function 3.a or two Function 3.b channels are inoperable and untripped in the same trip system.

In this situation (loss of redundant automatic initiation capability), the 24 hour allowance of Required Action B.3 is not appropriate and the feature(s) associated with the inoperable, untripped channels must be declared inoperable within 1 hour. As noted (Note 1 to Required Action B.1 and Required Action B.2), the two Required Actions are only applicable in MODES 1, 2, and 3. In MODES 4 and 5, the specific initiation time of the ECCS is not assumed and the probability of a LOCA is lower. Thus, a total loss of initiation capability for 24 hours (as allowed by Required Action B.3) is allowed during MODES 4 and 5. Notes are also provided (Note 2 to Required Action B.1 and Required Action B.2) to delineate which Required Action is applicable for each Function that requires entry into Condition B if an associated channel is inoperable. This ensures that the proper loss of initiation capability check is performed.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock."

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ACTIONS

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

For Required Action B.1, the Completion Time only begins upon discovery that a redundant feature in both Divisions (e.g., any Division 1 ECCS and Division 2 ECCS) cannot be automatically initiated due to inoperable, untripped channels within the same variable as described in the paragraph above. For Required Action B.2, the Completion Time only begins upon discovery that the HPCS System cannot be automatically initiated due to two inoperable, untripped channels for the associated Function in the same trip system. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 8) to permit restoration of any 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 B.3. 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 inoperable channel in trip would result in an initiation), Condition H must be entered and its Required Action taken. | C

C.1 and C.2

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within the same variable result in redundant automatic initiation capability being lost for the feature(s). Required Action C.1 features would be those that are initiated by Functions 1.c, 1.d, 1.e, 1.f, 2.c, 2.d, 2.e, and 2.f (i.e., low pressure ECCS). For Functions 1.c, 1.d, 2.c, and 2.d, redundant automatic initiation capability is lost if the Function 1.c or 1.d channel concurrent with the Function 2.c or 2.d channel are inoperable. For Functions 1.e and 2.e, redundant automatic initiation capability is lost if the Function 1.e and Function 2.e channels are inoperable. For

(continued)

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ACTIONS

C.1 and C.2 (continued)

Functions 1.f and 2.f, redundant automatic initiation capability is lost if one Function 1.f channel and one Function 2.f channel are inoperable. Since each inoperable channel would have Required Action C.1 applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected portion of the associated Division to be declared inoperable. However, since channels in both Divisions are inoperable, and the Completion Times started concurrently for the channels in both Divisions, this results in the affected portions in both Divisions being concurrently declared inoperable. For Functions 1.c, 1.d, 2.c, and 2.d, the affected portion of the Divisions are LPCS, LPCI A, LPCI B, and LPCI C, respectively. For Functions 1.e and 2.e, the affected portions of the Division are LPCI A and LPCI B, respectively. For Functions 1.f and 2.f, the affected portions of the Division are the associated low pressure ECCS pumps (Divisions 1 and 2, respectively).

In this situation (loss of redundant automatic initiation capability), the 24 hour allowance of Required Action C.2 is not appropriate and the feature(s) associated with the inoperable channels must be declared inoperable within 1 hour. As noted (Note 1), the Required Action is only applicable in MODES 1, 2, and 3. In MODES 4 and 5, the specific initiation time of the ECCS is not assumed and the probability of a LOCA is lower. Thus, a total loss of automatic initiation capability for 24 hours (as allowed by Required Action C.2) is allowed during MODES 4 and 5.

Note 2 states that Required Action C.1 is only applicable for Functions 1.c, 1.d, 1.e, 1.f, 2.c, 2.d, 2.e, and 2.f. The Required Action is not applicable to Functions 1.i, 2.h, and 3.g (which also require entry into this Condition if a channel in these Functions is inoperable), since they are the Manual Initiation Functions and are not assumed in any accident or transient analysis. Thus, a total loss of manual initiation capability for 24 hours (as allowed by Required Action C.2) is allowed. Required Action C.1 is also not applicable to Function 3.c (which also requires entry into this Condition if a channel in this Function is inoperable), since the loss of one channel results in a loss

(continued)

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ACTIONS

C.1 and C.2 (continued)

of the Function (two-out-of-two logic). This loss was considered during the development of Reference 8 and considered acceptable for the 24 hours allowed by Required Action C.2.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action C.1, the Completion Time only begins upon discovery that the same feature in both Divisions (e.g., any Division 1 ECCS and Division 2 ECCS) cannot be automatically initiated due to inoperable channels within the same variable as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 8) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition H must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would either cause the initiation or would not necessarily result in a safe state for the channel in all events. | C

D.1, D.2.1, and D.2.2

Required Action D.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of automatic component initiation capability for the HPCS System. Automatic component initiation capability is lost if two Function 3.d channels or two Function 3.e channels are inoperable and untripped. In this situation (loss of automatic suction swap), the 24 hour allowance of Required Actions D.2.1 and D.2.2 is not appropriate and the HPCS System must be declared inoperable within 1 hour after discovery of loss of HPCS initiation capability. As noted,

(continued)

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ACTIONS

D.1, D.2.1, and D.2.2 (continued)

the Required Action is only applicable if the HPCS pump suction is not aligned to the suppression pool, since, if aligned, the Function is already performed.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action D.1, the Completion Time only begins upon discovery that the HPCS System cannot be automatically aligned to the suppression pool due to two inoperable, untripped channels in the same Function. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 8) to permit restoration of any 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 D.2.1 or the suction source must be aligned to the suppression pool per Required Action D.2.2. Placing the inoperable channel in trip performs the intended function of the channel (shifting the suction source to the suppression pool). Performance of either of these two Required Actions will allow operation to continue. If Required Action D.2.1 or Required Action D.2.2 is performed, measures should be taken to ensure that the HPCS System piping remains filled with water. Alternately, if it is not desired to perform Required Actions D.2.1 and D.2.2 (e.g., as in the case where shifting the suction source could drain down the HPCS suction piping), Condition H must be entered and its Required Action taken.

E.1 and E.2

Required Action E.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within the LPCS and LPCI Pump Discharge Flow—Low (Minimum Flow) Functions result in redundant automatic initiation capability being lost for the feature(s). For Required

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

Action E.1, the features would be those that are initiated by Functions 1.g, 1.h, and 2.g (e.g., low pressure ECCS). Redundant automatic initiation capability is lost if three of the four channels associated with Functions 1.g, 1.h, and 2.g are inoperable. Since each inoperable channel would have Required Action E.1 applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected low pressure ECCS pump to be declared inoperable. However, since channels for more than one low pressure ECCS pump are inoperable, and the Completion Times started concurrently for the channels of the low pressure ECCS pumps, this results in the affected low pressure ECCS pumps being concurrently declared inoperable.

In this situation (loss of redundant automatic initiation capability), the 7 day allowance of Required Action E.2 is not appropriate and the feature(s) associated with each inoperable channel must be declared inoperable within 1 hour after discovery of loss of initiation capability for feature(s) in both Divisions. As noted (Note 1 to Required Action E.1), Required Action E.1 is only applicable in MODES 1, 2, and 3. In MODES 4 and 5, the specific initiation time of the low pressure ECCS is not assumed and the probability of a LOCA is lower. Thus, a total loss of initiation capability for 7 days (as allowed by Required Action E.2) is allowed during MODES 4 and 5. A Note is also provided (Note 2 to Required Action E.1) to delineate that Required Action E.1 is only applicable to low pressure ECCS Functions. Required Action E.1 is not applicable to HPCS Function 3.f since the loss of one channel results in a loss of the Function (one-out-of-one logic). This loss was considered during the development of Reference 8 and considered acceptable for the 7 days allowed by Required Action E.2. 1C

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action E.1, the Completion Time only begins upon discovery that three channels of the variable (Pump Discharge Flow–Low) cannot be automatically initiated due

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

to inoperable channels. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

If the instrumentation that controls the pump minimum flow valve is inoperable such that the valve will not automatically open, extended pump operation with no injection path available could lead to pump overheating and failure. If there were a failure of the instrumentation such that the valve would not automatically close, a portion of the pump flow could be diverted from the reactor injection path, causing insufficient core cooling. These consequences can be averted by the operator's manual control of the valve, which would be adequate to maintain ECCS pump protection and required flow. Furthermore, other ECCS pumps would be sufficient to complete the assumed safety function if no additional single failure were to occur. The 7 day Completion Time of Required Action E.2 to restore the inoperable channel to OPERABLE status is reasonable based on the remaining capability of the associated ECCS subsystems, the redundancy available in the ECCS design, and the low probability of a DBA occurring during the allowed out of service time. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition H must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would not necessarily result in a safe state for the channel in all events.

F.1 and F.2

Required Action F.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within similar ADS trip system Functions result in automatic initiation capability being lost for the ADS. Automatic initiation capability is lost if either (a) one or more Function 4.a channel and one or more Function 5.a channel are inoperable and untripped, (b) one Function 4.c channel and one Function 5.c channel are inoperable and untripped, or (c) two or more Function 4.f channels and two or more Function 5.e channels are inoperable and untripped.

(continued)

BASES

ACTIONS

F.1 and F.2 (continued)

In this situation (loss of automatic initiation capability), the 96 hour or 8 day allowance, as applicable, of Required Action F.2 is not appropriate, and all ADS valves must be declared inoperable within 1 hour after discovery of loss of ADS initiation capability in both trip systems.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action F.1, the Completion Time only begins upon discovery that the ADS cannot be automatically initiated due to inoperable, untripped channels within similar ADS trip system Functions as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 8 days has been shown to be acceptable (Ref. 8) to permit restoration of any inoperable channel to OPERABLE status if both HPCS and RCIC are OPERABLE. If either HPCS or RCIC is inoperable, the time is shortened to 96 hours. If the status of HPCS or RCIC changes such that the Completion Time changes from 8 days to 96 hours, the 96 hours begins upon discovery of HPCS or RCIC inoperability. However, total time for an inoperable, untripped channel cannot exceed 8 days. If the status of HPCS or RCIC changes such that the Completion Time changes from 96 hours to 8 days, the "time zero" for beginning the 8 day "clock" begins upon discovery of the inoperable, untripped channel. 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 F.2. 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 inoperable channel in trip would result in an initiation), Condition H must be entered and its Required Action taken. | C

(continued)

BASES

ACTIONS (continued)

G.1 and G.2

Required Action G.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within similar ADS trip system Functions result in automatic initiation capability being lost for the ADS. Automatic initiation capability is lost if either (a) one Function 4.b channel and one Function 5.b channel are inoperable, (b) one or more Function 4.d channels and one or more Function 5.d channels are inoperable, or (c) one or more Function 4.e channels and one or more Function 5.d channels are inoperable.

In this situation (loss of automatic initiation capability), the 96 hour or 8 day allowance, as applicable, of Required Action G.2 is not appropriate, and all ADS valves must be declared inoperable within 1 hour after discovery of loss of ADS initiation capability in both trip systems. The Note to Required Action G.1 states that Required Action G.1 is only applicable for Functions 4.b, 4.d, 4.e, 5.b, and 5.d. Required Action G.1 is not applicable to Functions 4.g and 5.f (which also require entry into this Condition if a channel in these Functions is inoperable), since they are the Manual Initiation Functions and are not assumed in any accident or transient analysis. Thus, a total loss of manual initiation capability for 96 hours or 8 days (as allowed by Required Action G.2) is allowed.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action G.1, the Completion Time only begins upon discovery that the ADS cannot be automatically initiated due to inoperable channels within similar ADS trip system Functions, as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 8 days has been shown to be acceptable (Ref. 8) to permit restoration of any inoperable channel to OPERABLE status if both HPCS and RCIC are OPERABLE (Required Action G.2). If either HPCS or RCIC is inoperable, the time is reduced to 96 hours. If the status

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

of HPCS or RCIC changes such that the Completion Time changes from 8 days to 96 hours, the 96 hours begins upon discovery of HPCS or RCIC inoperability. However, total time for an inoperable channel cannot exceed 8 days. If the status of HPCS or RCIC changes such that the Completion Time changes from 96 hours to 8 days, the "time zero" for beginning the 8 day "clock" begins upon discovery of the inoperable channel. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition H must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would not necessarily result in a safe state for the channel in all events.

H.1

With any Required Action and associated Completion Time not met, the associated feature(s) may be incapable of performing the intended function and the supported feature(s) associated with the inoperable untripped channels must be declared inoperable immediately.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each ECCS instrumentation Function are found in the SRs column of Table 3.3.5.1-1.

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 6 hours as follows: (a) for Functions 3.c, 3.f, and 3.g; and (b) for Functions other than 3.c, 3.f, and 3.g provided the associated Function or redundant Function maintains ECCS initiation capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 8) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the ECCS will initiate when necessary.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the 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 8. 1C

SR 3.3.5.1.3, SR 3.3.5.1.4, and SR 3.3.5.1.5 1B

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

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

adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

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.

SR 3.3.5.1.7

This SR ensures that the ECCS RESPONSE TIME for each ECCS injection/spray subsystem is less than or equal to the maximum value assumed in the accident analysis. However, failure to meet an ECCS RESPONSE TIME due to component failure other than instrumentation does not require the associated instrumentation to be declared inoperable; only the affected component is required to be declared inoperable. Response time testing acceptance criteria are included in Reference 9.

ECCS RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS. The 24 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.

(continued)

BASES (continued)

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," Revision 2, July 1993. C
6. CE-NPSD-801-P, "WNP-2 LOCA Analysis Report," May 1996. C
7. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132). C
8. NEDC-30936-P-A, "BWR Owners' Group Technical Specification Improvement Analyses for ECCS Actuation Instrumentation, Part 2," December 1988. C
9. Licensee Controlled Specifications Manual. C

B 3.3 INSTRUMENTATION

B 3.3.5.2 Reactor Core Isolation Cooling (RCIC) System Instrumentation

BASES

BACKGROUND

The purpose of the RCIC System instrumentation is to initiate actions to ensure adequate core cooling when the reactor vessel is isolated from its primary heat sink (the main condenser) and normal coolant makeup flow from the Reactor Feedwater System is insufficient or unavailable, such that RCIC System initiation occurs and maintains sufficient reactor water level such that initiation of the low pressure Emergency Core Cooling Systems (ECCS) pumps does not occur. A more complete discussion of RCIC System operation is provided in the Bases of LCO 3.5.3, "RCIC System."

The RCIC System may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level—Low Low, Level 2. The variable is monitored by four differential pressure switches. The switch contacts are arranged in a one-out-of-two taken twice logic arrangement. The logic can also be initiated by use of a manual switch and push button, whose two contacts are arranged in a two-out-of-two logic. Once initiated, the RCIC logic seals in and can be reset by the operator only when the reactor vessel water level signals have cleared.

The RCIC test line isolation valve is closed on a RCIC initiation signal to allow full system flow.

The RCIC System also monitors the water levels in the condensate storage tanks (CST) since this is the initial source of water for RCIC operation. Reactor grade water in the CST is the normal source. Upon receipt of a RCIC initiation signal, the CST suction valve is automatically signaled to open (it is normally in the open position) unless the pump suction valve from the suppression pool is open. If the water level in the CST falls below a preselected level, first the suppression pool suction valve automatically opens and then the CST suction valve automatically closes. Two level switches are used to detect low water level in the CST. Either switch can cause the suppression pool suction valve to open and the CST suction valve to close (one-out-of-two logic). To prevent losing

(continued)

BASES

BACKGROUND (continued)

suction to the pump, the suction valves are interlocked so that one suction path must be open before the other automatically closes.

The RCIC System provides makeup water to the reactor until the reactor vessel water level reaches the high water level (Level 8) trip (two-out-of-two logic), at which time the RCIC steam supply valve closes (the injection valve also closes due to the closure of the steam supply valve). The RCIC System restarts if vessel level again drops to the low level initiation point (Level 2).

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The function of the RCIC System, to provide makeup coolant to the reactor, is to respond to transient events. The RCIC System is not an Engineered Safety Feature System and no credit is taken in the safety analysis for RCIC System operation. Based on its contribution to the reduction of overall plant risk, however, the RCIC System, and therefore its instrumentation, meets Criterion 4 of the NRC Policy Statement (Ref. 1). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

The OPERABILITY of the RCIC System instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.5.2-1. Each Function must have a required number of OPERABLE channels with their setpoints within the specified Allowable Values, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each RCIC System instrumentation Function specified in the Table. 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 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)	(e.g., reactor vessel water level), 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 obtained from the 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 individual Functions are required to be OPERABLE in MODE 1, and in MODES 2 and 3 with reactor steam dome pressure > 150 psig, since this is when RCIC is required to be OPERABLE. Refer to LCO 3.5.3 for Applicability Bases for the RCIC System.

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

1. Reactor Vessel Water Level — Low Low, Level 2

Low reactor pressure vessel (RPV) water level indicates that normal feedwater flow is insufficient to maintain reactor vessel water level and that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, the RCIC System is initiated at Level 2 to assist in maintaining water level above the top of the active fuel.

Reactor Vessel Water Level — Low Low, Level 2 signals are initiated from four differential pressure switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

The Reactor Vessel Water Level — Low Low, Level 2 Allowable Value is set high enough such that for complete loss of feedwater flow, the RCIC System flow with high pressure core spray assumed to fail will be sufficient to avoid initiation of low pressure ECCS at Level 1.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Reactor Vessel Water Level — Low Low, Level 2 (continued)

Four channels of Reactor Vessel Water Level — Low Low, Level 2 Function are available and are required to be OPERABLE when RCIC is required to be OPERABLE to ensure that no single instrument failure can preclude RCIC initiation. Refer to LCO 3.5.3 for RCIC Applicability Bases.

2. Reactor Vessel Water Level — High, Level 8

High RPV water level indicates that sufficient cooling water inventory exists in the reactor vessel such that there is no danger to the fuel. Therefore, the Level 8 signal is used to close the RCIC steam supply valve to prevent overflow into the main steam lines (MSLs). (The injection valve also closes due to the closure of the steam supply valve.)

Reactor Vessel Water Level — High, Level 8 signals for RCIC are initiated from two differential pressure switches from the narrow range water level measurement instrumentation, which sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

The Reactor Vessel Water Level — High, Level 8 Allowable Value is high enough to preclude isolating the injection valve of the RCIC during normal operation, yet low enough to trip the RCIC System prior to water overflowing into the MSLs.

Two channels of Reactor Vessel Water Level — High, Level 8 Function are available and are required to be OPERABLE when RCIC is required to be OPERABLE to ensure that no single instrument failure can preclude RCIC initiation. Refer to LCO 3.5.3 for RCIC Applicability Bases.

3. Condensate Storage Tank Level — Low

Low level in the CST indicates the unavailability of an adequate supply of makeup water from this normal source. Normally the suction valve between the RCIC pump and the CST is open and, upon receiving a RCIC initiation signal, water for RCIC injection would be taken from the CST. However, if the water level in the CST falls below a preselected level,

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Condensate Storage Tank Level - Low (continued)

first the suppression pool suction valve automatically opens and then the CST suction valve automatically closes. This ensures that an adequate supply of makeup water is available to the RCIC pump. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valve must be open before the CST suction valve automatically closes.

Two level switches are used to detect low water level in the CST. The Condensate Storage Tank Level - Low Function Allowable Value is set high enough to ensure adequate pump suction head while water is being taken from the CST.

Two channels of Condensate Storage Tank Level - Low Function are available and are required to be OPERABLE when RCIC is required to be OPERABLE to ensure that no single instrument failure can preclude RCIC swap to suppression pool source. Refer to LCO 3.5.3 for RCIC Applicability Bases.

4. Manual Initiation

The Manual Initiation switch and push button channels introduce a signal into the RCIC System initiation logic that is redundant to the automatic protective instrumentation and provides manual initiation capability. There is one switch and push button (with two channels) for the RCIC System.

The Manual Initiation Function is not assumed in any accident or transient analyses in the FSAR. However, the Function is retained for overall redundancy and diversity of the RCIC function as required by the NRC in the plant licensing basis.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the switch and push button. Two channels of Manual Initiation are required to be OPERABLE when RCIC is required to be OPERABLE. Refer to LCO 3.5.3 for RCIC Applicability Bases.

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BASES (continued)

ACTIONS

A Note has been provided to modify the ACTIONS related to RCIC System 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 RCIC System instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable RCIC System instrumentation channel.

A.1

Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.5.2-1 in the accompanying LCO. The applicable Condition referenced in the Table is Function dependent. Each time a channel is discovered to be inoperable, Condition A is entered for that channel and provides for transfer to the appropriate subsequent Condition.

B.1 and B.2

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of automatic initiation capability for the RCIC System. In this case, automatic initiation capability is lost if two Function 1 channels in the same trip system are inoperable and untripped. In this situation (loss of automatic initiation capability), the 24 hour allowance of Required Action B.2 is not appropriate, and the RCIC System must be declared inoperable within 1 hour after discovery of loss of RCIC initiation capability.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action B.1, the Completion Time only begins

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

upon discovery that the RCIC System cannot be automatically initiated due to two inoperable, untripped Reactor Vessel Water Level — Low Low, Level 2 channels in the same trip system. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the redundancy of sensors available to provide initiation signals and the fact that the RCIC System is not assumed in any accident or transient analysis, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 2) to permit restoration of any 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 B.2. 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 inoperable channel in trip would result in an initiation), Condition E must be entered and its Required Action taken.

C.1

A risk based analysis was performed and determined that an allowable out of service time of 24 hours (Ref. 2) is acceptable to permit restoration of any inoperable channel to OPERABLE status (Required Action C.1). A Required Action (similar to Required Action B.1), limiting the allowable out of service time if a loss of automatic RCIC initiation capability exists, is not required. This Condition applies to the Reactor Vessel Water Level — High, Level 8 Function, whose logic is arranged such that any inoperable channel will result in a loss of automatic RCIC initiation capability (loss of high water level trip capability). As stated above, this loss of automatic RCIC initiation capability was analyzed and determined to be acceptable. This Condition also applies to the Manual Initiation Function. Since this Function is not assumed in any

(continued)

BASES

ACTIONS

C.1 (continued)

accident or transient analysis, a total loss of manual initiation capability (Required Action C.1) for 24 hours is allowed. The Required Action does not allow placing a channel in trip since this action would not necessarily result in the safe state for the channel in all events.

D.1, D.2.1, and D.2.2

Required Action D.1 is intended to ensure that appropriate actions are taken if multiple inoperable, untripped channels within the same Function result in automatic component initiation capability being lost for the feature(s). For Required Action D.1, the RCIC System is the only associated feature. In this case, automatic component initiation capability is lost if two Function 3 channels are inoperable and untripped. In this situation (loss of automatic suction swap), the 24 hour allowance of Required Actions D.2.1 and D.2.2 is not appropriate, and the RCIC System must be declared inoperable within 1 hour from discovery of loss of RCIC initiation capability. As noted, Required Action D.1 is only applicable if the RCIC pump suction is not aligned to the suppression pool since, if aligned, the Function is already performed.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action D.1, the Completion Time only begins upon discovery that the RCIC System cannot be automatically aligned to the suppression pool due to two inoperable, untripped channels in the same Function. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the redundancy of sensors available to provide initiation signals and the fact that the RCIC System is not assumed in any accident or transient analysis, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 2) to permit restoration of any 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

(continued)

BASES

ACTIONS

D.1, D.2.1, and D.2.2 (continued)

tripped condition per Required Action D.2.1, which performs the intended function of the channel (shifting the suction source to the suppression pool). Alternatively, Required Action D.2.2 allows the manual alignment of the RCIC suction to the suppression pool, which also performs the intended function. If Required Action D.2.1 or D.2.2 is performed, measures should be taken to ensure that the RCIC System piping remains filled with water. If it is not desired to perform Required Actions D.2.1 and D.2.2 (e.g., as in the case where shifting the suction source could drain down the RCIC suction piping), Condition E must be entered and its Required Action taken.

E.1

With any Required Action and associated Completion Time not met, the RCIC System may be incapable of performing the intended function, and the RCIC System must be declared inoperable immediately.

SURVEILLANCE REQUIREMENTS

As noted in the beginning of the SRs, the SRs for each RCIC System instrumentation Function are found in the SRs column of Table 3.3.5.2-1.

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 as follows: (a) for up to 6 hours for Functions 2 and 4; and (b) for up to 6 hours for Functions 1 and 3 provided the associated Function maintains trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 2) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the RCIC will initiate when necessary.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.2.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the 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 that 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 3.3.5.2.2

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 analysis of Reference 2.

SR 3.3.5.2.3

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.2.3 (continued)

adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

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

SR 3.3.5.2.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.5.3 overlaps this Surveillance to provide complete testing of the safety function.

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

REFERENCES

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

2. GENE-770-06-2-A, "Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," December 1992.

B 3.3 INSTRUMENTATION

B 3.3.6.1 Primary Containment Isolation Instrumentation

BASES

BACKGROUND

The primary containment isolation instrumentation automatically initiates closure of appropriate primary containment isolation valves (PCIVs). The function of the PCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs). Primary containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a DBA.

The isolation instrumentation includes the sensors, relays, and switches that are necessary to cause initiation of primary containment and reactor coolant pressure boundary (RCPB) isolation. Most channels include electronic equipment (e.g., trip relays) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel outputs a primary containment isolation signal to the isolation logic. Functional diversity is provided by monitoring a wide range of independent parameters. The input parameters to the isolation logic are (a) reactor vessel water level, (b) area and differential temperatures, (c) main steam line (MSL) flow measurement, (d) Standby Liquid Control (SLC) System initiation, (e) condenser vacuum loss, (f) main steam line pressure, (g) reactor core isolation cooling (RCIC) steam line flow and time delay relay, (h) ventilation exhaust plenum radiation, (i) RCIC steam line pressure, (j) RCIC turbine exhaust diaphragm pressure, (k) reactor water cleanup (RWCU) differential and blowdown flows and time delay relay, (l) reactor vessel pressure, and (m) drywell pressure. Redundant sensor input signals are provided from each such isolation initiation parameter. In addition, manual isolation of the logics is provided.

The primary containment isolation instrumentation has inputs to the trip logic from the isolation Functions listed below.

(continued)

BASES

BACKGROUND (continued)

1. Main Steam Line Isolation

Most Main Steam Line Isolation Functions receive inputs from four channels. The outputs from these channels are combined in one-out-of-two taken twice logic to initiate isolation of all main steam isolation valves (MSIVs). The outputs from the same channels are arranged into two two-out-of-two trip systems to isolate all MSL drain valves. One two-out-of-two trip system is associated with the inboard valve and the other two-out-of-two logic trip system is associated with the outboard valves.

The exceptions to this arrangement are the Main Steam Line Flow—High and the Manual Initiation Functions. The Main Steam Line Flow—High Function uses 16 flow channels, four for each steam line. One channel from each steam line inputs to one of four trip strings. Two trip strings make up each trip system, and both trip systems must trip to cause an MSL isolation. Each trip string has four inputs (one per MSL), any one of which will trip the trip string. The trip strings within a trip system are arranged in a one-out-of-two taken twice logic. Therefore, this is effectively a one-out-of-eight taken twice logic arrangement to initiate isolation of the MSIVs. Similarly, the 16 flow channels are connected into two two-out-of-two logic trip systems (effectively, two one-out-of-four twice logic), with one trip system isolating the inboard MSL drain valve and the other trip system isolating the outboard MSL drain valves. The Manual Initiation Function uses eight channels, two per each switch and push button. The four channels from two switch and push buttons input into one trip system and the four channels from the other two switch and push buttons input into the other trip system. To close all MSIVs, both trip systems must actuate, similar to all the other Functions described above. However, the logic of each trip system is arranged such that both channels from one of the associated switch and push buttons are required to actuate the trip system (i.e., the switch and push button must be both armed and depressed for the trip system to actuate). To close the MSL drain valves, all channels in both trip systems must actuate (i.e., both channels from each of the two associated switch and push buttons are required to actuate the inboard valve trip system and both channels from each of the tow associated switch and push buttons are required to actuate the outboard valve trip system).

MSL Isolation Functions isolate the Group 1 valves.

(continued)

BASES

BACKGROUND (continued)

2. Primary Containment Isolation

Most Primary Containment Isolation Functions receive inputs from four channels. The outputs from these channels are arranged into two-out-of-two logic trip systems. For the Manual Initiation Function of the Group 3 PCIVs, four channels are required to actuate a trip system (a four-out-of-four logic trip system). One trip system initiates isolation of all inboard PCIVs, while the other trip system initiates isolation of all outboard PCIVs. Each trip system logic closes one of the two valves on each penetration so that operation of either trip system isolates the penetration.

The exceptions to this arrangement are the Traversing In-core Probe (TIP) System valves/drives and the Group 5 PCIVs. For the TIP System valves and drive mechanisms, only one trip system (the inboard valve system) is provided. When the trip system actuates, the drive mechanisms withdraw the TIPs, and when the TIPs are fully withdrawn, the ball valves close. The Group 5 PCIVs need only one trip system (the inboard valve system) to isolate all Group 5 valves.

Reactor Vessel Level—Low, Level 3 Function isolates the Group 5 valves. Reactor Vessel Water Level—Low, Low, Level 2 Function isolates the Group 2, 3, and 4 valves. Drywell Pressure—High and Manual Initiation Functions isolates the Group 2, 3, 4, and 5 valves. Reactor Building Vent Exhaust Plenum Radiation—High Function isolates the Group 3 valves.

3. Reactor Core Isolation Cooling System Isolation

Most Functions receive input from two channels, with each channel in one trip system using one-out-of-one logic. One of the two trip systems is connected to the inboard valves and the other trip system is connected to the outboard valve on the RCIC penetration so that operation of either trip system isolates the penetration. The exceptions to this arrangement are the RCIC Steam Supply Pressure—Low and the RCIC Turbine Exhaust Diaphragm Pressure—High Functions. These Functions receive input from four steam supply pressure and four turbine exhaust diaphragm pressure channels, respectively. The outputs from these channels are connected into two-out-of-two trip systems, each trip

(continued)

BASES

BACKGROUND

3. Reactor Core Isolation Cooling System Isolation (continued)

system isolating the inboard or outboard RCIC valves. In addition, the RCIC System Isolation Manual Initiation Function has only one channel, which isolates the outboard RCIC valve only (provided an automatic initiation signal is present).

RCIC Isolation Functions isolate the Group 8 valves.

4. Reactor Water Cleanup System Isolation

Most Functions receive input from two channels with each channel in one trip system using one-out-of-one logic. Functions 4.f and 4.g (Pump Room Area Temperature and Differential Temperature—High) have one channel in each trip system in each room for a total of four channels per Function, and Function 4.i (RWCU Line Routing Area Temperature—High) has one channel in each trip system in each room for a total of eight channels per Function, but the logic is the same (one-out-of-one). Each of the two trip systems is connected to one of the two valves on the RWCU penetration so that operation of either trip system isolates the penetration. The exceptions to this arrangement are the Reactor Vessel Water Level—Low Low, Level 2, the SLC System Initiation, and the Manual Initiation Functions. The Reactor Vessel Water Level—Low Low, Level 2 Function receives input from four reactor vessel water level channels. The outputs from the reactor vessel water level channels are connected into two-out-of-two trip systems, each trip system isolating one of the two RWCU valves. The SLC System Initiation Function receives input from two channels (one from each SLC pump). The outputs are connected into a one-out-of-two trip system, with the trip system closing only the outboard valve. The Manual Initiation Function uses four channels, two per each switch and push button. Both channels from one switch and push button input into one trip system and both channels from the other switch and push button input into the other trip system, with the channels connected in a two-out-of-two logic. Each trip system isolates one of the two RWCU valves.

RWCU Isolation Functions isolate the Group 7 valves.

(continued)

BASES

BACKGROUND (continued)

5. RHR Shutdown Cooling System Isolation

Most Functions receive input from two channels with each channel in one trip system using one-out-of-one logic. Functions 5.a and 5.b (Pump Room Area Temperature and Pump Room Area Ventilation Differential Temperature—High) have one channel in each trip system in each room for a total of four channels per Function, and Function 5.c (Heat Exchanger Area Temperature—High) has one channel in each trip system in each room for a total of eight channels per Function, but the logic is the same (one-out-of-one). One of the two trip systems is connected to the outboard valves on each shutdown cooling penetration (reactor vessel head spray, shutdown cooling return, and shutdown cooling suction lines) and the other trip system is connected to the inboard valve on the shutdown cooling suction line penetration so that operation of either trip system isolates the penetrations. The exceptions to this arrangement are the Reactor Vessel Water Level—Low, Level 3 and the Manual Initiation Functions. The Reactor Vessel Water Level—Low, Level 3 Function receives input from four reactor vessel water level channels. The outputs from the reactor vessel water level channels are connected into two two-out-of-two trip systems, each trip system isolating the inboard or outboard valves. The Manual Initiation Function uses four channels, two per each switch and push button. Both channels from one switch and push button input into one trip system and both channels from the other switch and push button input into the other trip system, with the channels connected in a two-out-of-two logic. One trip system isolates the inboard valve and the other trip system isolates the outboard valves.

The RHR Shutdown Cooling Isolation Functions isolate the Group 6 valves.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The isolation signals generated by the primary containment isolation instrumentation are implicitly assumed in the safety analyses of References 1 and 2 to initiate closure of valves to limit offsite doses. Refer to LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)," Applicable Safety Analyses Bases, for more detail.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Primary containment isolation instrumentation satisfies Criterion 3 of the NRC Policy Statement (Ref. 3). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

The OPERABILITY of the primary containment instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.6.1-1. Each Function must have a required number of OPERABLE channels, with their setpoints within the specified Allowable Values, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Each channel must also respond within its assumed response time, where appropriate.

Allowable Values are specified for each Primary Containment Isolation Function specified in the Table. 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 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., reactor vessel water level), 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 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.

Certain Emergency Core Cooling Systems (ECCS) and RCIC valves (e.g., minimum flow) also serve the dual function of automatic PCIVs. The signals that isolate these valves are also associated with the automatic initiation of the ECCS

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

and RCIC. Some instrumentation and ACTIONS associated with these signals are addressed in LCO 3.3.5.1, "ECCS Instrumentation," and LCO 3.3.5.2, "RCIC System Instrumentation," and are not included in this LCO.

In general, the individual Functions are required to be OPERABLE in MODES 1, 2, and 3 consistent with the Applicability for LCO 3.6.1.1, "Primary Containment." Functions that have different Applicabilities are discussed below in the individual Functions discussion.

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

1. Main Steam Line Isolation

1.a. Reactor Vessel Water Level—Low Low, Level 2

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of the MSIVs and other interfaces with the reactor vessel occurs to prevent offsite dose limits from being exceeded. The Reactor Vessel Water Level—Low Low, Level 2 Function is one of the many Functions assumed to be OPERABLE and capable of providing isolation signals. The Reactor Vessel Water Level—Low Low, Level 2 Function associated with isolation is assumed in the analysis of the recirculation line break (Ref. 1). The isolation of the MSL on Level 2 supports actions to ensure that offsite dose limits are not exceeded for a DBA.

Reactor vessel water level signals are initiated from four differential pressure switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level—Low Low, Level 2 Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.a. Reactor Vessel Water Level—Low Low, Level 2 (continued)

The Reactor Vessel Water Level—Low Low, Level 2 Allowable Value is chosen to be the same as the ECCS Level 2 Allowable Value (LCO 3.3.5.1) to ensure that the MSLs isolate on a potential loss of coolant accident (LOCA) to prevent offsite doses from exceeding 10 CFR 100 limits.

This Function isolates the Group 1 valves.

1.b. Main Steam Line Pressure—Low

Low MSL pressure indicates that there may be a problem with the turbine pressure regulation, which could result in a low reactor vessel water level condition and the RPV cooling down more than 100°F/hour if the pressure loss is allowed to continue. The Main Steam Line Pressure—Low Function is directly assumed in the analysis of the pressure regulator failure (Ref. 4). For this event, the closure of the MSIVs ensures that the RPV temperature change limit (100°F/hour) is not reached. In addition, this Function supports actions to ensure that Safety Limit 2.1.1.1 is not exceeded. (This Function closes the MSIVs prior to pressure decreasing below 785 psig, which results in a scram due to MSIV closure, thus reducing reactor power to < 25% RTP.)

The MSL low pressure signals are initiated from four sensors that are connected to the MSL header. The sensors are arranged such that, even though physically separated from each other, each sensor is able to detect low MSL pressure. Four channels of Main Steam Line Pressure—Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was selected to be high enough to prevent excessive RPV depressurization.

The Main Steam Line Pressure—Low Function is only required to be OPERABLE in MODE 1 since this is when the assumed transient can occur (Ref. 4).

This Function isolates the Group 1 valves.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1.c. Main Steam Line Flow—High

Main Steam Line Flow—High is provided to detect a break of the MSL and to initiate closure of the MSIVs. If the steam were allowed to continue flowing out of the break, the reactor would depressurize and the core could uncover. If the RPV water level decreases too far, fuel damage could occur. Therefore, the isolation is initiated on high flow to prevent or minimize core damage. The Main Steam Line Flow—High Function is directly assumed in the analysis of the main stream line break (MSLB) accident (Ref. 5). The isolation action, along with the scram function of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46 and offsite doses do not exceed the 10 CFR 100 limits.

The MSL flow signals are initiated from 16 differential pressure switches that are connected to the four MSLs (the differential pressure switches sense d/p across a flow restrictor). The differential pressure switches are arranged such that, even though physically separated from each other, all four connected to one steam line would be able to detect the high flow. Four channels of Main Steam Line Flow—High Function for each MSL (two channels per trip system) are available and are required to be OPERABLE so that no single instrument failure will preclude detecting a break in any individual MSL.

The Allowable Value is chosen to ensure that offsite dose limits are not exceeded due to the break.

This Function isolates the Group 1 valves.

1.d. Condenser Vacuum—Low

The Condenser Vacuum—Low Function is provided to prevent overpressurization of the main condenser in the event of a loss of the main condenser vacuum (Ref. 6). Since the integrity of the condenser is an assumption in offsite dose calculations (Ref. 7), the Condenser Vacuum—Low Function is assumed to be OPERABLE and capable of initiating closure of the MSIVs. The closure of the MSIVs is initiated to prevent the addition of steam that would lead to additional

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.d. Condenser Vacuum—Low (continued)

condenser pressurization and possible rupture of the diaphragm installed to protect the turbine exhaust hood, thereby preventing a potential radiation leakage path following an accident.

Condenser vacuum pressure signals are derived from four vacuum switches that sense the vacuum in the condenser. Four channels of Condenser Vacuum—Low Function are available and are required to be OPERABLE to ensure no single instrument failure can preclude the isolation function.

The Allowable Value is chosen to prevent damage to the condenser due to pressurization, thereby ensuring its integrity for offsite dose analysis. As noted (footnote (a) to Table 3.3.6.1-1), the channels are not required to be OPERABLE in MODES 2 and 3, when all turbine throttle valves (TTVs) are closed, since the potential for condenser overpressurization is minimized. Switches are provided to manually bypass the channels when all TTVs are closed.

This Function isolates the Group 1 valves.

1.e, 1.f. Main Steam Tunnel Temperature and Differential Temperature—High

Temperature and Differential Temperature—High is provided to detect a leak in a main steam line, and provides diversity to the high flow instrumentation. The isolation occurs when a very small leak has occurred. If the small leak is allowed to continue without isolation, offsite dose limits may be reached. However, credit for these instruments is not taken in any transient or accident analysis in the FSAR, since bounding analyses are performed for large breaks such as MSLBs.

Temperature—High signals are initiated from thermocouples located in the area being monitored. Four channels of Main Steam Tunnel Temperature—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. Each Function has one temperature element.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.e, 1.f. Main Steam Tunnel Temperature and Differential Temperature—High (continued)

Eight thermocouples provide input to the Main Steam Tunnel Differential Temperature—High Function. The output of these thermocouples is used to determine the differential temperature. Each channel consists of a differential temperature instrument that receives inputs from thermocouples that are located in the inlet and outlet of the area cooling system. Four channels of Main Steam Tunnel Differential Temperature—High Function are available and are required to be OPERABLE to ensure that no single instrument failure preclude the isolation function.

The ambient and differential temperature monitoring Allowable Value is chosen to detect a leak equivalent to 25 gpm.

These Functions isolate the Group 1 valves.

1.g. Manual Initiation

The Manual Initiation switch and push button channels introduce signals into the MSL isolation logic that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific FSAR safety analysis that takes credit for this Function. It is retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There are four switch and push buttons (with two channels per switch and push button) for the logic, with two switch and push buttons per trip system. Eight channels of Manual Initiation Function are available and are required to be OPERABLE in MODES 1, 2, and 3, since these are the MODES in which the MSL Isolation automatic Functions are required to be OPERABLE.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the switch and push buttons.

This Function isolates the Group 1 valves.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

2. Primary Containment Isolation

2.a, 2.b. Reactor Vessel Water Level — Low, Level 3 and Reactor Vessel Water Level — Low Low, Level 2

Low RPV water level indicates the capability to cool the fuel may be threatened. The valves whose penetrations communicate with the primary containment are isolated to limit the release of fission products. The isolation of the primary containment on Level 3 and 2 supports actions to ensure that offsite dose limits of 10 CFR 100 are not exceeded. The Reactor Vessel Water Level — Low, Level 3 and Reactor Vessel Water Level — Low Low, Level 2 Functions associated with isolation are implicitly assumed in the FSAR analysis as these leakage paths are assumed to be isolated post LOCA.

Reactor Vessel Water Level — Low, Level 3 and Reactor Vessel Water Level — Low Low, Level 2 signals are initiated from differential pressure switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level — Low, Level 3 Function and four channels of Reactor Vessel Water Level — Low Low, Level 2 Function are available and are required to be OPERABLE to ensure no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level — Low, Level 3 Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level — Low, Level 3 Allowable Value (LCO 3.3.1.1), and the Reactor Vessel Water Level — Low Low, Level 2 Allowable Value was chosen to be the same as the ECCS Reactor Vessel Water Level — Low Low, Level 2 Allowable Value (LCO 3.3.5.1), since isolation of these valves is not critical to orderly plant shutdown.

The Reactor Vessel Water Level — Low, Level 3 Function isolates the Group 5 valves. The Reactor Vessel Water Level — Low Low, Level 2 Function isolates the Group 2, 3, and 4 valves.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.c. Drywell Pressure—High

High drywell pressure can indicate a break in the RCPB inside the drywell. The isolation of some of the PCIVs on high drywell pressure supports actions to ensure that offsite dose limits of 10 CFR 100 are not exceeded. The Drywell Pressure—High Function associated with isolation of the primary containment is implicitly assumed in the FSAR accident analysis as these leakage paths are assumed to be isolated post LOCA.

High drywell pressure signals are initiated from pressure switches that sense the pressure in the drywell. Four channels of Drywell Pressure—High are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was selected to be the same as the RPS Drywell Pressure—High Allowable Value (LCO 3.3.5.1), since this may be indicative of a LOCA inside primary containment.

This Function isolates the Group 2, 3, 4, and 5 valves.

2.d. Reactor Building Vent Exhaust Plenum Radiation—High

High ventilation exhaust radiation is an indication of possible gross failure of the fuel cladding. The release may have originated from the primary containment due to a break in the RCPB. When Exhaust Radiation—High is detected, valves whose penetrations communicate with the primary containment atmosphere are isolated to limit the release of fission products.

The Reactor Building Vent Exhaust Plenum Radiation—High signals are initiated from radiation detectors that are located in the ventilation exhaust plenum. The signal from each detector is input to an individual monitor whose trip outputs are assigned to an isolation channel. Four channels of Reactor Building Vent Exhaust Plenum Radiation—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.d. Reactor Building Vent Exhaust Plenum Radiation—High (continued)

The Allowable Values are chosen to ensure offsite doses remain below 10 CFR 100 limits.

This Function isolates the Group 3 valves.

2.e. Manual Initiation

The Manual Initiation switch and push button channels introduce signals into the primary containment isolation logic that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific FSAR safety analysis that takes credit for this Function. It is retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

For the Group 3 valves, there are four switch and push buttons (with two channels per switch and push button) for the logic, with two switch and push buttons per trip system. For the Group 2, 4, and 5 valves, there are two switch and push buttons (with two channels per switch and push button) for the logic, one switch and push button per trip system. Eight channels of the Manual Initiation Function are available and are required to be OPERABLE in MODES 1, 2, and 3, since these are the MODES in which the Primary Containment Isolation automatic Functions are required to be OPERABLE.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the switch and push buttons.

This Function isolates the Group 2, 3, 4, and 5 valves.

3. Reactor Core Isolation Cooling System Isolation

3.a. RCIC Steam Line Flow—High

RCIC Steam Line Flow—High Function is provided to detect a break of the RCIC steam lines and initiates closure of the steam line isolation valves. If the steam is allowed to continue flowing out of the break, the reactor will

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.a. RCIC Steam Line Flow—High (continued)

depressurize and core uncovery can occur. Therefore, the isolation is initiated on high flow to prevent or minimize core damage. The isolation action, along with the scram function of the Reactor Protection System (RPS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. Specific credit for this Function is not assumed in any FSAR accident analyses since the bounding analysis is performed for large breaks such as recirculation and MSL breaks. However, these instruments prevent the RCIC steam line break from becoming bounding.

The RCIC Steam Line Flow—High signals are initiated from two differential pressure switches that are connected to the system steam lines. Two channels of RCIC Steam Line Flow—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value is chosen to be low enough to ensure that the trip occurs to prevent fuel damage and maintains the MSLB event as the bounding event.

This Function isolates the Group 8 valves.

3.b. RCIC Steam Line Flow—Time Delay

The RCIC Steam Line Flow—Time Delay is provided to prevent false isolations on RCIC Steam Line Flow—High during system startup transients and therefore improves system reliability. This Function is not assumed in any FSAR transient or accident analyses since the bounding analysis is performed for large breaks such as recirculation and MSL breaks. However, these instruments prevent the RCIC steam line break from becoming bounding.

The RCIC Steam Line Flow—Time Delay Function delays the RCIC Steam Line Flow—High signals by use of time delay relays. When an RCIC Steam Line Flow—High signal is generated, the time delay relays delay the tripping of the associated RCIC isolation trip system for a short time. Two channels of RCIC Steam Line Flow—Time Delay Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.b. RCIC Steam Line Flow—Time Delay (continued)

The Allowable Value was chosen to be long enough to prevent false isolations due to system starts but not so long as to impact offsite dose calculations.

This Function isolates the Group 8 valves.

3.c. RCIC Steam Supply Pressure—Low

Low RCIC steam supply pressure indicates that the pressure of the steam in the RCIC turbine may be too low to continue operation of the RCIC turbine. This isolation is for equipment protection and is not assumed in any transient or accident analysis in the FSAR. However, it also provides a diverse signal to indicate a possible system break. These instruments are included in the Technical Specifications (TS) because of the potential for risk due to possible failure of the instruments preventing RCIC initiations. Therefore, they meet Criterion 4 of the NRC Policy Statement (Ref. 3).

The RCIC Steam Supply Pressure—Low signals are initiated from four pressure switches that are connected to the RCIC steam line. Two channels of RCIC Steam Supply Pressure—Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

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

This Function isolates the Group 8 valves.

3.d. RCIC Turbine Exhaust Diaphragm Pressure—High

High turbine exhaust diaphragm pressure indicates that the pressure may be too high to continue operation of the RCIC turbine. That is, one of two exhaust diaphragms has ruptured and pressure is reaching turbine casing pressure limits. This isolation is for equipment protection and is not assumed in any transient or accident analysis in the FSAR. These instruments are included in the TS because of

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

the potential for risk due to possible failure of the instruments preventing RCIC initiations. Therefore, they meet Criterion 4 of the NRC Policy Statement (Ref. 3).

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

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

This Function isolates the Group 8 valves.

3.e, 3.f, 3.g. Area Temperature and Differential Temperature—High

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

Area Temperature—High signals are initiated from thermocouples that are located in the room that is being monitored. Two instruments for each Function monitor each associated area. Four channels of Area Temperature—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. There are two channels for the RCIC equipment room area and two channels for the RWCU/RCIC steam line routing area.

There are four thermocouples that provide input to the RCIC Equipment Room Area Differential Temperature—High Function. The output of these thermocouples is used to determine the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.e, 3.f, 3.g. Area Temperature and Differential Temperature—High (continued)

differential temperature. Each channel consists of a differential temperature instrument that receives inputs from thermocouples that are located in the inlet and outlet of the area cooling system for a total of two available channels. Two channels are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

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

This Function isolates the Group 8 valves.

3.h. Manual Initiation

The Manual Initiation push button channel introduces a signal into the RCIC System isolation logic that is redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific FSAR safety analysis that takes credit for this Function. It is retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There is one push button for RCIC. One channel of Manual Initiation Function is available and is required to be OPERABLE in MODES 1, 2, and 3 since these are the MODES in which the RCIC System Isolation automatic Functions are required to be OPERABLE. As noted (footnote (b) to Table 3.3.6.1-1), this Function is only required to close the outboard Group 8 RCIC isolation valve since the signal only provides input into one of the two trip systems.

There is no Allowable Value for this Function since the channel is mechanically actuated based solely on the position of the push button.

This Function isolates the outboard Group 8 valve.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

4. Reactor Water Cleanup System Isolation

4.a, 4.c. Differential Flow and Blowdown Flow—High

The high differential flow signal is provided to detect a break in the RWCU System. This will detect leaks in the RWCU System when area or differential temperature would not provide detection (i.e., a cold leg or blowdown piping break). Should the reactor coolant continue to flow out of the break, offsite dose limits may be exceeded. Therefore, isolation of the RWCU System is initiated when high differential flow or high blowdown flow is sensed to prevent exceeding offsite doses. A time delay (Function 4.b, described below) is provided to prevent spurious trips of the Differential Flow—High Function during most RWCU operational transients. These Functions are not assumed in any FSAR transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs.

The high differential flow signals are initiated from one flow element and transmitter that are connected to the inlet (from the reactor vessel) and two flow elements and transmitters from the outlets (to condenser and feedwater) of the RWCU System. The outputs of the transmitters are compared (in a common summer) and the output is sent to two flow switches. If the difference between the inlet and outlet flow is too large, each flow switch generates an isolation signal. Two channels of Differential Flow—High Function are available and are required to be OPERABLE to ensure that no single instrument failure in the logic downstream of the common summer can preclude the isolation function. Since some portions of the two channels are common (e.g., flow elements, transmitters, summer), both channels must be considered inoperable if a common component is inoperable.

The high blowdown flow signals are initiated from one flow element and two flow transmitters that are connected to the outlet (to condenser and radwaste) of the RWCU System. The outputs of the transmitters are sent to two flow switches. Two channels of Blowdown Flow—High Function are available and are required to be OPERABLE to ensure that no single instrument failure downstream of the common flow element can preclude the isolation function. Since the flow element is common, both channels must be considered inoperable if the flow element is inoperable.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	4.a, 4.c. Differential Flow and Blowdown Flow—High (continued)

The Differential Flow—High Allowable Value ensures that the break of the RWCU piping is detected. The Blowdown Flow—High Allowable Value ensures that the break of the RWCU blowdown piping is detected.

This Function isolates the Group 7 valves.

4.b. Differential Flow—Time Delay

The Differential Flow—Time Delay is provided to avoid RWCU System isolations due to operational transients (such as pump starts and mode changes). During these transients the inlet and return flows become unbalanced for short time periods and Differential Flow—High will be sensed without an RWCU System break being present. Credit for this Function is not assumed in the FSAR accident or transient analysis, since bounding analyses are performed for large breaks such as MSLBs.

The RWCU Differential Flow—Time Delay Function delays the RWCU Differential Flow—High signals by use of time delay relays. When an RWCU Differential Flow—High signal is generated, the time delay relays delay the tripping of the associated RWCU isolation trip system for a short time. Two channels for Differential Flow—Time Delay Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Differential Flow—Time Delay Allowable Value is selected to ensure that the MSLB outside containment remains the limiting break for FSAR analysis for offsite dose calculations.

This Function isolates the Group 7 valves.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

4.d, 4.e, 4.f, 4.g, 4.h, 4.i. Area Temperature and Differential Temperature—High

Area Temperature and Differential Temperature—High is provided to detect a leak from the RWCU System. The isolation occurs even when very small leaks have occurred and is diverse to the high differential flow instrumentation for the hot portions of the RWCU System. If the small leak continues without isolation, offsite dose limits may be reached. Credit for these instruments is not taken in any transient or accident analysis in the FSAR, since bounding analyses are performed for large breaks such as MSLBs.

Area Temperature—High signals are initiated from thermocouples that are located in the room that is being monitored. There are 16 thermocouples that provide input to the Area Temperature—High Functions (two per area). Sixteen channels are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. There are two channels for the heat exchanger room area, four channels for the pump room areas (two per room), two channels for the RWCU/RCIC line routing area, and eight channels for the RWCU line routing areas (two per room).

There are 12 thermocouples that provide input to the Differential Temperature—High Functions. The output of these thermocouples is used to determine the differential temperature. Each channel consists of a differential temperature instrument that receives inputs from thermocouples that are located in the inlet and outlet of the area cooling system for a total of six available channels (two per area). Six channels are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. There are two channels for the heat exchanger area and four channels for the pump room areas (two per room).

The Area Temperature and Differential Temperature—High Allowable Values are set low enough to detect a leak equivalent to 25 gpm.

These Functions isolate the Group 7 valves.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

4.j. Reactor Vessel Water Level—Low Low, Level 2

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of some reactor vessel interfaces occurs to isolate the potential sources of a break. The isolation of the RWCU System on Level 2 supports actions to ensure that fuel peak cladding temperature remains below the limits of 10 CFR 50.46. The Reactor Vessel Water Level—Low Low, Level 2 Function associated with RWCU isolation is not directly assumed in any transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs.

Reactor Vessel Water Level—Low Low, Level 2 signals are initiated from differential pressure switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level—Low Low, Level 2 Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level—Low Low, Level 2 Allowable Value was chosen to be the same as the ECCS Reactor Vessel Water Level—Low Low, Level 2 Allowable Value (LCO 3.3.5.1), since the capability to cool the fuel may be threatened.

This Function isolates the Group 7 valves.

4.k. SLC System Initiation

The isolation of the RWCU System is required when the SLC System has been initiated to prevent dilution and removal of the boron solution by the RWCU System (Ref. 8). SLC System initiation signals are initiated from the two SLC pump start signals.

Two channels (one from each pump) of SLC System Initiation Function are available and are required to be OPERABLE only in MODES 1 and 2, since these are the only MODES where the reactor can be critical, and these MODES are consistent with the Applicability for the SLC System (LCO 3.1.7). Compliance with Reference 9 (WNP-2 requires both SLC pumps be started to inject boron) ensures no single instrument

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.k. SLC System Initiation (continued)

failure can preclude the isolation function. As noted (footnote (c) to Table 3.3.6.1-1), this Function is only required to close the outboard Group 7 RWCU isolation valve since the signal only provides input into one of the two trip systems.

There is no Allowable Value associated with this Function since the channels are mechanically actuated based solely on the position of the SLC System initiation switch.

This Function isolates the Group 7 valves.

4.l. Manual Initiation

The Manual Initiation switch and push button channels introduce signals into the RWCU System isolation logic that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific FSAR safety analysis that takes credit for this Function. It is retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There are two switch and push buttons (with two channels per switch and push button) for the logic, one switch and push button per trip system. Four channels of the Manual Initiation Function are available and are required to be OPERABLE in MODES 1, 2, and 3 since these are the MODES in which the RWCU System Isolation automatic Functions are required to be OPERABLE.

There is no Allowable Value for this Function, since the channels are mechanically actuated based solely on the position of the switch and push buttons.

This Function isolates the Group 7 valves.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

5. RHR Shutdown Cooling System Isolation

5.a, 5.b, 5.c. Area Temperature and Differential Temperature—High

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

Area Temperature—High signals are initiated from thermocouples that are located in the room that is being monitored. Two instruments for each Function monitor each area. Twelve channels for Area Temperature—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. There are four channels for the pump room areas (two per room) and eight channels for the heat exchanger areas (two per room).

Eight thermocouples provide input to the Differential Temperature—High Function. The output of these thermocouples is used to determine the differential temperature. Each channel consists of a differential temperature instrument that receives inputs from thermocouples that are located in the inlet and outlet of the area cooling system for a total of four available channels (two per pump room). Four channels are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. As noted (footnote (d) to Table 3.3.6.1-1), only the inboard trip system is required to be OPERABLE 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. This is allowed since the valve is closed and its operation is administratively controlled to preclude opening the outboard valve when reactor pressure is greater than the RHR cut in permissive pressure.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.a, 5.b, 5.c. Area Temperature and Differential Temperature—High (continued)

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

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

This Function isolates the Group 6 valves.

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

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of some reactor vessel interfaces occurs to begin isolating the potential sources of a break. The Reactor Vessel Water Level—Low, Level 3 Function associated with RHR Shutdown Cooling System isolation is not directly assumed in any transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs. The RHR Shutdown Cooling System isolation on Level 3 supports actions to ensure that the RPV water level does not drop below the top of the active fuel during a vessel draindown event caused by a leak (e.g., pipe break or inadvertent valve opening) in the RHR Shutdown Cooling System.

Reactor Vessel Water Level—Low, Level 3 signals are initiated from differential pressure switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels (two channels per trip system) of the Reactor Vessel Water Level—Low, Level 3 Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. As noted (footnote (d) to Table 3.3.6.1-1), only the inboard trip system is required to be OPERABLE 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. This is allowed since the valve is closed and its

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.d. Reactor Vessel Water Level—Low, Level 3 (continued)

operation is administratively controlled to preclude opening the outboard valve when reactor pressure is greater than the RHR cut in permissive pressure. Also as noted (footnote (e) to Table 3.3.6.1-1), only one trip system is required to be OPERABLE in MODES 4 and 5 provided the RHR Shutdown Cooling System integrity is maintained. System integrity is maintained provided the piping is intact and no maintenance is being performed that has the potential for draining the reactor vessel through the system.

The Reactor Vessel Water Level—Low, Level 3 Function is only required to be OPERABLE in MODES 3, 4, and 5 to prevent this potential flow path from lowering reactor vessel level to the top of the fuel. In MODES 1 and 2, the Reactor Vessel Pressure—High Function and administrative controls ensure that this flow path remains isolated to prevent unexpected loss of inventory via this flow path.

The Reactor Vessel Water Level—Low, Level 3 Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level—Low, Level 3 Allowable Value (LCO 3.3.1.1) since the capability to cool the fuel may be threatened.

This Function isolates the Group 6 valves.

5.e. Reactor Vessel Pressure—High

The Shutdown Cooling System Reactor Vessel Pressure—High Function is provided to isolate the shutdown cooling portion of the RHR System. This interlock is provided only for equipment protection to prevent an intersystem LOCA scenario and credit for the interlock is not assumed in the accident or transient analysis in the FSAR.

The Reactor Steam Dome—High pressure signals are initiated from four pressure switches. Four channels of Reactor Steam Dome Pressure—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. As noted (footnote (d) to Table 3.3.6.1-1), only the inboard trip system is required to be OPERABLE in MODES 1, 2, and 3, as applicable, when the outboard valve control is transferred to the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.e. Reactor Vessel Pressure—High (continued)

alternate remote shutdown panel and the outboard valve is closed. This is allowed since the valve is closed and its operation is administratively controlled to preclude opening the outboard valve when reactor pressure is greater than the RHR cut in permissive pressure.

The Allowable Value was chosen to be low enough to protect the system equipment from overpressurization.

This Function isolates the Group 6 valves.

5.f. Manual Initiation

The Manual Initiation switch and push button channels introduce signals into the RHR Shutdown Cooling System isolation logic that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific FSAR safety analysis that takes credit for this Function. It is retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There are two switch and push buttons (with two channels per switch and push button) for the logic, one switch and push button per trip system. Four channels of the Manual Initiation Function are available and are required to be OPERABLE in MODES 1, 2, and 3 since these are the MODES in which the RHR Shutdown Cooling System Isolation automatic Functions are required to be OPERABLE. While certain automatic Functions are required in MODES 4 and 5, the Manual Initiation Function is not required in MODES 4 and 5, since there are other means (i.e., means other than the Manual Initiation switch and push buttons) to manually isolate the RHR Shutdown Cooling System from the control room. As noted (footnote (d) to Table 3.3.6.1-1), only the inboard trip system is required to be OPERABLE 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. This is allowed since the valve is closed and its operation is administratively controlled to preclude opening the outboard valve when reactor pressure is greater than the RHR cut in permissive pressure.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.f. Manual Initiation (continued)

There is no Allowable Value for this Function, since the channels are mechanically actuated based solely on the position of the switch and push buttons.

This Function isolates the Group 6 valves.

ACTIONS

A Note has been provided to modify the ACTIONS related to primary containment isolation 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 primary containment isolation instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable primary containment isolation instrumentation channel.

A.1

Because of the diversity of sensors available to provide isolation signals and the redundancy of the isolation design, an allowable out of service time of 12 hours or 24 hours, depending on the Function (12 hours for those Functions that have channel components common to RPS instrumentation and 24 hours for those Functions that do not have channel components common to RPS instrumentation), has been shown to be acceptable (Refs. 10 and 11) to permit restoration of any inoperable channel to OPERABLE status. This out of service time is only acceptable provided the associated Function is still maintaining isolation capability (refer to Required Action B.1 Bases). 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

(continued)

BASES

ACTIONS

A.1 (continued)

accommodate a single failure, and allow operation to continue with no further restrictions. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an isolation), Condition C must be entered and its Required Action taken.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in redundant automatic isolation capability being lost for the associated penetration flow path(s). The MSIV portions of the MSL isolation Functions are considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip such that both trip systems will generate a trip signal from the given Function on a valid signal. The other isolation Functions and the MSL drain valves portion of the MSL isolation Functions are considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip such that one trip system will generate a trip signal from the given Function on a valid signal. This ensures that one of the two PCIVs in the associated penetration flow path can receive an isolation signal from the given Function. For Functions 1.a, 1.b, 1.d, 1.e, and 1.f, this would require both trip systems to have one channel OPERABLE or in trip. For Function 1.c, this would require both trip systems to have one channel, associated with each MSL, OPERABLE or in trip. For Functions 2.a, 2.b, 2.c, 2.d, 3.c, 3.d, 4.j, and 5.d, this would require one trip system to have two channels, each OPERABLE or in trip. For Functions 3.a, 3.b, 3.e, 3.f, 3.g, 4.a, 4.b, 4.c, 4.d, 4.e, 4.h, 4.k, and 5.e, this would require one trip system to have one channel OPERABLE or in trip. For Functions 4.f, 4.g, 4.i, 5.a, 5.b, and 5.c, each Function consists of channels that monitor several different locations. Therefore, this would require one channel per location to be OPERABLE or in trip (the channels are not required to be in the same trip system). The Condition does not include the Manual Initiation Functions (Functions 1.g, 2.e, 3.h, 4.l, and 5.f), since they are not assumed in any accident or

(continued)

BASES

ACTIONS

B.1 (continued)

transient analysis. Thus, a total loss of manual initiation capability for 24 hours (as allowed by Required Action A.1) is allowed.

The channels in the trip system in the more degraded state should be placed in trip. The decision as to which trip system is in the more degraded state should be based on prudent judgment and current plant conditions (i.e., what MODE the plant is in).

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

C.1

Required Action C.1 directs entry into the appropriate Condition referenced in Table 3.3.6.1-1. The applicable Condition specified in Table 3.3.6.1-1 is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed. Each time an inoperable channel has not met any Required Action of Condition A or B and the associated Completion Time has expired, Condition C will be entered for that channel and provides for transfer to the appropriate subsequent Condition.

D.1, D.2.1, and D.2.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the associated MSLs may be isolated (Required Action D.1), and if allowed (i.e., plant safety analysis allows operation with an MSL isolated), plant operation with the MSL isolated may continue. Isolating the affected MSL accomplishes the safety function of the inoperable channel. This Required Action will generally only be used if a Function 1.c channel is inoperable and untripped. The associated MSL(s) to be isolated are those whose Main Steam Line Flow—High Function channel(s) are inoperable. Alternately, the plant must be

(continued)

BASES

ACTIONS

D.1, D.2.1, and D.2.2 (continued)

placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours (Required Actions D.2.1 and D.2.2). The 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

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant in at least MODE 2 within 6 hours.

The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

F.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, plant operation may continue if the affected penetration flow path(s) is isolated. Isolating the affected penetration flow path(s) accomplishes the safety function of the inoperable channel.

For some of the Area Temperature and Differential Temperature Functions, the affected penetration flow path(s) may be considered isolated by isolating only that portion of the system in the associated room monitored by the inoperable channel. That is, if the RWCU pump room A Area Temperature channel is inoperable, the A pump room area can be isolated while allowing continued RWCU operation utilizing the B RWCU pump. For the RWCU Blowdown Flow—High Function, the affected penetration flow path(s) may be considered isolated by isolating only the RWCU blowdown piping.

(continued)

BASES

ACTIONS

F.1 (continued)

Alternatively, if it is not desired to isolate the affected penetration flow path(s) (e.g., as in the case where isolating the penetration flow path(s) could result in a reactor scram), Condition H must be entered and its Required Actions taken.

The Completion Time is acceptable because it minimizes risk while allowing sufficient time for plant operations personnel to isolate the affected penetration flow path(s).

G.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, plant operations may continue if the affected penetration flow path(s) is isolated. Isolating the affected penetration flow path(s) accomplishes the safety function of the inoperable channel. The 24 hour Completion Time is acceptable due to the fact that these Functions (Manual Initiation) are not assumed in any accident or transient analysis in the FSAR. Alternately, if it is not desired to isolate the affected penetration flow path(s) (e.g., as in the case where isolating the penetration flow path(s) could result in a reactor scram), Condition H must be entered and its Required Actions taken.

H.1 and H.2

If the channel is not restored to OPERABLE status or placed in trip, or any Required Action of Condition F or G is not met and the associated Completion Time has expired, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

I.1 and I.2

If the channel is not restored to OPERABLE status within the allowed Completion Time, the associated SLC subsystem is declared inoperable or the RWCU System is isolated. Since this Function is required to ensure that the SLC System performs its intended function, sufficient remedial measures are provided by declaring the associated SLC subsystem inoperable or isolating the RWCU System.

The Completion Time of 1 hour is acceptable because it minimizes risk while allowing sufficient time for personnel to isolate the RWCU System.

J.1 and J.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the associated penetration flow path should be closed. However, if the shutdown cooling function is needed to provide core cooling, these Required Actions allow the penetration flow path to remain unisolated provided action is immediately initiated to restore the channel to OPERABLE status or to isolate the RHR Shutdown Cooling System (i.e., provide alternate decay heat removal capabilities so the penetration flow path can be isolated). Actions must continue until the channel is restored to OPERABLE status or the RHR Shutdown Cooling System is isolated.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each Primary Containment Isolation Instrumentation Function are found in the SRs column of Table 3.3.6.1-1.

The Surveillances are also 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 6 hours provided the associated Function maintains isolation capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Refs. 10 and 11) assumption of the average time required to perform channel Surveillance. That

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the PCIVs will isolate the penetration flow path(s) when necessary.

SR 3.3.6.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the 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 on 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 3.3.6.1.2 and SR 3.3.6.1.3

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1.2 and SR 3.3.6.1.3 (continued)

The 92 day Frequency of SR 3.3.6.1.2 is based on reliability analysis described in References 10 and 11. The 184 day Frequency of SR 3.3.6.1.3 is based on engineering judgment and the reliability of the components.

SR 3.3.6.1.4 and SR 3.3.6.1.5

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 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.

SR 3.3.6.1.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required isolation logic for a specific channel. The system functional testing performed on PCIVs in LCO 3.6.1.3 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 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.

SR 3.3.6.1.7

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. Testing is performed only on channels where the assumed response time does not correspond to the

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1.7 (continued)

diesel generator (DG) start time. For channels assumed to respond within the DG start time, sufficient margin exists in the 15 second start time when compared to the typical channel response time (milliseconds) so as to assure adequate response time without a specific measurement test (Ref. 12). The instrument response times must be added to the PCIV closure times to obtain the ISOLATION SYSTEM RESPONSE TIME. However, failure to meet an ISOLATION SYSTEM RESPONSE TIME due to a PCIV closure time not within limits does not require the associated instrumentation to be declared inoperable; only the PCIV is required to be declared inoperable.

C

ISOLATION SYSTEM RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS. The 24 month test Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience that shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent.

REFERENCES

1. FSAR, Section 6.2.1.1.
2. FSAR, Chapters 15 and 15.F.
3. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
4. FSAR, Section 15.1.3.
5. FSAR, Section 15.6.4.
6. FSAR, Section 15.2.5.
7. FSAR, Section 11.3.2.
8. FSAR, Section 9.3.5.2.
9. 10 CFR 50.62.
10. NEDC-31677-P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," June 1989.

(continued)

BASES

REFERENCES (continued)

11. NEDC-30851-P-A, Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.

12. NEDO-32291-A, "System Analyses for the Elimination of Selected Response Time Testing Requirements," October 1995.

B 3.3 INSTRUMENTATION

B 3.3.6.2 Secondary Containment Isolation Instrumentation

BASES

BACKGROUND

The secondary containment isolation instrumentation automatically initiates closure of appropriate secondary containment isolation valves (SCIVs) and starts the Standby Gas Treatment (SGT) System. The function of these systems, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) (Refs. 1 and 2), such that offsite radiation exposures are maintained within the requirements of 10 CFR 100 that are part of the NRC staff approved licensing basis. Secondary containment isolation and establishment of vacuum with the SGT System within the assumed time limits ensures that fission products that are released during certain operations that take place inside primary containment, when primary containment is not required to be OPERABLE, or that take place outside primary containment are maintained within applicable limits.

The isolation instrumentation includes the sensors, relays, and switches that are necessary to cause initiation of secondary containment isolation. Most channels include electronic equipment (e.g., trip relays) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel outputs a secondary containment isolation signal to the isolation logic. Functional diversity is provided by monitoring a wide range of independent parameters. The input parameters to the isolation logic are (a) reactor vessel water level, (b) drywell pressure, and (c) reactor building vent exhaust plenum radiation. Redundant sensor input signals from each parameter are provided for initiation of isolation parameters. In addition, manual initiation of the logic is provided.

Most Secondary Containment Isolation instrumentation Functions receive input from four channels. The output from these channels are arranged into two two-out-of-two logic trip systems. For the Manual Initiation Function, four channels are required to actuate a trip system (a four-out-of-four logic trip system). In addition to the isolation function, the SGT subsystems are initiated. Each trip system will start one fan in each SGT subsystem, but

(continued)

BASES

BACKGROUND (continued)	will only align one SGT subsystem filter train. Automatically isolated secondary containment penetrations are isolated by two isolation valves. Each trip system initiates isolation of one of the two valves on each penetration so that operation of either trip system isolates the penetrations.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The isolation signals generated by the secondary containment isolation instrumentation are implicitly assumed in the safety analyses of References 1 and 2 to initiate closure of valves and start the SGT System to limit offsite doses.

Refer to LCO 3.6.4.2, "Secondary Containment Isolation Valves (SCIVs)," and LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," Applicable Safety Analyses Bases for more detail of the safety analyses.

The secondary containment isolation instrumentation satisfies Criterion 3 of the NRC Policy Statement (Ref. 3). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

The OPERABILITY of the secondary containment isolation instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions. Each Function must have the required number of OPERABLE channels with their setpoints set within the specified Allowable Values, as shown in Table 3.3.6.2-1. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each Function specified in the Table. Nominal trip setpoints are specified in setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Values between 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., reactor vessel water level), and when the measured output value of

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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 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.

In general, the individual Functions are required to be OPERABLE in the MODES or other specified conditions when SCIVs and the SGT System are required.

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

1. Reactor Vessel Water Level—Low Low, Level 2

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. An isolation of the secondary containment and actuation of the SGT System are initiated in order to minimize the potential of an offsite dose release. The Reactor Vessel Water Level—Low Low, Level 2 Function is one of the Functions assumed to be OPERABLE and capable of providing isolation and initiation signals. The isolation and initiation of systems on Reactor Vessel Water Level—Low Low, Level 2 support actions to ensure that any offsite releases are within the limits calculated in the safety analysis (Ref. 1).

Reactor Vessel Water Level—Low Low, Level 2 signals are initiated from differential pressure switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level—Low Low, Level 2 Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Reactor Vessel Water Level—Low Low, Level 2 (continued)

The Reactor Vessel Water Level—Low Low, Level 2 Allowable Value was chosen to be the same as the High Pressure Core Spray (HPCS)/Reactor Core Isolation Cooling (RCIC) Reactor Vessel Water Level—Low Low, Level 2 Allowable Value (LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation," and LCO 3.3.5.2, "Reactor Core Isolation Cooling (RCIC) System Actuation"), since this could indicate the capability to cool the fuel is being threatened.

The Reactor Vessel Water Level—Low Low, Level 2 Function is required to be OPERABLE in MODES 1, 2, and 3 where considerable energy exists in the Reactor Coolant System (RCS); thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. In MODES 4 and 5, the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these MODES; thus, this Function is not required. In addition, the Function is also required to be OPERABLE during operations with a potential for draining the reactor vessel (OPDRVs) because the capability of isolating potential sources of leakage must be provided to ensure that offsite dose limits are not exceeded if core damage occurs.

2. Drywell Pressure—High

High drywell pressure can indicate a break in the reactor coolant pressure boundary (RCPB). An isolation of the secondary containment and actuation of the SGT System are initiated in order to minimize the potential of an offsite dose release. The isolation on high drywell pressure supports actions to ensure that any offsite releases are within the limits calculated in the safety analysis. However, the Drywell Pressure—High Function associated with isolation is not assumed in any FSAR accident or transient analysis. It is retained for the overall redundancy and diversity of the secondary containment isolation instrumentation as required by the NRC approved licensing basis.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Drywell Pressure—High (continued)

High drywell pressure signals are initiated from pressure switches that sense the pressure in the drywell. Four channels of Drywell—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was chosen to be the same as the RPS Drywell Pressure—High Function Allowable Value (LCO 3.3.1.1) since this is indicative of a loss of coolant accident.

The Drywell Pressure—High Function is required to be OPERABLE in MODES 1, 2, and 3 where considerable energy exists in the RCS; thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. This Function is not required in MODES 4 and 5 because the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these MODES.

3. Reactor Building Vent Exhaust Plenum Radiation—High

High secondary containment exhaust radiation is an indication of possible gross failure of the fuel cladding. The release may have originated from the primary containment due to a break in the RCPB or the refueling floor due to a fuel handling accident. When Reactor Building Vent Exhaust Plenum Radiation—High is detected, secondary containment isolation and actuation of the SGT System are initiated to limit the release of fission products as assumed in the FSAR safety analyses (Ref. 2).

The Reactor Building Vent Exhaust Plenum Radiation—High signals are initiated from radiation detectors that are located in the ventilation exhaust plenum, which is the collection point of all reactor building and refueling floor air flow prior to its exhaust to atmosphere. The signal from each detector is input to an individual monitor whose trip outputs are assigned to an isolation channel. Four channels of Reactor Building Vent Exhaust Plenum Radiation—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Reactor Building Vent Exhaust Plenum Radiation—High (continued)

The Allowable Value is chosen to promptly detect gross failure of the fuel cladding.

The Reactor Building Vent Plenum Exhaust Radiation—High Function is required to be OPERABLE in MODES 1, 2, and 3 where considerable energy exists; thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. In MODES 4 and 5, the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these MODES; thus, this Function is not required. In addition, the Function is required to be OPERABLE during CORE ALTERATIONS, OPDRVs, and movement of irradiated fuel assemblies in the secondary containment because the capability of detecting radiation releases due to fuel failures (due to fuel uncovery or dropped fuel assemblies) must be provided to ensure that offsite dose limits are not exceeded.

4. Manual Initiation

The Manual Initiation switch and push button channels introduce signals into the secondary containment isolation logic that are redundant to the automatic protective instrumentation channels, and provide manual isolation capability. There is no specific FSAR safety analysis that takes credit for this Function. It is retained for the overall redundancy and diversity of the secondary containment isolation instrumentation as required by the NRC approved licensing basis.

There are four switch and push buttons (with two channels per switch and push button) for the logic, two switch and push buttons per trip system. Eight channels of the Manual Initiation Function are available and are required to be OPERABLE in MODES 1, 2, and 3 and during CORE ALTERATIONS, OPDRVs, and movement of irradiated fuel assemblies in the secondary containment, since these are the MODES and other specified conditions in which the Secondary Containment Isolation automatic Functions are required to be OPERABLE.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the switch and push buttons.

(continued)

BASES (continued)

ACTIONS

A Note has been provided to modify the ACTIONS related to secondary containment isolation 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 secondary containment isolation instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable secondary containment isolation instrumentation channel.

A.1

Because of the diversity of sensors available to provide isolation signals and the redundancy of the isolation design, an allowable out of service time of 12 hours or 24 hours, depending on the Function (12 hours for those Functions that have channel components common to RPS instrumentation and 24 hours for those Functions that do not have channel components common to RPS instrumentation), has been shown to be acceptable (Refs. 4 and 5) to permit restoration of any inoperable channel to OPERABLE status. This out of service time is only acceptable provided the associated Function is still maintaining isolation capability (refer to Required Action B.1 Bases). 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 inoperable channel in trip would result in an isolation), Condition C must be entered and its Required Actions taken.

(continued)

BASES

ACTIONS (continued)

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of automatic isolation capability for the associated penetration flow path(s) or a complete loss of automatic initiation capability for the SGT System. A Function is considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip, such that one trip system will generate a trip signal from the given Function on a valid signal. This ensures that one of the two SCIVs in the associated penetration flow path and one SGT subsystem can be initiated on an isolation signal from the given Function. For the Functions with two two-out-of-two logic trip systems (Functions 1, 2, and 3), this would require one trip system to have two channels, each OPERABLE or in trip. The Condition does not include the Manual Initiation Function (Function 4), since it is not assumed in any accident or transient analysis. Thus, a total loss of manual initiation capability for 24 hours (as allowed by Required Action A.1) is allowed.

The channels in the trip system in the more degraded state should be placed in trip. The decision as to which trip system is in the more degraded state should be based on prudent judgment and current plant conditions (i.e., what MODE the plant is in).

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.

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

If any Required Action and associated Completion Time of Condition A or B are not met, the ability to isolate the secondary containment and start the SGT System cannot be ensured. Therefore, further actions must be performed to ensure the ability to maintain the secondary containment function. Isolating the associated valves and starting the associated SGT subsystem (Required Actions C.1.1 and C.2.1) performs the intended function of the instrumentation and allows operations to continue.

(continued)

BASES

ACTIONS

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

Alternatively, declaring the associated SCIVs or SGT subsystem inoperable (Required Actions C.1.2 and C.2.2) is also acceptable since the Required Actions of the respective LCOs (LCO 3.6.4.2 and LCO 3.6.4.3) provide appropriate actions for the inoperable components.

One hour is sufficient for plant operations personnel to establish required plant conditions or to declare the associated components inoperable without challenging plant systems.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each Secondary Containment Isolation instrumentation Function are located in the SRs column of Table 3.3.6.2-1.

The Surveillances are also 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 6 hours, provided the associated Function maintains isolation capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Action(s) taken.

This Note is based on the reliability analysis (Refs. 4 and 5) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the SCIVs will isolate the associated penetration flow paths and the SGT System will initiate when necessary.

SR 3.3.6.2.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the indicated parameter for one instrument channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.2.1 (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 on 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 3.3.6.2.2

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 upon the reliability analysis of References 4 and 5.

SR 3.3.6.2.3

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.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.2.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required isolation logic for a specific channel. The system functional testing, performed on SCIVs and the SGT System in LCO 3.6.4.2 and LCO 3.6.4.3, respectively, 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 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, Sections 15.6.5 and 15.F.6.
2. FSAR, Section 15.7.4.
3. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
4. NEDO-31677-P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.
5. NEDC-30851-P-A, Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.

B 3.3 INSTRUMENTATION

B 3.3.7.1 Control Room Emergency Filtration (CREF) System Instrumentation

BASES

BACKGROUND

The CREF System is designed to provide a radiologically controlled environment to ensure the habitability of the control room for the safety of control room operators under all plant conditions. Two independent CREF subsystems are each capable of fulfilling the stated safety function. Some instrumentation and controls for the CREF System automatically initiate action to pressurize the main control room (MCR) to minimize the consequences of radioactive material in the control room environment. The other instrumentation (Main Control Room Ventilation Monitors) only provide alarm and indication in the control room to assist operators in the administrative control of the valves in the remote air intake plenums.

In the event of a loss of coolant accident (LOCA) signal (Reactor Vessel Water Level—Low Low, Level 2, Drywell Pressure—High, or Reactor Building Vent Exhaust Plenum Radiation—High), the CREF System is automatically started in the pressurization mode. Sufficient outside air is drawn in through two separate remote fresh air intakes to keep the MCR slightly pressurized with respect to the radwaste and turbine buildings. The outside air is then circulated through the charcoal filter. Both intakes are physically remote from all plant structures. Redundant radiation monitors sensing the radiation level at each of the two remote intake headers are provided. The valves in the remote intake can be closed manually if the radiation level at the intake rises above an allowable level. Only one remote intake is closed at one time to maintain control room pressurization through one open remote intake.

The CREF System automatic initiation instrumentation has two trip systems: one trip system initiates one CREF subsystem, while the second trip system initiates the other CREF subsystem (Ref. 1). Each trip system receives input from the automatic initiation Functions listed above. Each of these Functions are arranged in a two-out-of-two logic for each trip system. The channels include electronic equipment (e.g., trip relays) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel outputs a CREF System initiation

(continued)

BASES

BACKGROUND (continued)	signal to the initiation logic. The Main Control Room Ventilation Radiation Monitors only provide alarm and indication. The radiation monitors also include electronic equipment that compares measured input signals to pre-established setpoints. When the setpoint is exceeded, the radiation monitors output relay actuates, which then outputs to an alarm in the control room.
APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	The ability of the CREF System to maintain the habitability of the MCR is explicitly assumed for certain accidents as discussed in the FSAR safety analyses (Refs. 2 and 3). CREF System operation ensures that the radiation exposure of control room personnel, through the duration of any one of the postulated accidents, does not exceed the limits set by GDC 19 of 10 CFR 50, Appendix A. CREF instrumentation satisfies Criterion 3 of the NRC Policy Statement (Ref. 4). The OPERABILITY of the CREF System instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.7.1-1. Each Function must have a required number of OPERABLE channels, with their setpoints within the specified Allowable Values, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Allowable Values are specified for each CREF System Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. These nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint that is 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., reactor vessel water level), 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)	parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for process and all instrument uncertainties, including 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 specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

1. Reactor Vessel Water Level—Low Low, Level 2

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. A low reactor vessel water level could indicate a LOCA, and will automatically initiate the CREF System, since this could be a precursor to a potential radiation release and subsequent radiation exposure to control room personnel.

Reactor Vessel Water Level—Low Low, Level 2 signals are initiated from four differential pressure switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level—Low Low, Level 2 Function are available (two channels per trip system) and are required to be OPERABLE to ensure that no single instrument failure can preclude CREF System initiation. The Allowable Value for the Reactor Vessel Water Level—Low Low, Level 2 is chosen to be the same as the Secondary Containment Isolation Reactor Vessel Water Level—Low Low, Level 2 Allowable Value (LCO 3.3.6.2).

The Reactor Vessel Water Level—Low Low, Level 2 Function is required to be OPERABLE in MODES 1, 2, and 3, and during operations with a potential for draining the reactor vessel (OPDRVs), to ensure that the control room personnel are protected. In MODES 4 and 5, at times other than during OPDRVs, the probability of a vessel draindown event releasing radioactive material into the environment, or of a LOCA, is minimal. Therefore this Function is not required.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2. Drywell Pressure—High

High pressure in the drywell could indicate a break in the reactor coolant pressure boundary (RCPB). A high drywell pressure signal could indicate a LOCA and will automatically initiate the CREF System, since this could be a precursor to a potential radiation release and subsequent radiation exposure to control room personnel.

Drywell Pressure—High signals are initiated from four pressure switches that sense drywell pressure. Four channels of Drywell Pressure—High Function are available. (two channels per trip system) and are required to be OPERABLE to ensure that no single instrument failure can preclude CREF System initiation.

The Drywell Pressure—High Allowable Value was chosen to be the same as the Secondary Containment Isolation Drywell Pressure—High Allowable Value (LCO 3.3.6.2).

The Drywell Pressure—High Function is required to be OPERABLE in MODES 1, 2, and 3 to ensure that control room personnel are protected during a LOCA. In MODES 4 and 5, the Drywell Pressure—High Function is not required since there is insufficient energy in the reactor to pressurize the drywell to the Drywell Pressure—High setpoint.

3. Reactor Building Vent Exhaust Plenum Radiation—High

High secondary containment exhaust radiation is an indication of possible gross failure of the fuel cladding. The release may have originated from the primary containment due to a break in the RCPB or the refueling floor due to a fuel handling accident. When Reactor Building Vent Exhaust Plenum Radiation—High is detected, the CREF System is automatically initiated since this radiation release could result in radiation exposure to control room personnel.

Reactor Building Vent Exhaust Plenum Radiation—High signals are initiated from four radiation monitors that measure radiation in the reactor building vent. Four channels of Reactor Building Vent Exhaust Plenum Radiation—High Function are available (two channels per trip system) and are required to be OPERABLE to ensure that no single instrument failure can preclude CREF System initiation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Reactor Building Vent Exhaust Plenum Radiation—High (continued)

The Reactor Building Vent Exhaust Plenum Radiation—High Allowable Value was chosen to be the same as the Secondary Containment Isolation Reactor Building Vent Exhaust Plenum Radiation—High Allowable Value (LCO 3.3.6.2).

The Reactor Building Vent Exhaust Plenum Radiation—High Function is required to be OPERABLE in MODES 1, 2, and 3 to ensure that control room personnel are protected during a LOCA. The Function is also required to be OPERABLE during CORE ALTERATIONS, OPDRVs, and movement of irradiated fuel assemblies in the secondary containment in case of fuel uncovery or a fuel handling accident that could cause a radioactive release to the environment.

4. Main Control Room Ventilation Radiation Monitor

The Main Control Room Ventilation Radiation Monitor measures radiation levels at the remote air intake plenums. A high radiation level may pose a threat to MCR personnel; thus a detector indicating this condition automatically initiates an alarm to alert MCR personnel.

Main Control Room Ventilation Radiation Monitor signals are initiated from four radiation monitors that measure radiation in the control room ventilation remote intake plenums. Four channels of Main Control Room Ventilation Radiation Monitor Function are available (two channels per remote intake plenum) and are required to be OPERABLE to alarm operators as to which Main Control Room Ventilation remote intake is in the potential radioactive plume generated from a design basis LOCA.

The Allowable Value as selected to ensure protection of the MCR personnel.

The Main Control Room Ventilation Radiation Monitor Function is required to be OPERABLE in MODES 1, 2, and 3 to ensure that control room personnel are protected during a LOCA. The Function is also required to be OPERABLE during CORE ALTERATIONS, OPDRVs, and movement of irradiated fuel assemblies in the secondary containment in case of fuel uncovery or a fuel handling accident that could cause a radioactive release to the environment.

(continued)

BASES (continued)

ACTIONS

A Note has been provided to modify the ACTIONS related to CREF System 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 CREF System instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable CREF System instrumentation channel.

A.1

Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.7.1-1. The applicable Condition specified in the Table is Function dependent. Each time an inoperable channel is discovered, Condition A is entered for that channel and provides for transfer to the appropriate subsequent Condition.

B.1 and B.2

Because of the diversity of sensors available to provide initiation signals and the redundancy of the CREF System design, an allowable out of service time of 24 hours has been shown to be acceptable (Refs. 5 and 6) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Function is still maintaining CREF System initiation capability. A Function is considered to be maintaining CREF System initiation capability when sufficient channels are OPERABLE or in trip, such that one trip system will generate an initiation signal from the given Function on a valid signal. This would require one trip system to have two channels, each OPERABLE or in trip. In this situation (loss of CREF System initiation capability), the 24 hour allowance of Required Action B.2 is not appropriate. If the Function is not maintaining CREF

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

System initiation capability, the CREF System must be declared inoperable within 1 hour of discovery of loss of CREF System initiation capability in both trip systems (Required Action B.1). This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action B.1, the Completion Time only begins upon discovery that the CREF System cannot be automatically initiated due to inoperable, untripped channels in the same Function in both trip systems. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoring or tripping of channels.

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 B.2. 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 inoperable channel in trip would result in an initiation), Condition D must be entered and its Required Actions taken.

C.1 and C.2

Because of the diversity of sensors available to provide initiation signals and the redundancy of the CREF System design, an allowable out of service time of 12 hours has been shown to be acceptable (Refs. 5 and 7) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Function is still maintaining CREF System initiation capability. A Function is considered to be maintaining CREF System initiation capability when sufficient channels are OPERABLE or in trip, such that one trip system will generate an initiation signal from the given Function on a valid signal. This would require one trip system to have two channels, each OPERABLE or in trip. In this situation (loss of CREF System initiation capability), the 12 hour allowance of Required Action C.2 is not appropriate. If the Function is not maintaining CREF System initiation capability, the CREF System must be

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

declared inoperable within 1 hour of discovery of loss of CREF System initiation capability in both trip systems (Required Action C.1). This Completion time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action C.1, the Completion Time only begins upon discovery that the CREF System cannot be automatically initiated due to inoperable, untripped Drywell Pressure—High channels in both trip systems. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoring or tripping of channels.

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 C.2. 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 inoperable channel in trip would result in an initiation), Condition D must be entered and its Required Actions taken.

D.1 and D.2

With any Required Action and associated Completion Time of Condition B, C, or D not met, the associated CREF subsystem must be placed in the pressurization mode of operation (Required Action D.1) to ensure that control room personnel will be protected in the event of a Design Basis Accident. The method used to place the CREF subsystem in operation must provide for automatically reinitiating the subsystem upon restoration of power following a loss of power to the CREF subsystem(s). Alternately, if it is not desired to start the subsystem, the CREF subsystem associated with inoperable, untripped channels must be declared inoperable within 1 hour.

The 1 hour Completion Time is intended to allow the operator time to place the CREF subsystem in operation. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels, or for placing the associated CREF subsystem in operation.

(continued)

BASES

ACTIONS (continued)

E.1 and E.2

Because of the diversity of sensors available to provide radiation monitoring signals and the redundancy of the CREF System design, an allowable out of service time of 30 days has been provided to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided: a. the radiation monitoring capability is maintained for the associated remote air intake; and b. both channels associated with the other remote air intake are OPERABLE.

Radiation monitoring capability for a remote air intake is considered to be maintained when sufficient channels are OPERABLE to monitor the radiation at the remote air intake. This would require one channel to be OPERABLE at the remote air intake. In this situation (loss of radiation monitoring in a remote air intake), the 30 day allowance of Required Action E.2 is not appropriate without additional compensating actions. If radiation monitoring capability is not maintained at the associated remote air intake, the remote air intake must also be isolated within 1 hour of discovery of loss of radiation monitoring capability at the remote air intake (Required Action E.1). This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action E.1, the Completion Time only begins upon discovery that both Main Control Room Ventilation Radiation Monitors on one remote air intake are inoperable. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoring of channels or isolating the remote air intake. If it is not desired to isolate the remote air intake (e.g., as in the case where the other remote air intake is already isolated), Condition F must be entered and its Required Actions taken. In addition pursuant to LCO 3.0.6, the CREF System ACTIONS would not be entered even if both remote air intakes were isolated. Therefore, Required Action E.1 is modified by a Note to indicate that when both remote air intakes are isolated (due to complying with the Required Action E.1), ACTIONS for LCO 3.7.3, "Control Room Emergency Filtration (CREF) System," must be immediately entered. This allows Condition E to provide requirements for loss of one or more radiation monitoring channels without regard to whether both remote air intakes are isolated. LCO 3.7.3 provides the appropriate restrictions for both remote air intakes isolated.

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

With one or both channels associated with the other remote air intake inoperable, the 30 day allowance of Required Action E.2 is also not appropriate. In this situation (channels associated with both remote air intakes inoperable), there is a potential that a single failure can result in loss of radiation monitoring capability for both remote air intakes. Therefore, an allowable out of service time of 7 days from discovery of inoperable channels associated with both remote air intakes has been provided to restore all channels associated with one remote air intake to OPERABLE status. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For the first Completion Time of Required Action E.2, the Completion Time only begins upon discovery that one or more Main Control Room Ventilation Radiation Monitors on both remote air intakes are inoperable. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and is consistent with the time provided in the CREF System ACTIONS when one subsystem is inoperable (the monitors could be in a condition susceptible to a single failure that results in a loss of CREF System function, similar to when one subsystem is inoperable).

A Note has also been added to Required Actions E.1 and E.2 to exclude the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require plant shutdown. This exception is acceptable due to the passive function of the instruments, the operator's ability to use alternate means to monitor radiation at the remote air intakes, and the low probability of an event requiring these monitors.

F.1

With any Required Action and associated Completion Time of Condition E not met, the radiation monitoring capability for one or both remote air intakes may be lost, therefore both CREF subsystems must be declared inoperable immediately.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each CREF System instrumentation Function are located in the SRs column of Table 3.3.7.1-1.

The Surveillances are also 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 6 hours, provided the associated Function maintains CREF System initiation or radiation monitoring capability, as applicable. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Refs. 5, 6, and 7) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the CREF System will initiate when necessary.

SR 3.3.7.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the indicated parameter for one instrument channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.1.1 (continued)

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 channels required by the LCO.

SR 3.3.7.1.2

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 References 5, 6, and 7.

SR 3.3.7.1.3

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.

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

SR 3.3.7.1.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.7.3, "Control Room Emergency Filtration (CREF) System," overlaps this Surveillance to provide complete testing of the assumed safety function.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.1.4 (continued)

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 7.3.1.1.7.
2. FSAR, Section 6.4.
3. FSAR, Chapter 15.
4. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
5. GENE-770-06-1-A, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," December 1992.
6. NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.
7. NEDC-30851P-A, Supplement 2, "Technical Specification Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.

B 3.3 INSTRUMENTATION

B 3.3.8.1 Loss of Power (LOP) Instrumentation

BASES

BACKGROUND

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power sources for energizing the various components such as pump motors, motor operated valves, and the associated control components. The LOP instrumentation monitors the 4.16 kV emergency buses. Offsite power is the preferred source of power for the 4.16 kV emergency buses. If the monitors determine that insufficient power is available, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources.

Each 4.16 kV emergency bus has its own independent LOP instrumentation and associated trip logic. The voltage for the Division 1, 2, and 3 buses is monitored at two levels, which can be considered as two different undervoltage functions: loss of voltage and degraded voltage.

The Division 1 and 2 TR-S Loss of Voltage and the Division 3 Loss of Voltage Functions are monitored by two instruments per bus whose output trip contacts are arranged in a one-out-of-two logic configuration per bus. The Division 1 and 2 TR-B Loss of Voltage Function is monitored by one instrument per bus where output trip contacts are arranged in a one-out-of-one logic configuration per bus. The Degraded Voltage Function for Division 1 and 2 4.16 kV Engineered Safety Feature (ESF) buses is monitored by three instruments per bus whose output trip contacts are arranged in a two-out-of-three logic configuration per bus. The Degraded Voltage Function for the Division 3 4.16 kV ESF bus is monitored by two instruments whose output trip contacts are arranged in a two-out-of-two logic configuration (Ref. 1).

Upon a TR-S loss of voltage signal on the Division 1 and 2 4.16 kV ESF buses, the associated DG is started and a three second timer is initiated to allow time to verify loss of voltage and to establish the TR-S source of power. At the end of the three second timer, if bus voltage is still below the setpoint (as sensed by one of the two channels), the Division 1 and 2 1E bus breakers for TR-N1 and TR-S are tripped, the bus ESF loads are shed (except for the 480 V

(continued)

BASES

BACKGROUND (continued)

buses) and an additional timer is initiated (a one second timer). After the one second time delay an attempt is made to close the TR-B breaker if the backup source is available. These two timers constitute the Division 1 and 2 TR-S Loss of Voltage—Time Delay Function. In addition, at the end of the three second timer, a third timer is initiated that inhibits the DG breakers close signal for four seconds. This provides enough time for the 4.16 kV ESF buses to connect to the backup source if it is available. After the four second delay the DG breaker is allowed to close (if the TR-B breaker did not close) once the DG attains the proper frequency and voltage. This timer is not considered part of the LOP Instrumentation (it is tested in LCO 3.8.1, "AC Sources—Operating," and LCO 3.8.2, "AC Sources—Shutdown"). 1C

Upon a TR-B loss of voltage signal on the Division 1 and 2 4.16 kV ESF buses while these buses are tied to TR-B, a 3.5 second timer is initiated to allow time to verify loss of voltage and to establish the TR-B source of power. At the end of the 3.5 second timer, if bus voltage is still below the setpoint, the Division 1 and 2 1E bus breakers for TR-B are tripped. This timer constitutes the Division 1 and 2 TR-B Loss of Voltage—Time Delay Function. The associated DG is started and the bus ESF loads are shed (except the 480 V buses) by the TR-S Loss of Voltage Function, as described earlier.

Upon a loss of voltage signal on the Division 3 4.16 kV ESF bus, a two second timer starts to allow recovery time for the failing source. At the end of the two second time delay the preferred source breaker is tripped if bus voltage is still below the setpoint (as sensed by one of the two channels). This timer constitutes the Division 3 Loss of Voltage—Time Delay Function. In addition, at the end of the two second time delay, a one second timer is initiated. At the end of the one second timer the HPCS DG is started and the DG breaker closes as the DG reaches rated frequency. This timer is not considered part of the LOP Instrumentation (it is tested in LCO 3.8.1 and LCO 3.8.2).

Upon degraded voltage on Division 1, 2, or 3 4.16 kV ESF buses there is an eight second time delay before any action is taken to allow the degraded condition to recover. The Division 1 and 2 eight second time delay is further divided into a primary time delay of five seconds and a secondary time delay of 3 seconds. There are two primary time delay relays, but only one secondary time delay relay. The

(continued)

BASES

BACKGROUND (continued)

secondary time delay relay is started when both degraded voltage relays are tripped and their respective primary time delays have timed out. After the eight second time delay the feeder breakers connecting the sources to the respective 4.16 kV ESF buses are tripped. The actions for Division 1 and 2 at this point during the degraded voltage condition are the same (utilizes the same timers) as the loss of voltage condition for Division 1 and 2 except the first three second timer is bypassed. The actions for Division 3 at this point during the degraded voltage condition are the same (utilizes the same timers) as the loss of voltage condition for Division 3 except the first two second timer is bypassed.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The LOP instrumentation is required for the Engineered Safety Features to function in any accident with a loss of offsite power. The required channels of LOP instrumentation ensure that the ECCS and other assumed systems powered from the DGs provide plant protection in the event of any of the analyzed accidents in References 2, 3, and 4 in which a loss of offsite power is assumed. The initiation of the DGs on loss of offsite power, and subsequent initiation of the ECCS, ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Accident analyses credit the loading of two of the three DGs (i.e., the DG function) based on the loss of offsite power during a loss of coolant accident (LOCA). The diesel starting and loading times have been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power.

The LOP instrumentation satisfies Criterion 3 of the NRC Policy Statement (Ref. 5).

The OPERABILITY of the LOP instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.8.1-1. Each Function must have a required number of OPERABLE channels per 4.16 kV emergency bus, with their setpoints within the specified Allowable Values. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

The Allowable Values are specified for each Function in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

that the setpoint does not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within the 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., degraded voltage), and when the measured output value of the process parameter exceeds the setpoint, the associated device 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 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. Some functions have both an upper and lower analytic limit that must be evaluated. The Allowable Values and the trip setpoints are derived from both an upper and lower analytic limit using the methodology described above. Due to the upper and lower analytic limits, Allowable Values of these Functions appear to incorporate a range. However, the upper and lower Allowable Values are unique, with each Allowable Value associated with one unique analytic limit and trip setpoint.

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

4.16 kV Emergency Bus Undervoltage

1.a, 1.b, 1.c, 1.d, 2.a, 2.b. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)

Loss of voltage on a 4.16 kV emergency bus indicates that offsite power may be completely lost to the respective emergency bus and is unable to supply sufficient power for proper operation of the applicable equipment. Therefore, the power supply to the bus is transferred from offsite power to DG power when the voltage on the bus drops below

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.a, 1.b, 1.c, 1.d, 2.a, 2.b. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) (continued)

the Loss of Voltage Function Allowable Values (loss of voltage with a short time delay). This ensures that adequate power will be available to the required equipment.

The Bus Undervoltage Allowable Values are low enough to prevent inadvertent power supply transfer, but high enough to ensure power is available to the required 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 power is available to the required equipment.

Two channels of Division 1 and 2 TR-S and Division 3 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) Function and Time Delay Function per associated emergency bus are available and are required to be OPERABLE when the associated DG is required to be OPERABLE. One channel of Division 1 and 2 TR-B 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) Function and Time Delay Function per associated emergency bus is available and is required to be OPERABLE when the associated DG is required to be OPERABLE. Refer to LCO 3.8.1, and LCO 3.8.2, for Applicability Bases for the DGs.

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

A reduced voltage condition on a 4.16 kV emergency bus indicates that while offsite power may not be completely lost to the respective emergency bus, power may be insufficient for starting large motors without risking damage to the motors that could disable the ECCS function. Therefore, power supply to the bus is transferred from offsite power to onsite DG power when the voltage on the bus drops below the Degraded Voltage Function Allowable Values (degraded voltage with a time delay). This ensures that adequate power will be available to the required equipment.

The Bus Undervoltage Allowable Values are low enough to prevent inadvertent power supply transfer, but high enough to ensure that sufficient power is available to the required equipment. The Time Delay Allowable Values are long enough

(continued)

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)

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

(continued)

BASES

ACTIONS (continued)

A.1

Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.8.1-1. The applicable Condition specified in the Table is Function dependent. Each time a channel is discovered to be inoperable, Condition A is entered for that channel and provides for transfer to the appropriate subsequent Condition.

B.1 and B.2

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within the same Function result in loss of voltage initiation capability being lost for a DG. Initiation capability is lost if a) both Function 1.a channels for a division are inoperable, b) both Function 1.b channels for a division are inoperable, c) both Function 2.a channels are inoperable, or d) both Function 2.b channels are inoperable. In this situation (loss of initiation capability for a division), the 24 hour allowance of Required Action B.2 is not appropriate and the DG associated with the inoperable channels must be declared inoperable within 1 hour. This ensures that the proper loss of initiation capability check is performed.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." The Completion Time only begins upon discovery that a DG cannot be automatically initiated due to inoperable channels within the Function as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

Because of the redundancy of sensors available to provide initiation signals and the redundancy of the onsite AC power source design, an allowable out of service time of 24 hours is provided to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition D must be entered and its Required

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

Action taken. The Required Actions do not allow placing the channel in trip since this action would cause the initiation.

C.1

With one or more channels of a Function inoperable, the Function is not 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 C.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 D 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.

D.1, D.2.1, and D.2.2

If any Required Action and associated Completion Time of Condition B or C 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 D.1). 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 D.2.1) and the associated offsite circuit declared inoperable immediately (Required

(continued)

BASES

ACTIONS

D.1, D.2.1, and D.2.2 (continued)

Action D.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.

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.

(continued)

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.

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.

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).

B 3.3 INSTRUMENTATION

B 3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

BASES

BACKGROUND

The RPS Electric Power Monitoring System is provided to isolate the RPS bus from the motor generator (MG) set or an alternate power supply in the event of overvoltage, undervoltage, or underfrequency. This system protects the loads connected to the RPS bus against unacceptable voltage and frequency conditions (Ref. 1) and forms an important part of the primary success path for the essential safety circuits. Some of the essential equipment powered from the RPS buses includes the RPS logic, scram solenoids, and various valve isolation logic.

The RPS Electric Power Monitoring assembly will detect any abnormal high or low voltage or low frequency condition in the outputs of the two MG sets or the alternate power supply and will de-energize its respective RPS bus, thereby causing all safety functions normally powered by this bus to de-energize.

In the event of failure of an RPS Electric Power Monitoring System (e.g., both inseries electric power monitoring assemblies), the RPS loads may experience significant effects from the unregulated power supply. Deviation from the nominal conditions can potentially cause damage to the scram solenoids and other Class 1E devices.

In the event of a low voltage condition for an extended period of time, the scram solenoids can chatter and potentially lose their pneumatic control capability, resulting in a loss of primary scram action.

In the event of an overvoltage condition the RPS logic relays and scram solenoids, as well as the main steam isolation valve solenoids, may experience a voltage higher than their design voltage. If the overvoltage condition persists for an extended time period, it may cause equipment degradation and the loss of plant safety function.

Two redundant Class 1E circuit breakers are connected in series between each RPS bus and its MG set, and between each RPS bus and its alternate power supply. Each of these circuit breakers has an associated independent set of

(continued)

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. B 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 ≥ 57 Hz, 120 V ± 10% (to all equipment), and 115 V ± 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

(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 1C

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 3.3.8.2.3 1C

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 3.3.8.2.3 (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."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 Recirculation Loops Operating

BASES

BACKGROUND

The Reactor Recirculation (RRC) System is designed to provide a forced coolant flow through the core to remove heat from the fuel. The forced coolant flow removes heat at a faster rate from the fuel than would be possible with just natural circulation. The forced flow, therefore, allows operation at significantly higher power than would otherwise be possible. The RRC system also controls reactivity over a wide span of reactor power by varying the recirculation flow rate to control the void content of the moderator. The RRC System consists of two recirculation pump loops external to the reactor vessel. These loops provide the piping path for the driving flow of water to the reactor vessel jet pumps. Each external loop contains one variable speed motor driven recirculation pump, a two channel adjustable speed drive (ASD) unit to control pump speed, and associated piping, jet pumps, valves, and instrumentation. The recirculation loops are part of the reactor coolant pressure boundary and are located inside the drywell structure. The jet pumps are reactor vessel internals. C

The recirculated coolant consists of saturated water from the steam separators and dryers that has been subcooled by incoming feedwater. This water passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high pressure flow into an external manifold, from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the driven flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the driving flow. The drive flow and driven flow are mixed in the jet pump throat section and result in partial pressure recovery. The total flow then passes through the jet pump diffuser section into the area below the core (lower plenum), gaining sufficient head in the process to drive the required flow upward through the core.

(continued)

BASES

BACKGROUND (continued)

The subcooled water enters the bottom of the fuel channels and contacts the fuel cladding, where heat is transferred to the coolant. As it rises, the coolant begins to boil, creating steam voids within the fuel channel that continue until the coolant exits the core. Because of reduced moderation, the steam voiding introduces negative reactivity that must be compensated for to maintain or to increase reactor power. The recirculation flow control allows operators to increase recirculation flow and sweep some of the voids from the fuel channel, overcoming the negative reactivity void effect. Thus, the reason for having variable recirculation flow is to compensate for reactivity effects of boiling over a wide range of power generation (i.e., 65 to 100% RTP) without having to move control rods and disturb desirable flux patterns. In addition, the combination of core flow and THERMAL POWER is normally maintained such that core thermal-hydraulic oscillations do not occur. These oscillations can occur during two-loop operation, as well as single-loop and no-loop operation. Plant procedures include requirements of this LCO as well as other vendor and NRC recommended requirements and actions to minimize the potential of core thermal-hydraulic oscillations.

Each recirculation loop is manually started from the control room. The ASD provides regulation of individual recirculation loop drive flows. The flow in each loop is manually controlled. | C

APPLICABLE SAFETY ANALYSES

The operation of the RRC System is an initial condition assumed in the design basis loss of coolant accident (LOCA) (Ref. 1). During a LOCA caused by a recirculation loop pipe break, the intact loop is assumed to provide coolant flow during the first few seconds of the accident. The initial core flow decrease is rapid because the recirculation pump in the broken loop ceases to pump reactor coolant to the vessel almost immediately. The pump in the intact loop coasts down relatively slowly. This pump coastdown governs the core flow response for the next several seconds until the jet pump suction is uncovered (Refs. 2, 3, and 4). The analyses assume that both loops are operating at the same flow prior to the accident. However, the LOCA analysis was reviewed for the case with a flow mismatch between the two loops, with the pipe break assumed to be in the loop with | C

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

the higher flow. While the flow coastdown and core response are potentially more severe in this assumed case (since the intact loop starts at a lower flow rate and the core response is the same as if both loops were operating at a lower flow rate), a small mismatch has been determined to be acceptable (Ref. 4). The recirculation system is also assumed to have sufficient flow coastdown characteristics to maintain fuel thermal margins during abnormal operational transients (Ref. 5), which are analyzed in Chapter 15 of the FSAR.

A plant specific LOCA analysis has been performed assuming only one operating recirculation loop. This analysis has demonstrated that, in the event of a LOCA caused by a pipe break in the operating recirculation loop, the Emergency Core Cooling System response will provide adequate core cooling, provided the APLHGR requirements are modified accordingly (Refs. 3 and 4).

The transient analyses in Chapter 15 of the FSAR have also been performed for single recirculation loop operation (Ref. 6) and demonstrate sufficient flow coastdown characteristics to maintain fuel thermal margins during the abnormal operational transients analyzed provided the MCPR requirements are modified. During single recirculation loop operation, modification to the Reactor Protection System average power range monitor (APRM) instrument setpoints is also required to account for the different relationships between recirculation drive flow and reactor core flow. The APLHGR and MCPR setpoints for single loop operation are specified in the COLR. The APRM flow biased simulated thermal power setpoint is in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation."

Safety analyses performed in Refs. 1, 3, 4, and 7 implicitly assume core conditions are stable. However, at the high power/low flow corner of the operating domain, a small probability of limit cycle neutron flux oscillations exists (Ref. 8) depending on combinations of operating conditions (e.g., power shape, bundle power, and bundle flow).

General Electric Service Information Letter (SIL) No. 380 (Ref. 8) addressed boiling instability and made several recommendations. In this SIL, the power-to-flow map was divided into several regions of varying concern. It also

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BASES

APPLICABLE SAFETY ANALYSES (continued)	discussed the objectives and philosophy of "detect and suppress." The SIL recommends that Region A be bounded by the 100% rod line and Regions B and C be bounded by the 80% rod line.

NRC Generic Letter 86-02 (Ref. 9) discussed both the GE and Siemens stability methodology and stated that due to uncertainties, General Design Criteria 10 and 12 could not be met using available analytical procedures on a BWR. The letter discussed SIL 380 and stated that General Design Criteria 10 and 12 could be met by imposing SIL 380 recommendations in operating regions of potential instabilities. The NRC concluded that regions of potential instability constituted decay ratios of 0.8 and greater by the GE methodology and 0.75 by the Siemens Power Corporation methodology which existed at that time.

Subsequently, a Siemens Power Corporation (SPC) topical report (Ref. 10) was issued which describes an improved stability computer code (STAIF) and was used to establish the current stability boundaries (Regions) for SPC fuel.

The lower boundary of Region A was defined to assure it bounds a decay ratio of 0.9. Therefore, Region A of the power-to-flow map specified in the COLR is bounded by the lower of the 100% rod line and a line that bounds a decay ratio of 0.9. Regions B and C, where applicable, were conservatively defined to bound a decay ratio of 0.75. Therefore, Region C of the power-to-flow map specified in the COLR is bounded only by the 80% rod line, and Region B is bounded by the lower of the 80% rod line and line that bounds a decay ratio of 0.75. In addition, the division between Region B and Region C is at 39% rated core flow. For ABB CENO fuel, the ABB CENO stability analysis methodology and methods (Refs. 11 and 12) are used to confirm the region boundaries described above.

Recirculation loops operating satisfies Criterion 2 of the NRC Policy Statement (Ref. 13).

LCO	Two recirculation loops are normally required to be in operation with their flows matched within the limits specified in SR 3.4.1.1 to ensure that during a LOCA caused by a break of the piping of one recirculation loop the assumptions of the LOCA analysis are satisfied.

(continued)

BASES

LCO (continued)

Alternately, with only one recirculation loop in operation, modifications to the required APLHGR limits (LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"), and MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") must be applied to allow continued operation consistent with the assumptions of Reference 3. In addition, during two-loop and single-loop operation, the combination of core flow and THERMAL POWER must be in the "Unrestricted" Region of the power-to-flow map specified in the COLR to ensure core thermal-hydraulic oscillations do not occur. The "Unrestricted Region" includes any area not shown as "Region A, B, or C" in the power-to-flow map. The full power-to-flow map is not shown to enhance the readability of the bounds of "Regions A, B, and C." | C

APPLICABILITY

In MODES 1 and 2, requirements for operation of the Reactor Coolant Recirculation System are necessary since there is considerable energy in the reactor core and the limiting design basis transients and accidents are assumed to occur.

In MODES 3, 4, and 5, the consequences of an accident are reduced and the coastdown characteristics of the recirculation loops are not important.

ACTIONS

A.1

If the plant is operating in Region A of the power-to-flow map (with any number of recirculation loops in operation), the probability of thermal-hydraulic oscillations is greatly increased. Therefore, action must be taken as soon as practicable to place the reactor mode switch in the shutdown position within 15 minutes.

B.1

With two recirculation loops in operation in Region B or C of the power-to-flow map or with one recirculation loop in operation in Region C of the power-to-flow map, the plant is operating in a region where the potential for thermal-hydraulic oscillations exists. To ensure oscillations are not occurring, the stability monitoring system decay ratio must be verified to be < 0.75 within 15 minutes and every hour thereafter. Stability monitoring is performed utilizing the Advanced Neutron Noise Analysis (ANNA) System.

(continued)

BASES

ACTIONS

B.1 (continued)

The ANNA System is used to monitor average power range monitor (APRM) and local power range monitor (LPRM) signal decay ratio and peak-to-peak noise values when operating in Region B and C of the power-to-flow map. A total of 18 LPRMs, with two LPRMs (levels A and C or levels B and D) per LPRM string in each of the nine core regions, shall be monitored. Four APRMs are also required to be monitored. Both LPRM and APRM signals are required to be monitored to assure that both global (in-phase) and regional (out-of-phase) oscillations can be detected. Decay ratios are calculated from 30 seconds worth of data at a sample rate of 10 samples/second. This sample interval results in some inaccuracy in the decay ratio calculation, but provides rapid update in decay ratio data. The decay ratio limit of 0.75 was selected to provide adequate time for operators to respond such that sufficient margin to an instability occurrence is maintained. The decay ratio limit is not met if the decay ratio of any two or more neutron signals is ≥ 0.75 or if two consecutive decay ratios of any single neutron signal is ≥ 0.75.

The Completion Times of this verification are acceptable for ensuring potential thermal-hydraulic oscillations are detected to allow operator response to suppress the oscillations. These Completion Times were developed considering the operator's inherent knowledge of reactor status and sensitivity to potential thermal-hydraulic instabilities when operating in the associated Regions, and the alarms provided by the ANNA System to alert the operator when near the required decay ratio limit.

C.1

With the Required Action and associated Completion Time of Condition B not met, sufficient margin may not be available for operator response to suppress potential thermal-hydraulic oscillations since the neutron decay ratio is ≥ 0.75. As a result, action must be taken as soon as practicable to restore operation to the "Unrestricted" Region of the power-to-flow map. This can be accomplished by either decreasing THERMAL POWER with control rod insertion or increasing core flow. The starting of a recirculation pump shall not be used as a means to enter the "Unrestricted" Region. The 1 hour Completion Time provides | C

(continued)

BASES

ACTIONS

C.1 (continued)

a reasonable amount of time to complete the Required Action and is considered acceptable based on the alarms and indication provided by the ANNA System to alert the operator to a deteriorating condition.

D.1

With one recirculation loop in operation in Region B of the power-to-flow map, the plant is operating in a region where the potential for thermal-hydraulic oscillations is increased and sufficient margin may not be available for operator response to suppress potential thermal-hydraulic oscillations. As a result, action must be taken as soon as practicable to restore operation to Region C or the "Unrestricted" Region of the power-to-flow map. This can be accomplished by either decreasing THERMAL POWER with control rod insertion or increasing core flow. The starting of a recirculation pump shall not be used as a means to enter the required Regions. The 1 hour Completion Time provides a reasonable amount of time to complete the Required Action and is considered acceptable based on the alarms and indication provided by the ANNA System to alert the operator of a deteriorating condition.

E.1 and F.1

With both recirculation loops operating but the flows not matched, the recirculation loops must be restored to operation within 2 hours. If matched flows are not restored, the recirculation loop with lower flow must be declared "not in operation," as required by Required Action E.1. This Required Action does not require tripping the recirculation pump in the lowest flow loop when the mismatch between total jet pump flows of the two loops is greater than the required limits. However, in cases where large 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 pump speeds to re-establish forward flow or by tripping the pump.

(continued)

BASES

ACTIONS

E.1 and F.1 (continued)

With the requirements of the LCO not met for reasons other than Condition A, B, C, D, or E (e.g., one loop is "not in operation"), the recirculation loops must be restored to operation with matched flows within 4 hours. A recirculation loop is considered not in operation when the pump in that loop is idle or when the mismatch between total jet pump flows of the two loops is greater than required limits for greater than 2 hours (i.e., Required Action E.1 has been taken). Should a LOCA occur with one recirculation loop not in operation, the core flow coastdown and resultant core response may not be bounded by the LOCA analyses. Therefore, only a limited time is allowed to restore the inoperable loop to operating status.

Alternatively, if the single loop requirements of the LCO are applied to operating limits, operation with only one recirculation loop would satisfy the requirements of the LCO and the initial conditions of the accident sequence.

The 2 and 4 hour Completion Times are based on the low probability of an accident occurring during this time period, on a reasonable time to complete the Required Action, and on frequent core monitoring by operators allowing abrupt changes in core flow conditions to be quickly detected.

G.1

With no recirculation loops in operation while in a Region other than Region A of the power-to-flow map, or the Required Action and associated Completion Time of Condition F 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.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

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, 75.95 x 10^6 lbm/hr), 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 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. (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 8, 9, and 10. 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.6.

2. FSAR, Section 6.3.3.7.2.

3. NEDC-32115P, Washington Public Power Supply System Nuclear Project 2, "SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," Revision 2, July 1993.

(continued)

BASES

REFERENCES (continued)

4. CE-NPSD-801-P, "WNP-2 LOCA Analysis Report," May 1996.
5. FSAR, Section 5.4.1.1.
6. CE-NPSD-802-P, "WNP-2 Cycle 12 Transient Analysis Report," May 1996.
7. CE-NPSD-803-P, "WNP-2 Cycle 12 Reload Report," May 1996.
8. GE Service Information Letter No. 380, "BWR Core Thermal Hydraulic Stability," Revision 1, February 10, 1984.
9. NRC Generic Letter 86-02, "Technical Resolution of Generic Issue B-19, Thermal Hydraulic Stability," January 22, 1986.
10. 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.
11. CENPD-294-P-A, "Thermal Hydraulic Stability Methods for Boiling Water Reactors," July 1996.
12. CENPD-295-P-A, "Thermal Hydraulic Stability Methodology for Boiling Water Reactors," July 1996.
13. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 Jet Pumps

BASES

BACKGROUND

The Reactor Recirculation (RRC) System is described in the Background section of the Bases for LCO 3.4.1, "Recirculation Loops Operating," which discusses the operating characteristics of the system and how these characteristics affect the Design Basis Accident (DBA) analyses.

The jet pumps are part of the RRC System and are designed to provide forced circulation through the core to remove heat from the fuel. The jet pumps are located in the annular region between the core shroud and the vessel inner wall. Because the jet pump suction elevation is at two thirds core height, the vessel can be reflooded and coolant level maintained at two thirds core height even with the complete break of the recirculation loop pipe that is located below the jet pump suction elevation.

Each reactor coolant recirculation loop contains 10 jet pumps. Recirculated coolant passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high pressure flow into an external manifold from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the suction flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the drive flow. The drive flow and suction flow are mixed in the jet pump throat section. The total flow then passes through the jet pump diffuser section into the area below the core (lower plenum), gaining sufficient head in the process to drive the required flow upward through the core.

APPLICABLE SAFETY ANALYSES

Jet pump OPERABILITY is an explicit assumption in the design basis loss of coolant accident (LOCA) analysis evaluated in Reference 1.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The capability of reflooding the core to two-thirds core height is dependent upon the structural integrity of the jet pumps. If the structural system, including the beam holding a jet pump in place, fails, jet pump displacement and performance degradation could occur, resulting in an increased flow area through the jet pump and a lower core flooding elevation. This could adversely affect the water level in the core during the reflood phase of a LOCA as well as the assumed blowdown flow during a LOCA.

Jet pumps satisfy Criterion 2 of the NRC Policy Statement (Ref. 2).

LCO

The structural failure of any of the jet pumps could cause significant degradation in the ability of the jet pumps to allow reflooding to two thirds core height during a LOCA. OPERABILITY of all jet pumps is required to ensure that operation of the RRC System will be consistent with the assumptions used in the licensing basis analysis (Ref. 1).

APPLICABILITY

In MODES 1 and 2, the jet pumps are required to be OPERABLE since there is a large amount of energy in the reactor core and since the limiting DBAs are assumed to occur in these MODES. This is consistent with the requirements for operation of the RRC System (LCO 3.4.1).

In MODES 3, 4, and 5, the RRC System is not required to be in operation, and when not in operation sufficient flow is not available to evaluate jet pump OPERABILITY.

ACTIONS

A.1

An inoperable jet pump can increase the blowdown area and reduce the capability to reflood during a design basis LOCA. If one or more of the jet pumps are inoperable, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1 1C

This SR is designed to detect significant degradation in jet pump performance that precedes jet pump failure (Ref. 3). This SR is required to be performed only when the loop has forced recirculation flow since Surveillance checks and measurements can only be performed during jet pump operation. The jet pump failure of concern is a complete mixer displacement due to jet pump beam failure. Jet pump plugging is also of concern since it adds flow resistance to the recirculation loop. Significant degradation is indicated if any two of the three specified criteria confirm unacceptable deviations from established patterns or relationships. The allowable deviations from the established patterns have been developed based on the variations experienced at plants during normal operation and with jet pump assembly failures (Refs. 3 and 4). Since refueling activities (fuel assembly replacement or shuffle, as well as any modifications to fuel support orifice size or core plate bypass flow) can affect the relationship between core flow, jet pump flow, and recirculation loop flow, these relationships may need to be re-established each cycle. Similarly, initial entry into extended single loop operation may also require establishment of these relationships. During the initial weeks of operation under such conditions, while base-lining new "established patterns," engineering judgement of the daily Surveillance results is used to detect significant abnormalities which could indicate a jet pump failure.

The recirculation pump speed operating characteristics (loop flow versus pump speed) are determined by the flow resistance from the loop suction through the jet pump nozzles. A change in the relationship may indicate a flow restriction, loss in pump hydraulic performance, leak, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, the loop flow versus pump speed relationship must be verified. 1C

Total core flow can be determined from measurements of the recirculation loop drive flows. Once this relationship has been established, increased or reduced total core flow for the same recirculation loop drive flow may be an indication of failures in one or several jet pumps.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1 (continued)

Individual jet pumps in a recirculation loop typically do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The flow (or jet pump diffuser to lower plenum differential pressure) pattern or relationship of one jet pump to the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system (Ref. 3). Normal flow ranges and established jet pump flow and differential pressure patterns are established by plotting historical data as discussed in Reference 3.

The 24 hour Frequency has been shown by operating experience to be adequate to verify jet pump OPERABILITY and is consistent with the Frequency for recirculation loop OPERABILITY verification.

This SR is modified by two Notes. Note 1 allows this Surveillance not to be performed until 4 hours after the associated recirculation loop is in operation, since these checks can only be performed during jet pump operation. The 4 hours is an acceptable time to establish conditions appropriate for data collection and evaluation.

Note 2 allows this SR not to be performed until 24 hours after THERMAL POWER exceeds 25% RTP. During low flow conditions, jet pump noise approaches the threshold response of the associated flow instrumentation and precludes the collection of repeatable and meaningful data. The 24 hours is an acceptable time to establish conditions appropriate to perform this SR.

REFERENCES

1. FSAR, Sections 6.3 and 15.F.6.

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

(continued)

BASES

REFERENCES (continued)

3. GE Service Information Letter No. 330, including Supplement 1, "Jet Pump Beam Cracks," June 9, 1980.

4. NUREG/CR-3052, "Closeout of IE Bulletin 80-07: BWR Jet Pump Assembly Failure," November 1984.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 Safety/Relief Valves (SRVs) – ≥ 25% RTP 1C

BASES

BACKGROUND

The American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Ref. 1) requires the Reactor Pressure Vessel be protected from overpressure during upset conditions by self actuated safety valves. As part of the nuclear pressure relief system, the size and number of safety/relief valves (SRVs) are selected such that peak pressure in the nuclear system will not exceed the ASME Code limits for the reactor coolant pressure boundary (RCPB).

The SRVs are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. Each SRV discharges steam through a discharge line to a point below the minimum water level in the suppression pool.

The SRVs can actuate by either of two modes: the safety mode or the relief mode. (However, for the purposes of this LCO, only the safety mode is required). In the safety mode (or spring mode of operation), the direct action of the steam pressure in the main steam lines will act against a spring loaded disk that will pop open when the valve inlet pressure exceeds the spring force. In the relief mode (or power actuated mode of operation), a pneumatic piston/cylinder and mechanical linkage assembly are used to open the valve by overcoming the spring force, even with the valve inlet pressure equal to 0 psig. The pneumatic operator is arranged so that its malfunction will not prevent the valve disk from lifting if steam inlet pressure reaches the spring lift set pressures. In the relief mode, valves may be opened manually or automatically at the selected preset pressure. Seven of the SRVs that provide the safety and relief function are part of the Automatic Depressurization System specified in LCO 3.5.1, "ECCS – Operating."

APPLICABLE SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressure transient. Evaluations have determined that the most severe transient is the closure of all main steam isolation valves (MSIVs) followed by reactor scram on high neutron flux (i.e., failure of the direct scram

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

associated with MSIV position) (Ref. 2). For the purpose of the overpressure protection analysis, 12 of the SRVs with the highest setpoints are assumed to operate in the safety mode. The analysis results demonstrate that the design SRV capacity is capable of maintaining reactor pressure below the ASME Code limit (Ref. 1) of 110% of vessel design pressure (110% x 1250 psig = 1375 psig). This LCO helps to ensure that the acceptance limit of 1375 psig is met during the most severe pressure transient.

From an overpressure standpoint, the design basis events are bounded by the MSIV closure with flux scram event described above. References 3, 4, 5, and 6 discuss additional events that are expected to actuate the SRVs. The analysis described in Reference 5 also assumes that, for certain events (e.g., ECCS performance during a small break LOCA), of the 12 required OPERABLE SRVs, two SRVs with lift setpoints in the lowest two lift setpoint groups are OPERABLE.

SRVs — ≥ 25% RTP satisfy Criterion 3 of the NRC Policy Statement (Ref. 7).

LCO

The safety function of 12 SRVs is required to be OPERABLE, with two SRVs in the lowest two lift setpoint groups OPERABLE. The requirements of this LCO are applicable only to the capability of the SRVs to mechanically open to relieve excess pressure when the lift setpoint is exceeded (safety mode). In Reference 2, an evaluation was performed to establish the parametric relationship between the peak vessel pressure and the number of OPERABLE SRVs. The results show that with a minimum of 12 SRVs in the safety mode OPERABLE, the ASME Code limit of 1375 psig is not exceeded. While the analysis assumes the overpressurization event is mitigated by SRVs with the highest setpoints (Ref. 2), the small break LOCA analysis (Ref. 5) assumes two of the 12 required OPERABLE SRVs have lift setpoints in the lowest two lift setpoint groups.

The SRV safety setpoints are established to ensure the ASME Code limit on peak reactor pressure is satisfied. The ASME Code specifications require the lowest safety valve be set at or below vessel design pressure (1250 psig) and the highest safety valve be set so the total accumulated pressure does not exceed 110% of the design pressure for overpressurization conditions. The transient evaluations in

(continued)

BASES

LCO (continued)

References 3, 4, 5, and 8 involving the safety mode are based on these setpoints, but also include the additional uncertainties of ± 3% of the nominal setpoint to account for potential setpoint drift to provide an added degree of conservatism.

Operation with fewer valves OPERABLE than specified, or with setpoints outside the ASME limits, could result in a more severe reactor response to a transient than predicted, possibly resulting in the ASME Code limit on reactor pressure being exceeded or unacceptable core thermal margins.

APPLICABILITY

With THERMAL POWER ≥ 25% RTP, the specified number of SRVs must be OPERABLE since there is considerable energy in the reactor core and the limiting design basis transients are assumed to occur. The SRVs may be required to provide pressure relief to limit peak reactor pressure.

The requirements for SRVs in MODE 1 with THERMAL POWER < 25% RTP and in MODES 2 and 3 are discussed in LCO 3.4.4, "SRVs — < 25% RTP." In MODE 4, decay heat is low enough for the RHR System to provide adequate cooling, and reactor pressure is low enough that the overpressure limit is unlikely to be approached by assumed operational transients or accidents. In MODE 5, the reactor vessel head is unbolted or removed and the reactor is at atmospheric pressure. The SRV function is not needed during these conditions.

ACTIONS

A.1

With less than the minimum number of required SRVs OPERABLE, a transient may result in the violation of the ASME Code limit on reactor pressure, or core thermal margins may be challenged. If one or more required SRVs are inoperable, the plant must be brought to a MODE or other specified Condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < 25% RTP within 4 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

This Surveillance demonstrates that the required SRVs will open at the pressures assumed in the safety analysis of Reference 2. The demonstration of the SRV safety function lift settings is in accordance with the Inservice Testing Program. The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures.

SR 3.4.3.2

A manual actuation of each required SRV is performed to verify that, mechanically, the valve is functioning properly and no blockage exists in the valve discharge line. This can be demonstrated by the response of the turbine governor valves or bypass valves, by a change in the measured steam flow, or any other method suitable to verify steam flow. If the valve fails to actuate due only to the failure of the solenoid but is capable of opening on overpressure, the safety function of the SRV is not considered inoperable.

The 24 month Frequency was developed based on the SRV tests required by the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 9). Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.
2. FSAR, Section 15.2.4.
3. FSAR, Chapters 15 and 15.F.
4. GE-NE-187-24-0992, "WPPSS Nuclear Project 2 SRV Setpoint Tolerance and Out-of-Service Analysis," Revision 2, July 1993.
5. NEDC-32115P, Washington Public Power Supply System Nuclear Project 2, "SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," Revision 2, July 1993.

(continued)

BASES

REFERENCES (continued)	6.	CENPD-300-P-A, "Reference Safety Report for Boiling Water Reactor Reload Fuel," July 1996.
	7.	Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
	8.	CE-NPSD-803-P, "WNP-2 Cycle 12 Reload Report," May 1996.
	9.	ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 Safety/Relief Valves (SRVs) — < 25% RTP 1C

BASES

BACKGROUND

A description of the safety/relief valves (SRVs) is provided in the Bases for LCO 3.4.3, "Safety/Relief Valves (SRVs) — ≥ 25% RTP." 1C

APPLICABLE SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressure transient. Evaluations have determined that the most severe transient is the closure of all main steam isolation valves (MSIVs) followed by reactor scram on high neutron flux (i.e., failure of the direct scram associated with MSIV position) (Ref. 1). OPERABILITY of SRVs is normally demonstrated during low power operation since an SRV test facility is not available at WNP-2. Therefore, in order to facilitate testing during power operations, an overpressure transient analysis was performed for the bounding accident at 25% RTP. The analysis assumptions were similar to that in Reference 1; closure of all MSIVs followed by a reactor scram on high neutron flux (i.e., failure of the direct scram associated with MSIV position). For the purpose of the analysis, four of the SRVs with the highest setpoints are assumed to operate in the safety mode (Ref. 2). The analysis results demonstrate that the design SRV capacity is capable of maintaining reactor pressure below the ASME Code limit (Ref. 3) of 110% of vessel design pressure (110% x 1250 psig = 1375 psig). This LCO helps to ensure that the acceptance limit of 1375 psig is met during the most severe pressure transient.

From an overpressure standpoint, these design basis events are bounded by the MSIV closure with flux scram event described above. References 4, 5, and 6 discuss additional events that are expected to actuate the SRVs. 1C

SRVs — < 25% RTP satisfy Criterion 3 of the NRC Policy Statement (Ref 7). 1C

LCO

The safety function of four SRVs is required to be OPERABLE. The requirements of this LCO are applicable only to the capability of the SRVs to mechanically open to relieve excess pressure when the lift setpoint is exceeded (safety mode). In Reference 2, an evaluation was performed to

(continued)

BASES

LCO (continued)

establish the parametric relationship between the peak vessel pressure and the number of OPERABLE SRVs. The results show that with a minimum of four SRVs in the safety mode OPERABLE, the ASME Code limit of 1375 psig is not exceeded. Since the analysis assumes the overpressurization event is mitigated by SRVs with the highest setpoints, any four of the 18 SRVs can be used to meet this LCO.

The SRV safety setpoints are established to ensure the ASME Code limit on peak reactor pressure is satisfied. The ASME Code specifications require the lowest safety valve be set at or below vessel design pressure (1250 psig) and the highest safety valve be set so the total accumulated pressure does not exceed 110% of the design pressure for overpressurization conditions. The transient evaluations in References 4, 5, and 8 involving the safety mode are based on these setpoints, but also include the additional uncertainties of ± 3% of the nominal setpoint to account for potential setpoint drift to provide an added degree of conservatism. |C

Operation with fewer valves OPERABLE than specified, or with setpoints outside the ASME limits, could result in a more severe reactor response to a transient than predicted, possibly resulting in the ASME Code limit on reactor pressure being exceeded.

APPLICABILITY

In MODE 1 with THERMAL POWER < 25% RTP and MODES 2 and 3, the specified number of SRVs must be OPERABLE since there may be considerable energy in the reactor core and the limiting design basis transients are assumed to occur. The SRVs may be required to limit peak reactor pressure.

The requirements for SRVs with THERMAL POWER ≥ 25% RTP are discussed in LCO 3.4.3. In MODE 4, decay heat is low enough for the RHR System to provide adequate cooling, and reactor pressure is low enough that the overpressure limit cannot be approached by assumed operational transients or accidents. In MODE 5, the reactor vessel head is unbolted or removed and the reactor is at atmospheric pressure. The SRV function is not needed during these conditions. |C

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

With less than the minimum number of required SRVs OPERABLE, a transient may result in the violation of the ASME Code limit on reactor pressure. If one or more required SRVs are inoperable, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1 1C

This Surveillance demonstrates that the required SRVs will open at the pressures assumed in the safety analysis of Reference 2. The demonstration of the SRV safety function lift settings is in accordance with the Inservice Testing Program. The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures.

SR 3.4.4.2 1C

A manual actuation of each required SRV is performed to verify that, mechanically, the valve is functioning properly and no blockage exists in the valve discharge line. This can be demonstrated by the response of the turbine governor valves or bypass valves, by a change in the measured steam flow, or any other method suitable to verify steam flow. Adequate reactor steam dome pressure must be available to perform this test to avoid damaging the valve. Also, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure and flow when the SRVs divert steam flow upon opening. Sufficient time is therefore allowed after the required pressure and flow are achieved to perform this test. Adequate pressure at which this test is to be performed is 900 psig (consistent with the recommendations of the vendor). Adequate steam flow is represented by THERMAL POWER ≥ 10% RTP. Plant startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements, prior to reactor startup. Therefore, this SR

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.4.2 (continued)

is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for manual actuation after the required pressure and flow are reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SR. If the valve fails to actuate due only to the failure of the solenoid but is capable of opening on overpressure, the safety function of the SRV is not considered inoperable.

The 24 month Frequency was developed based on the SRV tests required by the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 9). Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section 15.2.4.
2. WNP-2 Calculation NE-02-94-66, Revision 0, November 13, 1995.
3. ASME, Boiler and Pressure Vessel Code, Section III.
4. FSAR, Chapters 15 and 15.F.
5. GE-NE-187-24-0992, "WPPSS Nuclear Project.2 SRV Setpoint Tolerance and Out-of-Service Analysis," Revision 2, July 1993.
6. CENPD-300-P-A, "Reference Safety Report for Boiling Water Reactor Reload Fuel," July 1996.
7. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
8. CE-NPSD-803-P, "WNP-2 Cycle 12 Reload Report," May 1996.
9. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Operational LEAKAGE

BASES

BACKGROUND

The RCS includes systems and components that contain or transport the coolant to or from the reactor core. The pressure containing components of the RCS and the portions of connecting systems out to and including the isolation valves define the reactor coolant pressure boundary (RCPB). The joints of the RCPB components are welded or bolted.

During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. Limits on RCS operational LEAKAGE are required to ensure appropriate action is taken before the integrity of the RCPB is impaired. This LCO specifies the types and limits of LEAKAGE. This protects the RCS pressure boundary described in 10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50, Appendix A (Refs. 1, 2, and 3).

The safety significance of leaks from the RCPB varies widely depending on the source, rate, and duration. Therefore, detection of LEAKAGE in the drywell is necessary. Methods for quickly separating the identified LEAKAGE from the unidentified LEAKAGE are necessary to provide the operators quantitative information to permit them to take corrective action should a leak occur detrimental to the safety of the facility or the public.

A limited amount of leakage inside the drywell is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected and isolated from the drywell atmosphere, if possible, so as not to mask RCS operational LEAKAGE detection.

This LCO deals with protection of the RCPB from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The allowable RCS operational LEAKAGE limits are based on the predicted and experimentally observed behavior of pipe cracks. The normally expected background LEAKAGE due to equipment design and the detection capability of the instrumentation for determining system LEAKAGE were also considered. The evidence from experiments suggests, for LEAKAGE even greater than the specified unidentified LEAKAGE limits, the probability is small that the imperfection or crack associated with such LEAKAGE would grow rapidly.

The unidentified LEAKAGE flow limit allows time for corrective action before the RCPB could be significantly compromised. The 5 gpm limit is a small fraction of the calculated flow from a critical crack in the primary system piping. Crack behavior from experimental programs (Refs. 4 and 5) shows leak rates of hundreds of gallons per minute will precede crack instability (Ref. 6).

The low limit on increase in unidentified LEAKAGE assumes a failure mechanism of intergranular stress corrosion cracking (IGSCC) that produces tight cracks. This flow increase limit is capable of providing an early warning of such deterioration.

No applicable safety analysis assumes the total LEAKAGE limit. The total LEAKAGE limit considers RCS inventory makeup capability and drywell floor sump capacity.

RCS operational LEAKAGE satisfies Criterion 2 of the NRC Policy Statement (Ref. 7).

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material degradation. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

(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 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.

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 (continued)

ACTIONS

A.1

With RCS unidentified or total LEAKAGE greater than the limits, actions must be taken to reduce the leak. Because the LEAKAGE limits are conservatively below the LEAKAGE that would constitute a critical crack size, 4 hours is allowed to reduce the LEAKAGE rates before the reactor must be shut down. If an unidentified LEAKAGE has been identified and quantified, it may be reclassified and considered as identified LEAKAGE. However, the total LEAKAGE limit would remain unchanged.

B.1 and B.2

An unidentified LEAKAGE increase of > 2 gpm within a 24 hour period is an indication of a potential flaw in the RCPB and must be quickly evaluated. Although the increase does not necessarily violate the absolute unidentified LEAKAGE limit, certain susceptible components must be determined not to be the source of the LEAKAGE increase within the required Completion Time. For an unidentified LEAKAGE increase greater than required limits, an alternative to reducing LEAKAGE increase to within limits (i.e., reducing the leakage rate such that the current rate is less than the "2 gpm increase in the previous 24 hours" limit; either by isolating the source or other possible methods) is to evaluate RCS type 304 and type 316 austenitic stainless steel piping that is subject to high stress or that contains relatively stagnant or intermittent flow fluids and determine it is not the source of the increased LEAKAGE. This type of piping is very susceptible to IGSCC.

The 4 hour Completion Time is needed to properly reduce the LEAKAGE increase or verify the source before the reactor must be shut down.

C.1 and C.2

If any Required Action and associated Completion Time of Condition A or B is not met or if pressure boundary LEAKAGE exists, 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. The allowed Completion Times are reasonable,

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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 3.4.5.1 1C

The RCS LEAKAGE is monitored by a variety of instruments designed to provide alarms when LEAKAGE is indicated and to quantify the various types of LEAKAGE. Leakage detection instrumentation is discussed in more detail in the Bases for LCO 3.4.7, "RCS Leakage Detection Instrumentation." Sump flow rate is typically monitored to determine actual LEAKAGE rates. However, any method may be used to quantify LEAKAGE within the guidelines of Reference 8. In conjunction with alarms and other administrative controls, a 12 hour Frequency for this Surveillance is appropriate for identifying changes in LEAKAGE and for tracking required trends (Ref. 9). 1C

REFERENCES

1. 10 CFR 50.2.
2. 10 CFR 50.55a(c).
3. 10 CFR 50, Appendix A, GDC 55.
4. GEAP-5620, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flows," April 1968.
5. NUREG-75/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactors," October 1975.
6. FSAR, Section 5.2.5.5.3.
7. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
8. Regulatory Guide 1.45, May 1973.
9. Generic Letter 88-01, Supplement 1, February 1992.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Pressure Isolation Valve (PIV) Leakage 1C

BASES

BACKGROUND

RCS PIVs are defined as any two normally closed valves in series within the reactor coolant pressure boundary (RCPB). The function of RCS PIVs is to separate the high pressure RCS from an attached low pressure system. This protects the RCS pressure boundary described in 10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50, Appendix A (Refs. 1, 2, and 3). PIVs are designed to meet the requirements of Reference 4. During their lives, these valves can produce varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration.

The RCS PIV LCO allows RCS high pressure operation when leakage through these valves exists in amounts that do not compromise safety. The PIV leakage limit applies to each individual valve. Leakage through these valves is not included in any allowable LEAKAGE specified in LCO 3.4.5, "RCS Operational LEAKAGE." 1C

Although this Specification provides a limit on allowable PIV leakage rate, its main purpose is to prevent overpressure failure of the low pressure portions of connecting systems. The leakage limit is an indication that the PIVs between the RCS and the connecting systems are degraded or degrading. PIV leakage could lead to overpressure of the low pressure piping or components. Failure consequences could be a loss of coolant accident (LOCA) outside of containment, an unanalyzed accident which could degrade the ability for low pressure injection.

A study (Ref. 5) evaluated various PIV configurations to determine the probability of intersystem LOCAs. This study concluded that periodic leakage testing of the PIVs can substantially reduce intersystem LOCA probability.

PIVs are provided to isolate the RCS from the following connected systems:

a. Residual Heat Removal (RHR) System;

b. Low Pressure Core Spray System;

(continued)

BASES

BACKGROUND (continued)

c. High Pressure Core Spray System; and

d. Reactor Core Isolation Cooling System.

The PIVs are listed in Reference 6.

APPLICABLE SAFETY ANALYSES

Reference 5 evaluated various PIV configurations, leakage testing of the valves, and operational changes to determine the effect on the probability of intersystem LOCAs. This study concluded that periodic leakage testing of the PIVs can substantially reduce the probability of an intersystem LOCA.

PIV leakage is not considered in any Design Basis Accident analyses. This Specification provides for monitoring the condition of the RCPB to detect PIV degradation that has the potential to cause a LOCA outside of containment. RCS PIV leakage satisfies Criterion 2 of the NRC Policy Statement (Ref. 7).

LCO

RCS PIV leakage is leakage into closed systems connected to the RCS. Isolation valve leakage is usually on the order of drops per minute. Leakage that increases significantly suggests that something is operationally wrong and corrective action must be taken. Violation of this LCO could result in continued degradation of a PIV, which could lead to overpressurization of a low pressure system and the loss of the integrity of a fission product barrier.

The LCO PIV leakage limit is 0.5 gpm per nominal inch of valve size with a maximum limit of 5 gpm (Ref. 4).

Reference 4 permits leakage testing at a lower pressure differential than between the specified maximum RCS pressure and the normal pressure of the connected system during RCS operation (the maximum pressure differential). The observed rate may be adjusted to the maximum pressure differential by assuming leakage is directly proportional to the pressure differential to the one-half power.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, this LCO applies because the PIV leakage potential is greatest when the RCS is pressurized. In MODE 3, valves in the RHR flowpath are not required to meet the requirements of this LCO when in, or during transition to or from, the RHR shutdown cooling mode of operation.

In MODES 4 and 5, leakage limits are not provided because the lower reactor coolant pressure results in a reduced potential for leakage and for a LOCA outside the containment. Accordingly, the potential for the consequences of reactor coolant leakage is far lower during these MODES.

ACTIONS

The ACTIONS are modified by two Notes. Note 1 has been provided to modify the ACTIONS related to RCS PIV flow paths. 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 the Condition of RCS PIV leakage limits exceeded provide appropriate compensatory measures for separate, affected RCS PIV flow paths. As such, a Note has been provided that allows separate Condition entry for each affected RCS PIV flow path. Note 2 requires an evaluation of affected systems if a PIV is inoperable. The leakage may have affected system OPERABILITY, or isolation of a leaking flow path with an alternate valve may have degraded the ability of the interconnected system to perform its safety function. As a result, the applicable Conditions and Required Actions for systems made inoperable by PIVs must be entered. This ensures appropriate remedial actions are taken, if necessary, for the affected systems.

<u>A.1</u>

If leakage from one or more RCS PIVs is not within limit, the flow path must be isolated by at least one closed manual, de-activated, automatic, or check valve within

(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. 1B

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 3.4.6.1 1C

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 ≥ 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 1B

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1 (continued) 1C

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.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

GDC 30 of 10 CFR 50, Appendix A (Ref. 1), requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems.

Limits on LEAKAGE from the reactor coolant pressure boundary (RCPB) are required so that appropriate action can be taken before the integrity of the RCPB is impaired (Ref. 2). Leakage detection systems for the RCS are provided to alert the operators when leakage rates above normal background levels are detected and also to supply quantitative measurement of rates. The Bases for LCO 3.4.5, "RCS Operational LEAKAGE," discuss the limits on RCS LEAKAGE rates.

Systems for separating the LEAKAGE of an identified source from an unidentified source are necessary to provide prompt and quantitative information to the operators to permit them to take immediate corrective action.

LEAKAGE from the RCPB inside the drywell is detected by at least one of two independently monitored variables, such as sump drain flow changes and drywell gaseous and particulate radioactivity levels. The primary means of quantifying LEAKAGE in the drywell is the drywell floor drain sump flow monitoring system.

The drywell floor drain sump flow monitoring system monitors the LEAKAGE collected in the floor drain sump. This unidentified LEAKAGE consists of LEAKAGE from control rod drives, valve flanges or packings, floor drains, the Reactor Building Closed Cooling Water System, and drywell air cooling unit condensate drains, and any LEAKAGE not collected in the drywell equipment drain sump. The drywell floor drain sump gravity drains to a reactor building floor drain sump. The drywell floor drain sump piping to the reactor building floor drain sump has a transmitter that supplies flow indication in the main control room. If the sump drain flow increases to the high flow alarm setpoint, an alarm sounds in the main control room, indicating a LEAKAGE rate from the sump in excess of a preset limit.

(continued)

BASES

BACKGROUND (continued)	The drywell atmosphere monitoring systems (particulate and gaseous) continuously monitor the drywell atmosphere for airborne particulate and gaseous radioactivity. A sudden increase of radioactivity, which may be attributed to RCPB steam or reactor water LEAKAGE, is annunciated in the control room. The drywell atmosphere particulate and gaseous radioactivity monitoring systems are not capable of quantifying leakage rates, but are sensitive enough to indicate increased LEAKAGE rates of 1 gpm within 1 hour (Ref. 3). Larger changes in LEAKAGE rates are detected in proportionally shorter times.
APPLICABLE SAFETY ANALYSES	A threat of significant compromise to the RCPB exists if the barrier contains a crack that is large enough to propagate rapidly. LEAKAGE rate limits are set low enough to detect the LEAKAGE emitted from a single crack in the RCPB (Refs. 4 and 5). Each of the leakage detection systems inside the drywell is designed with the capability of detecting LEAKAGE less than the established LEAKAGE rate limits and providing appropriate alarm of excess LEAKAGE in the control room. A control room alarm allows the operators to evaluate the significance of the indicated LEAKAGE and, if necessary, shut down the reactor for further investigation and corrective action. The allowed LEAKAGE rates are well below the rates predicted for critical crack sizes (Ref. 6). Therefore, these actions provide adequate response before a significant break in the RCPB can occur. RCS leakage detection instrumentation satisfies Criterion 1 of the NRC Policy Statement (Ref. 7).
LCO	The drywell floor drain sump flow monitoring system is required to quantify the unidentified LEAKAGE from the RCS. The other monitoring systems (particulate or gaseous) provide early alarms to the operators so closer examination of other detection systems will be made to determine the extent of any corrective action that may be required. With the leakage detection systems inoperable, monitoring for LEAKAGE in the RCPB is degraded.
APPLICABILITY	In MODES 1, 2, and 3, leakage detection systems are required to be OPERABLE to support LCO 3.4.5. This Applicability is consistent with that for LCO 3.4.5. 1C

(continued)

BASES (continued)

ACTIONS

A.1

With the drywell floor drain sump flow monitoring system inoperable, no other form of sampling can provide the equivalent information to quantify leakage. However, the drywell atmospheric activity monitor will provide indications of changes in leakage.

With the drywell floor drain sump flow monitoring system inoperable, but with RCS unidentified and total LEAKAGE being determined every 12 hours (SR 3.4.5.1), operation may continue for 30 days. The 30 day Completion Time of Required Action A.1 is acceptable, based on operating experience, considering the multiple forms of leakage detection that are still available. Required Action A.1 is modified by a Note that states that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when the drywell floor drain sump flow monitoring system is inoperable. This allowance is provided because other instrumentation is available to monitor RCS leakage. C

B.1 and B.2

With both gaseous and particulate drywell atmospheric monitoring channels inoperable (i.e., the required drywell atmospheric monitoring system), grab samples of the drywell atmosphere shall be taken and analyzed to provide periodic leakage information. Provided a sample is obtained and analyzed every 12 hours, the plant may be operated for up to 30 days to allow restoration of at least one of the required monitors.

The 12 hour interval provides periodic information that is adequate to detect LEAKAGE. The 30 day Completion Time for restoration recognizes that at least one other form of leakage detection is available.

The Required Actions are modified by a Note that states that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when both the gaseous and particulate primary containment atmospheric monitoring channels are inoperable. This allowance is provided because other instrumentation is available to monitor RCS leakage.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

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

D.1

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

SURVEILLANCE REQUIREMENTS

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 6 hours, provided the other required instrumentation (either the drywell floor drain sump flow monitoring system or the drywell atmospheric monitoring channel, as applicable) is OPERABLE. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. The 6 hour testing allowance is acceptable since it does not significantly reduce the probability of properly monitoring drywell leakage.

SR 3.4.7.1 1C

This SR requires the performance of a CHANNEL CHECK of the required drywell atmospheric monitoring system. The check gives reasonable confidence that the channel is operating properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.2 |C

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 3.4.7.3 |C

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).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 RCS Specific Activity 1C

BASES

BACKGROUND

During circulation, the reactor coolant acquires radioactive materials due to release of fission products from fuel leaks into the coolant and activation of corrosion products in the reactor coolant. These radioactive materials in the coolant can plate out in the RCS, and, at times, an accumulation will break away to spike the normal level of radioactivity. The release of coolant during a Design Basis Accident (DBA) could send radioactive materials into the environment.

Limits on the maximum allowable level of radioactivity in the reactor coolant are established to ensure, in the event of a release of any radioactive material to the environment during a DBA, radiation doses are maintained within the limits of 10 CFR 100 (Ref. 1).

This LCO contains iodine specific activity limits. The iodine isotopic activities per gram of reactor coolant are expressed in terms of a DOSE EQUIVALENT I-131. The allowable levels are intended to limit the 2 hour radiation dose to an individual at the site boundary to a small fraction of the 10 CFR 100 limit.

APPLICABLE SAFETY ANALYSES

Analytical methods and assumptions involving radioactive material in the primary coolant are presented in the FSAR (Ref. 2). The specific activity in the reactor coolant (the source term) is an initial condition for evaluation of the consequences of an accident due to a main steam line break (MSLB) outside containment. No fuel damage is postulated in the MSLB accident, and the release of radioactive material to the environment is assumed to end when the main steam isolation valves (MSIVs) close completely.

This MSLB release forms the basis for determining offsite doses (Ref. 2). The limits on the specific activity of the primary coolant ensure that the 2 hour thyroid and whole body doses at the site boundary, resulting from an MSLB outside containment during steady state operation, will not exceed 10% of the dose guidelines of 10 CFR 100.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limit on specific activity is a value from a parametric evaluation of typical site locations. This limit is conservative because the evaluation considered more restrictive parameters than for a specific site, such as the location of the site boundary and the meteorological conditions of the site.

RCS specific activity satisfies Criterion 2 of the NRC Policy Statement (Ref. 3).

LCO

The specific iodine activity is limited to ≤ 0.2 μCi/gm DOSE EQUIVALENT I-131. This limit ensures the source term assumed in the safety analysis for the MSLB is not exceeded, so any release of radioactivity to the environment during an MSLB is less than a small fraction of the 10 CFR 100 limits.

APPLICABILITY

In MODE 1, and MODES 2 and 3 with any main steam line not isolated, limits on the primary coolant radioactivity are applicable since there is an escape path for release of radioactive material from the primary coolant to the environment in the event of an MSLB outside of primary containment.

In MODES 2 and 3 with the main steam lines isolated, such limits do not apply since an escape path does not exist. In MODES 4 and 5, no limits are required since the reactor is not pressurized and the potential for leakage is reduced.

ACTIONS

A.1 and A.2

When the reactor coolant specific activity exceeds the LCO DOSE EQUIVALENT I-131 limit, but is ≤ 4.0 μCi/gm, samples must be analyzed for DOSE EQUIVALENT I-131 at least once every 4 hours. In addition, the specific activity must be restored to the LCO limit within 48 hours. The Completion Time of once every 4 hours is based on the time needed to take and analyze a sample. The 48 hour Completion Time to restore the activity level provides a reasonable time for temporary coolant activity increases (iodine spikes or crud bursts) to be cleaned up with the normal processing systems.

A Note to the Required Actions of Condition A excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE(S) while relying on the

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

ACTIONS even though the ACTIONS may eventually require plant shutdown. This exception is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

B.1, B.2.1, B.2.2.1, and B.2.2.2

If the DOSE EQUIVALENT I-131 cannot be restored to ≤ 0.2 μCi/gm within 48 hours, or if at any time it is > 4.0 μCi/gm, it must be determined at least every 4 hours and all the main steam lines must be isolated within 12 hours. Isolating the main steam lines precludes the possibility of releasing radioactive material to the environment in an amount that is more than a small fraction of the requirements of 10 CFR 100 during a postulated MSLB accident.

Alternately, the plant can be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. This option is provided for those instances when isolation of main steam lines is not desired (e.g., due to the decay heat loads). In MODE 4, the requirements of the LCO are no longer applicable.

The Completion Time of once every 4 hours is the time needed to take and analyze a sample. The 12 hour Completion Time is reasonable, based on operating experience, to isolate the main steam lines in an orderly manner and without challenging plant systems. Also, the allowed Completion Times for Required Actions B.2.2.1 and B.2.2.2 for bringing the plant to MODES 3 and 4 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 3.4.8.1 1C

This Surveillance is performed to ensure iodine remains within limit during normal operation. The 7 day Frequency is adequate to trend changes in the iodine activity level.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1 (continued) |C

This SR is modified by a Note that requires this Surveillance to be performed only in MODE 1 because the level of fission products generated in other MODES is much less.

REFERENCES

1. 10 CFR 100.11.

2. FSAR, Section 15.6.4.

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

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown 1C

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 reduce the temperature of the reactor coolant to ≤ 200°F in preparation for performing Refueling or Cold Shutdown maintenance operations, or the decay heat must be removed for maintaining the reactor in the Hot 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, 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 System (LCO 3.7.1, "Standby Service Water (SW) System and Ultimate Heat Sink (UHS)").

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 shutdown cooling subsystem must be in operation. An OPERABLE RHR shutdown cooling subsystem consists of one OPERABLE RHR pump, one 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 3, one RHR shutdown cooling subsystem can provide the required cooling, but two subsystems are required to be OPERABLE to provide redundancy. Operation of

(continued)

BASES

LCO (continued)

one subsystem can maintain or reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required.

Note 1 permits both RHR shutdown cooling subsystems and recirculation pumps to be shut down for a period of 2 hours in an 8 hour period. Note 2 allows one RHR shutdown cooling subsystem to be inoperable for up to 2 hours for performance of surveillance tests. These tests may be on the affected RHR System or on some other plant system or component that necessitates placing the RHR System in an inoperable status during the performance. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR subsystems or other operations requiring RHR flow interruption and loss of redundancy.

APPLICABILITY

In MODE 3 with reactor steam dome pressure below the RHR cut-in permissive pressure (i.e., the actual pressure at which the interlock resets) the RHR Shutdown Cooling System must be OPERABLE and shall be operated in the shutdown cooling mode to remove decay heat to reduce or maintain coolant temperature. Otherwise, a recirculation pump is required to be in operation.

In MODES 1 and 2, and in MODE 3 with reactor steam dome pressure greater than or equal to the RHR cut-in permissive pressure, this LCO is not applicable. Operation of the RHR System in the shutdown cooling mode is not allowed above this pressure because the RCS pressure may exceed the design pressure of the shutdown cooling piping. Decay heat removal at reactor pressures greater than or equal to the RHR cut-in permissive pressure is typically accomplished by condensing the steam in the main condenser. Additionally, in MODE 2 below this pressure, the OPERABILITY requirements for the Emergency Core Cooling Systems (ECCS) (LCO 3.5.1, "ECCS—Operating") do not allow placing the RHR shutdown cooling subsystem into operation.

The requirements for decay heat removal in MODES 4 and 5 are discussed in LCO 3.4.10, "Residual Heat Removal (RHR) Shutdown Cooling System—Cold Shutdown"; LCO 3.9.8, "Residual Heat Removal (RHR)—High Water Level"; and LCO 3.9.9, "Residual Heat Removal (RHR)—Low Water Level."

(continued)

BASES (continued)

ACTIONS

A Note to the ACTIONS excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE(S) while relying on the ACTIONS even though the ACTIONS may eventually require plant shutdown. This exception is acceptable due to the redundancy of the OPERABLE subsystems, the low pressure at which the plant is operating, the low probability of an event occurring during operation in this condition, and the availability of alternate methods of decay heat removal capability.

A second 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, A.2, and A.3

With one RHR shutdown cooling subsystem inoperable for decay heat removal, except as permitted by LCO Note 2, the inoperable subsystem must be restored to OPERABLE status without delay. In this condition, the remaining OPERABLE subsystem can provide the necessary decay heat removal. The overall reliability is reduced, however, because a single 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.

(continued)

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. | 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)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1 | C

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.

This Surveillance is modified by a Note allowing sufficient time to align the RHR System for shutdown cooling operation after clearing the pressure interlock that isolates the system, or for placing a recirculation pump in operation. The Note takes exception to the requirements of the Surveillance being met (i.e., forced coolant circulation is not required for this initial 2 hour period), which also allows entry into the Applicability of this Specification in accordance with SR 3.0.4 since the Surveillance will not be "not met" at the time of entry into the Applicability.

REFERENCES

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

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 in preparation for performing Refueling maintenance operations, or the decay heat must be removed 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, 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

LCO (continued)

can maintain and reduce the reactor coolant temperature as required. To ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required.

Note 1 permits both RHR shutdown cooling subsystems and recirculation pumps to be shut down for a period of 2 hours in an 8 hour period. Note 2 allows one RHR shutdown cooling subsystem to be inoperable for up to 2 hours for performance of Surveillance tests. These tests may be on the affected RHR System or on some other plant system or component that necessitates placing the RHR System in an inoperable status during the performance. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR subsystems or other operations requiring RHR flow interruption and loss of redundancy.

APPLICABILITY

In MODE 4, the RHR Shutdown Cooling System must be OPERABLE and shall be operated in the shutdown cooling mode to remove decay heat to maintain coolant temperature below 200°F. Otherwise, a recirculation pump is required to be in operation.

In MODES 1 and 2, and in MODE 3 with reactor steam dome pressure greater than or equal to the RHR cut-in permissive pressure, this LCO is not applicable. Operation of the RHR System in the shutdown cooling mode is not allowed above this pressure because the RCS pressure may exceed the design pressure of the shutdown cooling piping. Decay heat removal at reactor pressures greater than or equal to the RHR cut-in permissive pressure is typically accomplished by condensing the steam in the main condenser. Additionally, in MODE 2 below this pressure, the OPERABILITY requirements for the Emergency Core Cooling Systems (ECCS) (LCO 3.5.1, "ECCS—Operating") do not allow placing the RHR shutdown cooling subsystem into operation.

The requirements for decay heat removal in MODE 3 below the cut in permissive pressure and in MODE 5 are discussed in LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown"; LCO 3.9.8, "Residual Heat Removal (RHR)—High Water Level"; and LCO 3.9.9, "Residual Heat Removal (RHR)—Low Water Level." 1C

(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 3.4.10.1

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 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).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system pressure and temperature changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

The Specification contains P/T limit curves for heatup, cooldown, inservice leak and hydrostatic testing, and criticality, and also limits the maximum rate of change of reactor coolant temperature.

Each P/T limit curve defines an acceptable region for normal operation. The usual use of the curves is operational guidance during heatup or cooldown maneuvering, when pressure and temperature indications are monitored and compared to the applicable curve to determine that operation is within the allowable region.

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the reactor coolant pressure boundary (RCPB). The vessel is the component most subject to brittle failure. Therefore, the LCO limits apply mainly to the vessel.

10 CFR 50, Appendix G (Ref. 1), requires the establishment of P/T limits for material fracture toughness requirements of the RCPB materials. Reference 1 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the American Society of Mechanical Engineers (ASME) Code, Section III, Appendix G (Ref. 2).

The actual shift in the RT_{NDT} of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance

(continued)

BASES

BACKGROUND (continued)

with ASTM E 185 (Ref. 3) and 10 CFR 50, Appendix H (Ref. 4). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of Reference 5.

The P/T limit curves are composite curves established by superimposing limits derived from linear elastic fracture mechanics (LEFM) analyses of those portions of the reactor vessel and head that are the most restrictive. At any specific pressure, temperature, and temperature rate of change, one location within the reactor vessel will dictate the most restrictive limit. Across the span of the P/T limit curves, different locations are more restrictive, and, thus, the curves are composites of the most restrictive regions.

The heatup curve represents a different set of restrictions than the cooldown curve because the directions of the thermal gradients through the vessel wall are reversed. The thermal gradient reversal alters the location of the tensile stress between the outer and inner walls. However, only the more restrictive of the two curves is used.

The P/T criticality limits include the Reference 1 requirement that they be at least 40°F above the heatup curve or the cooldown curve and not lower than the minimum permissible temperature for the inservice leak and hydrostatic testing. 1C

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the RCPB, possibly leading to a nonisolable leak or loss of coolant accident. In the event these limits are exceeded, an evaluation must be performed to determine the effect on the structural integrity of the RCPB components. The ASME Code, Section XI, Appendix E (Ref. 6), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, a condition that is unanalyzed. References 7 and 8 approved 1C

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

the curves and limits required by this Specification. Since the P/T limits are not derived from any DBA, there are no acceptance limits related to the P/T limits. Rather, the P/T limits are acceptance limits themselves since they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of the NRC Policy Statement (Ref. 9).

LCO

The elements of this LCO are:

a. RCS pressure and temperature are within the limits specified in Figures 3.4.11-1, 3.4.11-2, and 3.4.11-3 and heatup and cooldown rates are ≤ 100°F in any 1 hour period during RCS heatup, cooldown, and inservice leak and hydrostatic testing, and the RCS temperature change during inservice leak and hydrostatic testing is ≤ 20°F in any 1 hour period when the RCS pressure and RCS temperature are not within the limits of Figure 3.4.11-2;

b. The temperature difference between the reactor vessel bottom head coolant and the reactor pressure vessel (RPV) coolant is ≤ 145°F during recirculation pump startup, and during increases in THERMAL POWER or loop flow while operating at low THERMAL POWER or loop flow;

c. The temperature difference between the reactor coolant in the respective recirculation loop and in the reactor vessel is ≤ 50°F during recirculation pump startup, and during increases in THERMAL POWER or loop flow while operating at low THERMAL POWER or loop flow;

d. RCS pressure and temperature are within the limits specified in Figure 3.4.11-3, prior to achieving criticality; and

e. The reactor vessel flange and the head flange temperatures are ≥ 80°F when tensioning the reactor vessel head bolting studs.

These limits define allowable operating regions and permit a large number of operating cycles while also providing a wide margin to nonductile failure.

(continued)

BASES

LCO (continued)

The rate of change of temperature limits controls the thermal gradient through the vessel wall and is used as input for calculating the heatup, cooldown, and inservice leak and hydrostatic testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves.

Violation of the limits places the reactor vessel outside of the bounds of the LEFM analyses and can increase stresses in other RCS components. The consequences depend on several factors, as follows:

a. The severity of the departure from the allowable operating pressure temperature regime or the severity of the rate of change of temperature;

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

c. The existence, size, and orientation of flaws in the vessel material.

APPLICABILITY

The potential for violating a P/T limit exists at all times. For example, P/T limit violations could result from ambient temperature conditions that result in the reactor vessel metal temperature being less than the minimum allowed temperature for boltup. Therefore, this LCO is applicable even when fuel is not loaded in the core.

ACTIONS

A.1 and A.2

Operation outside the P/T limits while in MODE 1, 2, or 3 must be corrected so that the RCPB is returned to a condition that has been verified by LEFM analyses.

The 30 minute Completion Time reflects the urgency of restoring the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

and must be completed if continued operation is desired. Several methods may be used, including comparison with pre-analyzed transients, new analyses, or inspection of the components. ASME Code, Section XI, Appendix E (Ref. 6), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

The 72 hour Completion Time is reasonable to accomplish the evaluation of a mild violation. More severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed if continued operation is desired.

Condition A is modified by a Note requiring Required Action A.2 be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action A.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be brought to a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress, or a sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. With the reduced pressure and temperature conditions, the possibility of propagation of undetected flaws is decreased.

Pressure and temperature are reduced by bringing the plant 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.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

Operation outside the P/T limits in other than MODES 1, 2, and 3 (including defueled conditions) must be corrected so that the RCPB is returned to a condition that has been verified by LEFM analyses. The Required Action must be initiated without delay and continued until the limits are restored.

Besides restoring the P/T limit parameters to within limits, an evaluation is required to determine if RCS operation is allowed. This evaluation must verify that the RCPB integrity is acceptable and must be completed before approaching criticality or heating up to > 200°F. Several methods may be used, including comparison with pre-analyzed transients, new analyses, or inspection of the components. ASME Section XI, Appendix E (Ref. 6), may be used to support the evaluation; however, its use is restricted to evaluation of the beltline.

Condition C is modified by a Note requiring Required Action C.2 be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action C.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Verification that operation is within limits is required every 30 minutes when RCS pressure and temperature conditions are undergoing planned changes. This Frequency is considered reasonable in view of the control room indication available to monitor RCS status. Also, since temperature rate of change limits are specified in hourly increments, 30 minutes permits assessment and correction of minor deviations. The limits of Figures 3.4.11-1, 3.4.11-2, and 3.4.11-3 are met when operation is to the right of the applicable limit curves.

Surveillance for heatup, cooldown, or inservice leakage and hydrostatic testing may be discontinued when the criteria given in the relevant plant procedure for ending the activity are satisfied.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1 (continued)

This SR has been modified by a Note that requires this Surveillance to be performed only during system heatup and cooldown operations and inservice leakage and hydrostatic testing.

SR 3.4.11.2

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. The limits of Figure 3.4.11-3 are met when operation is to the right of the limit curve.

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 3.4.11.3 and SR 3.4.11.4

Differential temperatures within the applicable 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. 10) 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 3.4.11.4 is to compare the temperatures of the operating recirculation loop and the idle loop.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.3 and SR 3.4.11.4 (continued)

SR 3.4.11.3 and SR 3.4.11.4 have been modified by a Note that requires the Surveillance to be met only in MODES 1, 2, 3, and 4 during a recirculation pump startup, since this is when the stresses occur. In MODE 5, the overall stress on limiting components is lower; therefore, ΔT limits are not required.

SR 3.4.11.5 and SR 3.4.11.6

Differential temperatures within the applicable limits ensure that thermal stresses resulting from increases in THERMAL POWER or recirculation loop flow during single recirculation loop operation will not exceed design allowances. Performing the Surveillance within 15 minutes before beginning such an increase in power or flow rate provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the change in operation.

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.11.6 is to compare the temperatures of the operating recirculation loop and the idle loop.

Plant specific startup test data has determined that the bottom head is not subject to temperature stratification at power levels > 25% of RTP and with single loop flow rate > 10% of rated loop flow. Therefore, SR 3.4.11.5 and SR 3.4.11.6 have been modified by a Note that requires the Surveillance to be met only under these conditions. The Note for SR 3.4.11.6 further limits the requirement for this Surveillance to exclude comparison of the idle loop temperature if the idle loop is isolated from the RPV since the water in the loop can not be introduced into the remainder of the Reactor Coolant System.

SR 3.4.11.7, SR 3.4.11.8, and SR 3.4.11.9

Limits on the reactor vessel flange and head flange temperatures are generally bounded by the other P/T limits during system heatup and cooldown. However, operations

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.7, SR 3.4.11.8, and SR 3.4.11.9 (continued)

approaching MODE 4 from MODE 5 and in MODE 4 with RCS temperature less than or equal to certain specified values require assurance that these temperatures meet the LCO Limits.

The flange temperatures must be verified to be above the limits 30 minutes before and while tensioning the vessel head bolting studs to ensure that once the head is tensioned the limits are satisfied. When in MODE 4 with RCS temperature ≤ 90°F, 30 minute checks of the flange temperatures are required because of the reduced margin to the limits. When in MODE 4 with RCS temperature ≤ 100°F, monitoring of the flange temperature is required every 12 hours to ensure the temperatures are within the specified limits.

The 30 minute Frequency reflects the urgency of maintaining the temperatures within limits, and also limits the time that the temperature limits could be exceeded. The 12 hour Frequency is reasonable based on the rate of temperature change possible at these temperatures.

SR 3.4.11.7 is modified by a Note that requires the Surveillance to be performed only when tensioning the reactor vessel head bolting studs. SR 3.4.11.8 is modified by a Note that requires the Surveillance to be initiated 30 minutes after RCS temperature ≤ 90°F in MODE 4. SR 3.4.11.9 is modified by a Note that requires the Surveillance to be initiated 12 hours after RCS temperature ≤ 100°F in MODE 4. The Notes contained in these SRs are necessary to specify when the reactor vessel flange and head flange temperatures are required to be verified to be within the specified limits.

REFERENCES

1. 10 CFR 50, Appendix G.
2. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.
3. ASTM E 185-82, July 1982.
4. 10 CFR 50, Appendix H.

(continued)

BASES

REFERENCES (continued)

5. Regulatory Guide 1.99, Revision 2, May 1988.

6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

7. Letter from D.G. Eisenhut (NRC) to D.W. Mazur (WPPSS), "Issuance of Facility Operating License NPF-21 - WPPSS Nuclear Project No. 2," dated December 20, 1983.

8. Letter from J.W. Clifford (NRC) to J.V. Parrish (WPPSS), "Issuance of Amendment 137 for the WPPSS Nuclear Project No. 2," dated May 2, 1995. C

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

10. FSAR, Section 15.4.4. C

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Reactor Steam Dome Pressure

BASES

BACKGROUND	The reactor steam dome pressure is an assumed value in the determination of compliance with reactor pressure vessel overpressure protection criteria and is also an assumed initial condition of Design Basis Accidents (DBAs) and transients.
APPLICABLE SAFETY ANALYSES	The reactor steam dome pressure of ≤ 1035 psig is an initial condition of the vessel overpressure protection analysis of Reference 1. This analysis assumes an initial maximum reactor steam dome pressure and evaluates the response of the pressure relief system, primarily the safety/relief valves, during the limiting pressurization transient. The determination of compliance with the overpressure criteria is dependent on the initial reactor steam dome pressure; therefore, the limit on this pressure ensures that the assumptions of the overpressure protection analysis are conserved. Reference 2 also assumes an initial reactor steam dome pressure for the analyses of DBAs and transients used to determine the limits for fuel cladding integrity (see Bases for LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and 1% fuel cladding plastic strain (see Bases for LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)"). While the transient analyses assume an initial reactor steam dome pressure of 1020 psig, this value is more conservative than a higher reactor pressure, e.g., 1035 psig, with respect to the thermal limits attained during the transients. Therefore, the reactor steam dome pressure assumed in these analyses is bounded by the vessel overpressure protection analysis. Reactor steam dome pressure satisfies the requirements of Criterion 2 of the NRC Policy Statement (Ref. 3).
LCO	The specified reactor steam dome pressure limit of ≤ 1035 psig ensures the plant is operated within the assumptions of the reactor overpressure analyses. Operation above the limit may result in a response more severe than analyzed.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1 and 2, the reactor steam dome pressure is required to be less than or equal to the limit. In these MODES, the reactor may be generating significant steam, and events that may challenge the overpressure limits are possible.

In MODES 3, 4, and 5, the limit is not applicable because the reactor is shut down. In these MODES, the reactor pressure is well below the required limit, and no anticipated events will challenge the overpressure limits.

ACTIONS

A.1

With the reactor steam dome pressure greater than the limit, prompt action should be taken to reduce pressure to below the limit and return the reactor to operation within the bounds of the analyses. The 15 minute Completion Time is reasonable considering the importance of maintaining the pressure within limits. This Completion Time also ensures that the probability of an accident while pressure is greater than the limit is minimal.

B.1

If the reactor steam dome pressure cannot be restored to within the limit 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. 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 3.4.12.1

Verification that reactor steam dome pressure is ≤ 1035 psig ensures that the initial conditions of the vessel overpressure protection analysis is met. Operating experience has shown the 12 hour Frequency to be sufficient for identifying trends and verifying operation within safety analyses assumptions.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Section 5.2.2.
2. FSAR, Chapters 15 and 15.F.
3. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

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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. 1B

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 ≤ 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 7 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 1C

(continued)

BASES

ACTIONS

A.1 (continued)

being able to perform its intended safety function. The 7 day Completion Time is based on a reliability study (Ref. 13) that evaluated the impact on ECCS availability by assuming that various components and subsystems were taken 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 immediately 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. Immediate verification of RCIC OPERABILITY 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 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 immediately 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. 13) 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

(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 72 hours 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 14 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. 13) and has been found to be acceptable through operating experience.

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

BASES

ACTIONS

F.1 and F.2 (continued)

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 basis LOCA could result in the minimum required ECCS equipment not being available. Since both a high pressure (ADS) and low pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the low pressure ECCS injection/spray subsystem or the ADS valve to OPERABLE status. This Completion Time is based on a reliability study (Ref. 13) and has been found to be acceptable through operating experience. 1C

G.1 and G.2

If any Required Action and associated Completion Time of Condition E or F are not met or if two or more required ADS valves are inoperable, the plant must be brought to a condition 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 reactor steam dome pressure reduced to ≤ 150 psig 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.

H.1

When multiple ECCS subsystems are inoperable, as stated in Condition H, the plant is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge lines of the HPCS System, LPCS System, and LPCI subsystems full of water ensures that the systems will perform properly, injecting their full capacity into the RCS upon demand. This will also prevent a water hammer following an ECCS initiation signal. One acceptable method of ensuring

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.7 (continued)

900 psig (consistent with the recommendations of the vendor). Adequate steam flow is represented by THERMAL POWER ≥ 10% RTP. Reactor startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements, prior to reactor startup. Therefore, this SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for manual actuation after the required pressure and flow are reached is sufficient to achieve stable conditions and provides adequate time to complete the SR. SR 3.5.1.6 and the LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlap this Surveillance to provide complete testing of the assumed safety function.

The Frequency of 24 months on a STAGGERED TEST BASIS ensures that both ADS trip system solenoids for each required ADS valve are alternately tested. The Frequency is based on the need to perform this Surveillance under the conditions that apply just prior to or during a startup from a plant outage. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. 1C

REFERENCES

1. FSAR, Section 6.3.2.2.3.
2. FSAR, Section 6.3.2.2.4.
3. FSAR, Section 6.3.2.2.1.
4. FSAR, Section 6.3.2.2.2.
5. FSAR, Section 15.6.6.
6. FSAR, Section 15.6.4.
7. FSAR, Section 15.6.5.
8. 10 CFR 50, Appendix K.
9. FSAR, Section 6.3.3.

(continued)

BASES

REFERENCES (continued)

10. 10 CFR 50.46.

11. FSAR, Section 6.3.3.3.

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

13. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.

14. NEDC-32115P, Washington Public Power Supply System Nuclear Project 2, "SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," Revision 2, July 1993. C

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.

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)

BASES

LCO (continued)

LPCI mode and not otherwise inoperable. Alignment and operation for decay heat removal includes when the RHR pump is not operating or when the system is being realigned from or to the RHR shutdown cooling mode. Because of low pressure and low temperature conditions in MODES 4 and 5, sufficient time will be available to manually align and initiate LPCI subsystem operation to provide core cooling prior to postulated fuel uncovery.

APPLICABILITY

OPERABILITY of the ECCS injection/spray subsystems is required in MODES 4 and 5 to ensure adequate coolant inventory and sufficient heat removal capability for the irradiated fuel in the core in case of an inadvertent draindown of the vessel. Requirements for ECCS OPERABILITY during MODES 1, 2, and 3 are discussed in the Applicability section of the Bases for LCO 3.5.1. ECCS subsystems are not required to be OPERABLE during MODE 5 with the spent fuel storage pool gates removed and the water level maintained at ≥ 22 ft above the RPV flange. This provides sufficient coolant inventory to allow operator action to terminate the inventory loss prior to fuel uncovery in case of an inadvertent draindown.

The Automatic Depressurization System is not required to be OPERABLE during MODES 4 and 5 because the RPV pressure is < 150 psig, and the LPCS, HPCS, and LPCI subsystems can provide core cooling without any depressurization of the primary system.

ACTIONS

A.1 and B.1

If any one required ECCS injection/spray subsystem is inoperable, the required inoperable ECCS injection/spray subsystem must be restored to OPERABLE status within 4 hours. In this condition, the remaining OPERABLE subsystem can provide sufficient RPV flooding capability to recover from an inadvertent vessel draindown. However, overall system reliability is reduced because a single failure in the remaining OPERABLE subsystem concurrent with a vessel draindown could result in the ECCS not being able to perform its intended function. The 4 hour Completion Time for restoring the required ECCS injection/spray subsystem to OPERABLE status is based on engineering judgment that considered the availability of one subsystem and the low probability of a vessel draindown event.

(continued)

BASES

ACTIONS

A.1 and B.1 (continued)

With the inoperable subsystem not restored to OPERABLE status within the required Completion Time, action must be initiated immediately to suspend operations with a potential for draining the reactor vessel (OPDRVs) to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

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

If both of the required ECCS injection/spray subsystems are inoperable, all coolant inventory makeup capability may be unavailable. Therefore, actions must be initiated immediately to suspend OPDRVs in order to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended. One ECCS injection/spray subsystem must also be restored to OPERABLE status within 4 hours. The 4 hour Completion Time to restore at least one ECCS injection/spray subsystem to OPERABLE status ensures that prompt action will be taken to provide the required cooling capacity or to initiate actions to place the plant in a condition that minimizes any potential fission product release to the environment.

If at least one ECCS injection/spray subsystem is not restored to OPERABLE status within the 4 hour Completion Time, additional actions are required to minimize any potential fission product release to the environment. This includes ensuring secondary containment is OPERABLE; one standby gas treatment subsystem is OPERABLE; and secondary containment isolation capability is available in each secondary containment penetration flow path not isolated that is assumed to be isolated to mitigate radioactivity releases (i.e., one secondary containment isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability. These administrative controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated). This may be performed by an administrative check, by examining logs or other

(continued)

BASES

ACTIONS

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

information, to determine if the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the Surveillances may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1 and SR 3.5.2.2

The minimum water level of 18 ft 6 inches required for the suppression pool is periodically verified to ensure that the suppression pool will provide adequate net positive suction head (NPSH) for the ECCS pumps, recirculation volume (135,000 gallons consistent with the CST volume requirements described below), and vortex prevention. With the suppression pool water level less than the required limit, all ECCS injection/spray subsystems are inoperable unless they are aligned to an OPERABLE CST.

When the suppression pool level is < 18 ft 6 inches, the HPCS System is considered OPERABLE only if it can take suction from the CST and the CST water level is sufficient to provide the required NPSH for the HPCS pump. Therefore, a verification that either the suppression pool water level is ≥ 18 ft 6 inches or the HPCS System is aligned to take suction from the CST and the CST contains ≥ 135,000 gallons of water, equivalent to a level of 13.25 ft in a single CST or 7.6 ft in each CST, ensures that the HPCS System can supply makeup water to the RPV.

The 12 hour Frequency of these SRs was developed considering operating experience related to suppression pool and CST water level variations and instrument drift during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications in the control room, including alarms, to alert the operator to an abnormal suppression pool or CST water level condition.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.3, SR 3.5.2.5, and SR 3.5.2.6

The Bases provided for SR 3.5.1.1, SR 3.5.1.4, and SR 3.5.1.5 are applicable to SR 3.5.2.3, SR 3.5.2.5, and SR 3.5.2.6, respectively.

SR 3.5.2.4

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. The 31 day Frequency is appropriate because the valves are operated under procedural control and the probability of their being mispositioned during this time period is low.

In MODES 4 and 5, the RHR System may be required to operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. Therefore, this SR is modified by a Note that allows one LPCI subsystem to be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. Alignment and operation for decay heat removal includes when the required RHR pump is not operating or when the system is being realigned from or to the RHR shutdown cooling mode. Because of the low pressure and low temperature conditions in MODES 4 and 5, sufficient time will be available to manually align and initiate LPCI subsystem operation to provide core cooling prior to postulated fuel uncovery. This will ensure adequate core cooling if an inadvertent vessel draindown should occur.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Section 6.3.3.4.
2. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

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

B 3.5.3 RCIC System

BASES

BACKGROUND

The RCIC System is not part of the ECCS; however, the RCIC System is included with the ECCS section because of their similar functions.

The RCIC System is designed to operate either automatically or manually following reactor pressure vessel (RPV) isolation accompanied by a loss of coolant flow from the feedwater system to provide adequate core cooling and control of RPV water level. Under these conditions, the High Pressure Core Spray (HPCS) and RCIC systems perform similar functions. The RCIC System design requirements ensure that the criteria of Reference 1 are satisfied.

The RCIC System (Ref. 2) consists of a steam driven turbine pump unit, piping and valves to provide steam to the turbine, as well as piping and valves to transfer water from the suction source to the core via the head spray nozzle. Suction piping is provided from the condensate storage tank (CST) and the suppression pool. Pump suction is normally aligned to the CST to minimize injection of suppression pool water into the RPV. However, if the CST water supply is low an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the RCIC System. The steam supply to the turbine is piped from main steam line B, upstream of the inboard main steam line isolation valve.

The RCIC System is designed to provide core cooling for a wide range of reactor pressures, 165 psia to 1225 psia. Upon receipt of an initiation signal, the RCIC turbine accelerates to a specified speed. As the RCIC flow increases, the turbine control valve is automatically adjusted to maintain design flow. Exhaust steam from the RCIC turbine is discharged to the suppression pool. A full flow test line is provided to route water to the CST to allow testing of the RCIC System during normal operation without injecting water into the RPV.

The RCIC pump is provided with a minimum flow bypass line, which discharges to the suppression pool. The valve in this line automatically opens to prevent pump damage due to

(continued)

BASES

BACKGROUND (continued)

overheating when other discharge line valves are closed. To ensure rapid delivery of water to the RPV and to minimize water hammer effects, the RCIC System discharge line "keep fill" system is designed to maintain the pump discharge line filled with water.

APPLICABLE SAFETY ANALYSES

The function of the RCIC System is to respond to transient events by providing makeup coolant to the reactor. The RCIC System is not an Engineered Safety Feature System and no credit is taken in the safety analyses for RCIC System operation. Based on its contribution to the reduction of overall plant risk, however, the system satisfies Criterion 4 of the NRC Policy Statement (Ref.3).

LCO

The OPERABILITY of the RCIC System provides adequate core cooling such that actuation of any of the ECCS subsystems is not required in the event of RPV isolation accompanied by a loss of feedwater flow. The RCIC System has sufficient capacity to maintain RPV inventory during an isolation event.

APPLICABILITY

The RCIC System is required to be OPERABLE in MODE 1, and MODES 2 and 3 with reactor steam dome pressure > 150 psig since RCIC is the primary non-ECCS water source for core cooling when the reactor is isolated and pressurized. In MODES 2 and 3 with reactor steam dome pressure ≤ 150 psig, and in MODES 4 and 5, RCIC is not required to be OPERABLE since the ECCS injection/spray subsystems can provide sufficient flow to the vessel.

ACTIONS

A.1 and A.2

If the RCIC System is inoperable during MODE 1, or MODES 2 or 3 with reactor steam dome pressure > 150 psig, and the HPCS System is immediately verified to be OPERABLE, the RCIC System must be restored to OPERABLE status within 14 days. In this Condition, loss of the RCIC System will not affect the overall plant capability to provide makeup inventory at high RPV pressure since the HPCS System is the only high pressure system assumed to function during a loss of coolant accident (LOCA). OPERABILITY of the HPCS is therefore immediately verified when the RCIC System is inoperable. This may be performed as an administrative check, by

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

examining logs or other information, to determine if the HPCS is out of service for maintenance or other reasons. Verification does not require performing the Surveillances needed to demonstrate the OPERABILITY of the HPCS System. If the OPERABILITY of the HPCS System cannot be immediately verified, however, Condition B must be immediately entered. For transients and certain abnormal events with no LOCA, RCIC (as opposed to HPCS) is the preferred source of makeup coolant because of its relatively small capacity, which allows easier control of RPV water level. Therefore, a limited time is allowed to restore the inoperable RCIC to OPERABLE status.

The 14 day Completion Time is based on a reliability study (Ref. 4) that evaluated the impact on ECCS availability, assuming that various components and subsystems were taken 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 (AOTs). Because of the similar functions of the HPCS and RCIC, the AOTs (i.e., Completion Times) determined for the HPCS are also applied to RCIC.

B.1 and B.2

If the RCIC System cannot be restored to OPERABLE status within the associated Completion Time, or if the HPCS System is simultaneously inoperable, the plant must be brought to a condition 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 reactor steam dome pressure reduced to ≤ 150 psig 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 3.5.3.1

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge line of the RCIC System full of water ensures that the system will perform properly, injecting its full capacity into the Reactor Coolant System upon demand. This will also

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1 (continued)

prevent a water hammer following an initiation signal. One acceptable method of ensuring the line is full is to vent at the high points. The 31 day Frequency is based on the gradual nature of void buildup in the RCIC piping, the procedural controls governing system operation, and operating experience.

SR 3.5.3.2

Verifying the correct alignment for manual, power operated, and automatic valves in the RCIC flow path provides assurance that the proper flow path will exist for RCIC operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. For the RCIC System, this SR also includes the steam flow path for the turbine and the flow controller position.

The 31 day Frequency of this SR was derived from the Inservice Testing Program requirements for performing valve testing at least every 92 days. The Frequency of 31 days is further justified because the valves are operated under procedural control and because improper valve position would affect only the RCIC System. This Frequency has been shown to be acceptable through operating experience.

SR 3.5.3.3 and SR 3.5.3.4

The RCIC pump flow rates ensure that the system can maintain reactor coolant inventory during pressurized conditions with the RPV isolated. The flow tests for the RCIC System are performed at two different pressure ranges such that system capability to provide rated flow against a system head corresponding to reactor pressure is tested both at the

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.3.3 and SR 3.5.3.4 (continued)

higher and lower operating ranges of the system. The required system head should overcome the RPV pressure and associated discharge line losses. Adequate reactor steam pressure must be available to perform these tests. Additionally, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the RCIC System diverts steam flow. Therefore, sufficient time is allowed after adequate pressure and flow are achieved to perform these SRs. Adequate reactor steam pressure to perform SR 3.5.3.3 is 935 psig and to perform SR 3.5.3.4 is 150 psig. Adequate steam flow to perform SR 3.5.3.3 is represented by THERMAL POWER ≥ 10% RTP and to perform SR 3.5.3.4 is represented by turbine bypass valves ≥ 10% open. Reactor startup is allowed prior to performing the low pressure Surveillance because the reactor pressure is low and the time to satisfactorily perform the Surveillance is short. The reactor pressure is allowed to be increased to normal operating pressure since it is assumed that the low pressure test has been satisfactorily completed and there is no indication or reason to believe that RCIC is inoperable. Therefore, these SRs are modified by Notes that state the Surveillances are not required to be performed until 12 hours after the reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for the flow tests after the required pressure and flow are reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SRs.

A 92 day Frequency for SR 3.5.3.3 is consistent with the Inservice Testing Program requirements. The 24 month Frequency for SR 3.5.3.4 is based on the need to perform this Surveillance under the conditions that apply just prior to or during startup from a plant outage. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.5.3.5

The RCIC System is required to actuate automatically to perform its design function. This Surveillance verifies that with a required system initiation signal (actual or

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.3.5 (continued)

simulated) the automatic initiation logic of RCIC will cause the system to operate as designed, including actuation of the system throughout its emergency operating sequence, automatic pump startup and actuation of all automatic valves to their required positions. This Surveillance test also ensures that the RCIC System will automatically restart on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) trip and that the suction is automatically transferred from the CST to the suppression pool. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.2 overlaps this Surveillance to provide complete testing of the assumed design function.

While this Surveillance can be performed with the reactor at power, operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes vessel injection during the Surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the test line, coolant injection into the RPV is not required during the Surveillance.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 33.

2. FSAR, Section 5.4.6.2.

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

4. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.

BASES

ACTIONS (continued)

A.1 and A.2

With one or more penetration flow paths with one PCIV inoperable except for secondary containment bypass leakage rate, MSIV leakage rate, or hydrostatically tested lines leakage rate not within limits, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available one to the primary containment. The Required Action must be completed within the 4 hour Completion Time (8 hours for main steam lines). The specified time period of 4 hours is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. For main steam lines, an 8 hour Completion Time is allowed. The Completion Time of 8 hours for the main steam lines allows a period of time to restore the MSIVs to OPERABLE status given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident, and no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that those devices outside primary containment and capable of being mispositioned are in the correct position. The Completion Time for this verification of "once per 31 days for isolation devices outside primary containment, drywell, and steam tunnel," is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low. For devices inside primary containment, the specified time period of "prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

previous 92 days," is based on engineering judgment and is considered reasonable in view of the inaccessibility of the devices and the existence of other administrative controls ensuring that device misalignment is an unlikely possibility.

Condition A is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two PCIVs. For penetration flow paths with one PCIV, Condition C provides appropriate Required Actions.

Required Action A.2 is modified by a Note that applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

B.1

With one or more penetration flow paths with two PCIVs inoperable except for secondary containment bypass leakage rate, MSIV leakage rate, or hydrostatically tested lines leakage rate not within limits, either the inoperable PCIVs must be restored to OPERABLE status or the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1. C

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two PCIVs. For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

When one or more penetration flow paths with one PCIV inoperable except for secondary containment bypass leakage rate, MSIV leakage rate, or hydrostatically tested lines leakage rate not within limits, the inoperable valve must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration. Required Action C.1 must be completed within 4 hours for lines other than excess flow check valve (EFCV) lines and 12 hours for EFCV lines. The 4 hour Completion Time is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. The Completion Time of 12 hours is reasonable considering the mitigating effects of the small pipe diameter and restricting orifice, and the isolation boundary provided by the instrument. In the event the affected penetration is isolated in accordance with Required Action C.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident are isolated. This Required Action does not require any testing or valve manipulation. Rather, it involves verification that those devices outside containment and capable of potentially being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside primary containment" is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low. For the valves inside primary containment, the time period specified "prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days" is based on engineering judgement and is considered reasonable in view of the inaccessibility of the devices and other administrative controls ensuring that device misalignment is an unlikely possibility.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Condition C is modified by a Note indicating this Condition is applicable only to those penetration flow paths with only one PCIV. For penetration flow paths with two PCIVs, Conditions A and B provide the appropriate Required Actions. This Note is necessary since this Condition is written specifically to address those penetrations with a single PCIV.

Required Action C.2 is modified by a Note that applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

D.1

With the secondary containment bypass leakage rate, MSIV leakage rate, or hydrostatically tested lines leakage rate not within limit, the assumptions of the safety analysis may not be met. Therefore, the leakage must be restored to within limit within 4 hours (8 hours for main steam lines). Restoration can be accomplished by isolating the penetration that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. When a penetration is isolated, the leakage rate for the isolated penetration is assumed to be the actual pathway leakage through the isolation device. If two isolation devices are used to isolate the penetration, the leakage rate is assumed to be the lesser actual pathway leakage of the two devices. The 4 hour Completion Time is reasonable considering the time required to restore the leakage by isolating the penetration and the relative importance of leakage to the overall containment function. For main steam lines, an 8 hour Completion Time is allowed. The Completion Time of 8 hours for the main steam lines allows a period of time to restore the MSIVs to OPERABLE status given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown. C

(continued)

BASES (continued)

REFERENCES

1. FSAR, Chapter 6.2.
2. FSAR, Section 15.2.4.
3. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
4. Licensee Controlled Specifications Manual.

BASES

ACTIONS

A.1 (continued)

72 hours is allowed to restore at least one of the inoperable vacuum breakers to OPERABLE status so that plant conditions are consistent with those assumed for the design basis analysis. The 72 hour Completion Time is considered acceptable due to the low probability of an event in which the remaining vacuum breaker capability would not be adequate.

B.1

With one or more vacuum breakers with one disk not closed, communication between the drywell and suppression chamber airspace could occur, and, as a result, there is the potential for primary containment overpressurization due to this bypass leakage if a LOCA were to occur. Therefore, the open vacuum breaker disk must be closed. 72 hours is allowed to close the vacuum breaker due to the redundant capability afforded by the other vacuum breaker disk, (the fact that the other disk is closed), and the low probability of an event that would pressurize primary containment. If vacuum breaker position indication is not reliable, an alternate method of verifying that the vacuum breakers are closed is to verify that a differential pressure of ≥ 0.5 psid between the suppression chamber and drywell is maintained for 1 hour without makeup. As Noted, separate Condition entry is allowed for each vacuum breaker.

C.1

With one or more vacuum breakers with two disks not closed, this allows communication between the drywell and suppression chamber, and, as a result, there is the potential for primary containment overpressurization due to this bypass leakage if a LOCA were to occur. Therefore, one open vacuum breaker disk must be closed. A short time is allowed to close one of the vacuum breaker disks due to the low probability of an event that would pressurize primary containment. If vacuum breaker position indication is not reliable, an alternate method of verifying that the vacuum breaker disks are closed is to verify that a differential pressure of ≥ 0.5 psid between the suppression chamber and

(continued)

BASES

ACTIONS

C.1 (continued)

drywell is maintained for 1 hour without makeup. The required 2 hour Completion Time is considered adequate to perform this test. | C

D.1 and D.2

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are 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 3.6.1.7.1

Each vacuum breaker is verified closed (except when the vacuum breaker is performing its intended design function) to ensure that this potential large bypass leakage path is not present. This Surveillance is performed by observing the vacuum breaker position indication or by verifying that a differential pressure of ≥ 0.5 psid between the suppression chamber and drywell is maintained for 1 hour without makeup. The 14 day Frequency is based on engineering judgment, is considered adequate in view of other indications of vacuum breaker status available to operations personnel, and has been shown to be acceptable through operating experience.

A Note is added to this SR which allows suppression chamber-to-drywell vacuum breakers opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods of opening vacuum breakers are controlled by plant procedures and do not represent inoperable vacuum breakers.

SR 3.6.1.7.2

Each required vacuum breaker must be cycled to ensure that it opens adequately to perform its design function and returns to the fully closed position. This ensures that the

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

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

SURVEILLANCE REQUIREMENTS

SR 3.6.2.3.1

Verifying the correct alignment for manual, power operated, and automatic valves, in the RHR suppression pool cooling mode flow path provides assurance that the proper flow path exists for system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to being locked, sealed, or secured. A valve is also allowed to be in the nonaccident position, provided it can be aligned to the accident position within the time assumed in the accident analysis. This is acceptable, since the RHR suppression pool cooling mode is manually initiated. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Frequency of 31 days is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the probability of an event requiring initiation of the system is low, and the system is a manually initiated system. This Frequency has been shown to be acceptable, based on operating experience.

SR 3.6.2.3.2

Verifying each RHR pump develops a flow rate ≥ 7100 gpm, while operating in the suppression pool cooling mode with flow through the associated heat exchanger, ensures that the primary containment peak pressure and temperature can be

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.6.2.3.2 (continued) maintained below the design limits during a DBA (Ref. 2). The normal test of centrifugal pump performance required by ASME Section XI (Ref. 4) is covered by the requirements of LCO 3.5.1, "ECCS—Operating." Such inservice tests confirm component OPERABILITY, and detect incipient failures by indicating abnormal performance. The Frequency of this SR is in accordance with the Inservice Testing Program.

REFERENCES

1. FSAR, Section 6.2.1.1.3.5.
2. FSAR, Section 6.2.2.3.
3. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
4. ASME, Boiler and Pressure Vessel Code, Section XI.

BASES

APPLICABILITY (continued)

In MODES 4 and 5, the OPERABILITY requirements of the SW System and UHS are determined by the systems they support, and therefore, the requirements are not the same for all facets of operation in MODES 4 and 5. Thus, the LCOs of the systems supported by the SW System and UHS will govern SW System and UHS OPERABILITY requirements in MODES 4 and 5.

ACTIONS

A.1

With average sediment depth in either or both spray ponds ≥ 0.5 and < 1.0 ft, water inventory is reduced such that the combined cooling capability of both spray ponds may be less than required for 30 days of operation after a LOCA. Therefore, action must be taken to restore average sediment depth to < 0.5 ft. The Completion Time of 30 days is based on engineering judgement and plant operating experience and takes into consideration the low probability of a design basis accident occurring in this time period.

B.1

If one SW subsystem is inoperable, it must be restored to OPERABLE status within 72 hours. With the unit in this condition, the remaining OPERABLE SW subsystem is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE SW subsystem could result in loss of SW function. The 72 hour Completion Time was developed taking into account the redundant capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

The Required Action is modified by two Notes indicating that the applicable Conditions of LCO 3.8.1, "AC Sources—Operating," and LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown," be entered and the Required Actions taken if the inoperable SW subsystem results in an inoperable DG or RHR shutdown cooling subsystem, respectively. This is in accordance with LCO 3.0.6 and ensures the proper actions are taken for these components.

(continued)

ATTACHMENT 1

Discussion and Bases for Changes

SGT System Description

The SGT system is described in Subsection 1.2.2.5.17 and Section 6.5.1 of the WNP-2 Final Safety Analysis Report (FSAR) and a simplified drawing of the system is included in Attachment 2 (Figure 1). The SGT system consists of two identical filter trains, designated A and B. Each train can take suction from the primary containment and the main steam isolation valve leakage control (MSLC) system and/or the reactor building 572 foot (ft) elevation. The SGT system can discharge either back to the reactor building 572 ft elevation or to the reactor building elevated release point. Each filter train consists of a filter unit, two fans, ductwork, and the associated valves. Either filter train may be considered as an installed spare with the other train being capable of providing the capacity necessary to perform post-accident secondary containment drawdown and reactor building exhaust cleanup functions. Moreover, the active system components in each filter train that are required for post-accident operation are redundant and configured in two subsystems to allow for lead/lag operation. The Train A subsystems are designated A1 and A2 and the Train B subsystems are designated B1 and B2. The major components within each subsystem are identified in Figure 1 and their associated divisional power is indicated by color coding (purple - Division 1; green - Division 2). The lead subsystem of each train is powered from a separate emergency diesel divisional bus (Division 1 or 2) than the lag subsystem. As indicated in Figure 1, the Train A lead subsystem is A1 and the lag subsystem is A2. For Train B, the lead subsystem is B2 and the lag subsystem is B1. [Note: The SGT fan suction valves are normally open and fed from the opposite divisional power source than the rest of their associated subsystem. This allows the redundant subsystem to be operated upon a loss of a divisional power source by ensuring that the fan suction valve of the failed subsystem has electrical power for closure to prevent backflow.] In the event that the lead subsystem in a train fails to establish proper air flow within a set time delay from an SGT system start signal, the lead subsystem will automatically shutdown and the lag subsystem will start. Thus, the lag subsystem within a train may be considered as a backup to the lead subsystem, with either subsystem being capable of supporting the associated train in the performance of its required functions. In post-accident situations, both filter trains of the SGT system automatically initiate or can be initiated manually from the main control room to achieve and maintain a pressure of at least 0.25 inch of vacuum water gauge on all surfaces of the secondary containment (from an initial pressure of 0 inches water gauge). Although both filter trains initiate, only one train is required for accident mitigation. The SGT system starts automatically on a high drywell pressure (1.88 psig), a reactor vessel low water level (Level 2; -58"), or a reactor building exhaust plenum high radiation (16.0 mr/hr) initiation signal. These initiation signals are collectively termed as a "FAZ" initiation. [Note: The indicated "FAZ" setpoints are the allowable values proposed for the ITS.] During post-accident operation, the SGT system is automatically aligned to take suction from the reactor building 572 ft elevation. The system processes the inlet air to remove the airborne particulate and gaseous activity from the air and then discharges the processed gaseous effluent to the reactor building elevated release point.

Each filter train contains (listed in sequence from inlet to outlet) a demister (moisture separator), two banks of electric heaters in series, a prefilter, a high efficiency particulate (HEPA) filter, an electric strip heater, an activated charcoal bed for iodine adsorption, a second electric strip

heater, a second activated charcoal bed for iodine adsorption, a second HEPA filter, and redundant instrumentation to measure temperature, humidity, and flow.

Each SGT filter train is capable of independently processing the air flow as follows:

> The demister removes water droplets from the inlet air and the two banks of heaters (one powered from the lead fan power division and one powered from the lag fan power division) maintain the relative humidity below 70% to ensure an SGT filtration efficiency of 99%. The medium efficiency prefilter in combination with the HEPA prefilter remove virtually all of the particulate matter from the inlet air and the two in-series charcoal beds adsorb radioactive iodine. The plenum of each charcoal bed contains an electric strip heater which maintains the charcoal above the atmospheric dewpoint to prevent condensation while the SGT system is in standby. The strip heaters are not required for successful post-accident operation of the SGT system. The HEPA afterfilter traps charcoal particles that may escape the charcoal adsorbers. At the discharge of each filter unit are two 100% capacity fans (one lead fan and one lag fan) in parallel. These fans provide the air flow through the filter unit. On the inlet side of each fan is a motor-operated butterfly valve and an electro-hydraulically-operated variable inlet vane damper (vortex damper). The vortex dampers are controlled to achieve and maintain at least 0.25 inch of vacuum water gauge differential pressure on all surfaces of secondary containment.

Required System/Component Safety Function

The SGT system acts as part of secondary containment to minimize and control airborne radiological releases from the plant to within 10 CFR 100 guidelines and 10 CFR 50, Appendix A, General Design Criteria 19 limits. Unfiltered release of primary containment leakage following a severe accident or the release of radioactive gases and particulates resulting from accidents outside primary containment (e.g., fuel handling accident, instrument line breaks) are prevented by achieving and maintaining a secondary containment pressure of at least 0.25 inch vacuum water gauge with respect to atmospheric pressure and by filtering the effluent gases from secondary containment through a 99% efficient filter train. The basis for the 0.25 inch of vacuum water gauge requirement comes from Section 6.2.3 of NUREG-0800, "Standard Review Plan," and is the point at which credit for SGT charcoal adsorption is allowed. A secondary function of the SGT system is to filter the purge exhaust from primary containment whenever radiation levels within the primary containment exceed acceptable levels for direct purge to the environment via the reactor building exhaust system.

To demonstrate that the secondary containment and SGT system designs will maintain radioactive releases within the 10 CFR 100 guidelines and 10 CFR 50, Appendix A, General Design Criteria 19 limits, a post-accident dose assessment is performed using the source term criteria outlined in Regulatory Guide 1.3, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Boiling Water Reactors." The designs must accommodate a post-accident single failure such that secondary containment and the SGT system remain operable. In addition, certain plant specific parameters, such as SGT

capacity, secondary containment in-leakage, outside meteorological conditions, secondary containment heat loads, available cooling capacity, emergency diesel start time and loading sequence, and drawdown time for the limiting secondary containment elevation must be considered in the designs and dose assessments. The time for secondary containment to reach 0.25 inch of vacuum water gauge on all surfaces is referred to as secondary containment drawdown time and is one of the major factors influencing offsite and control room radiation doses. The previous design basis requirement for SGT performance was to drawdown the secondary containment from 0 inches water gauge to 0.25 inch of vacuum water gauge differential pressure within 2 minutes of a post-accident initiation (FSAR Tables 6.9-28 and 29: 150 seconds - 34 seconds $\approx$ 2 minutes).

<u>Background</u>

In 1988, the Supply System discovered that original assumptions used to evaluate secondary containment drawdown time were nonconservative. Certain wind and low temperature conditions could reduce the capability to achieve the required negative differential pressure in secondary containment following a Loss of Coolant Accident (LOCA) coincident with an assumed failure of one SGT system filter train. This condition was reported to the NRC in LERs 88-023, 88-023-01, and 89-040 (References 1, 2, and 4) and also as a USQ (Reference 3). WNP-2 Nonconformance Reports (NCRs) 288-0356 and 288-0357 originally documented the problem, and a JCO was developed to address the operability issues.

Revisions 0 and 1 of the JCO addressed the original problem concerning the capability of the SGT system to effectively perform its safety function under all postulated post-accident conditions, including consideration of adverse environmental conditions. Revisions 2 and 3 of the JCO were required to address new issues identified concerning instrument calibration accuracy and setpoint error. Revision 4 addressed the potential for the standby service water (SW) spray pond temperature to reach 32°F (analysis previously showed that SW temperature impacts secondary containment drawdown time). Revision 5 (the lastest revision) addressed reduced room cooler performance due to fouling (down to 65% efficiency) and also documented resolution of a concern regarding the single failure of the SGT system inlet valves.

The current design basis for the SGT system is contained in Revision 5 of the JCO. Consistent with the 10 CFR 50.59 process, NRC approval was not required for the changes to the JCO that were incorporated subsequent to issuance of the Safety Evaluation Report (SER) by the NRC staff for Revision 0 of the JCO (Reference 6). Table 1 of the JCO (Attachment 4) shows the evolution of the key parameters used for the current accident analyses. Assuming a worst case single failure and 95% wind and temperature meteorology, the current limitation on the SGT system requires that it be capable of drawing down secondary containment to a pressure of 0.25 inch of vacuum water gauge within 10 minutes after a post-accident actuation initiation. It has also been shown that sufficient margin exists to maintain the 10 minute drawdown time even when considering transfer from the lead to lag subsystem based on the current JCO secondary containment leakage limit of 1475 cfm. The JCO has established that the offsite and control room doses would remain within the 10 CFR 100 guidelines as well as the 10 CFR 50, Appendix A, General Design Criteria 19 limits.

As previously stated, this Technical Specification amendment request is intended, not only to justify the proposed changes to the Technical Specifications, but also to document the resolution of related issues identified in the JCO. Therefore, in addition to a copy of Revision 5 of the JCO, Attachment 4 also includes a summary of the JCO closeout items (identified from all five JCO revisions) and references to the associated closure documents and completion dates where appropriate.

On February 6, 1995, the Supply System met with the NRC (Reference 13) to discuss a proposed new design basis and associated changes to the Technical Specifications that will ultimately resolve the USQ identified in Reference 3. The proposal was based on significant additional analyses using the GOTHIC and PADD computer codes. The results of these new analyses were not necessary to address current secondary containment and SGT system operability, and therefore, were not incorporated into Revision 5 of the JCO which includes the current design basis. In essence, the analytical changes to the design basis are as follows:

- Increase the minimum SGT system flow rate from 4457 cfm to 5000 cfm. This represents an increase from the original design basis (4457 cfm) but a decrease from Revision 5 of the JCO (5385 cfm).

- Increase the time allowed to drawdown secondary containment from 0 inches water gauge to 0.25 inch of vacuum water gauge from 2 minutes to 20 minutes. No SGT filtering is credited for the first 20 minutes post-accident.

- Credit 40% mixing within the secondary containment.

- Increase the allowable secondary containment bypass leakage from 0.74 scfm to 18 scfm.

- Restrict environmental conditions to 95% wind and temperature meteorological data.

Using the GOTHIC and PADD computer codes and assuming the new design basis, it has been shown that the offsite and control room doses remain within the 10 CFR 100 guidelines and the 10 CFR 50, Appendix A, General Design Criteria 19 limits. The new design basis has been reviewed to ensure compliance with the applicable design criteria and requirements, including 10 CFR 50, Appendix A, Criterion 41 and 10 CFR 50, Appendix B, Criterion III.

The balance of this attachment provides justification for the proposed changes to the secondary containment and SGT system Technical Specifications. As discussed in the cover letter, Attachments 3A and 3B provide marked up copies of the affected Technical Specifications and the supporting Bases pages, indicating the changes to the CTS and ITS, respectively.

Proposed Change

(i) *Enhance the secondary containment integrity surveillance requirements by establishing an acceptable operating region as a function of secondary containment differential pressure and SGT system flow.*

Basis for Proposed Change

Currently, CTS Surveillance Requirement 4.6.5.1.c.1 and ITS Surveillance Requirement SR 3.6.4.1.4 require secondary containment to be drawn down to greater than or equal to 0.25 inch of vacuum water gauge in less than or equal to 120 seconds. The proposed change would increase the drawdown time from 120 seconds to 20 minutes and establish acceptable drawdown as a function of secondary containment differential pressure and SGT flow rate. A curve similar to Figure 4 of Attachment 2 will be used to determine the acceptable region for secondary containment differential pressure versus SGT flow rate. The basis for the curve is included in the discussion of the changes to CTS Surveillance Requirement 4.6.5.1.c.2 and ITS Surveillance Requirement SR 3.6.4.1.5. The supporting drawdown analysis takes into account the meteorological conditions, initial secondary containment temperature and humidity, standby service water (SW) temperature, and the worst case single failure. Based on post-accident transient analyses, SGT system flow rate must be greater than or equal to 5000 cfm within 2 minutes of the initiation signal. This time includes the time for the emergency diesel generator to start, the SGT start sequence to occur, and an automatic swap-over to the lag subsystem assuming a failure of the lead subsystem. Verification of the capability of the SGT system to achieve 5000 cfm within 2 minutes has been included in the system filter testing requirements.

The post-accident short term and long term transient response analyses have been performed using GOTHIC. As indicated in the cover letter, Attachment 5 contains model element details and background information pertaining to GOTHIC. Based on benchmarking analyses performed to date, the use of GOTHIC for the secondary containment drawdown analyses is appropriate. The conditions and assumptions used in the analyses are consistent with the proposed changes to the design bases and the Technical Specifications and assure conservative evaluation of the performance of secondary containment and the SGT system. The short term transient response of the secondary containment atmosphere has been analyzed for 30 minutes post accident, during which time a steady-state negative differential pressure has been established. The long term transient response analysis applies from 30 minutes through 6 months, during which time the steady-state temperature and humidity are functions of the operating systems and meteorological conditions. The chronological sequence of events in secondary containment during the short term post-accident period are as follows:

Post-Accident Time		Events in Secondary Containment
0 seconds	-	Design basis event.
	-	Loss of offsite power.
	-	All normal operating equipment including normal lights cease to function.

	-	Secondary containment pressure equalized with environment (0 inch water gauge).
	-	Secondary containment at 0 inch water gauge, 50°F, and 0% relative humidity (R.H.).
15 seconds	-	Emergency power on (automatic).
	-	Emergency building lighting on (automatic).
	-	High Pressure Core Spray (HPCS) system starts.
	-	Division 1 and 2 diesel loading sequence starts.
120 seconds	-	SGT system starts (flowrate ≥ 5000 cfm).
130 seconds	-	One train of SW on (automatic).
≤ 20 minutes	-	Secondary containment pressure reaches 0.25 inch of vacuum water gauge (SGT filtration credited).
30 minutes	-	Secondary containment stabilizes at ≥ 0.25 inch of vacuum water gauge.

The equipment loading sequence is shown in Tables 8.3-1 through 8.3-6 of the WNP-2 FSAR.

The short term pressure transient analysis results are presented in Figure 2 of Attachment 2. For the various atmospheric conditions considered in this analysis, the winter case yielded a longer drawdown time than the summer case. Using the site specific joint frequency temperature and wind meteorological data accumulated over a 6 year period (01/01/84 - 01/01/90), parametric analyses were performed to define the effects of temperature and wind on the SGT system drawdown time and secondary containment leakage.

From the above parametric analyses, a secondary containment and SGT system design basis meteorology was defined which envelopes 95% of the joint frequency temperature and wind at the site. Figure 3 of Attachment 2 provides the design basis meteorology.

Secondary containment leakage is established in the analysis for static meteorological conditions at 2240 cfm. Wind and temperature effects act to increase secondary containment in-leakage beyond 2240 cfm to maximum leakage at bounding design basis meteorological conditions. For the most limiting winter case, the analysis results in a time of approximately 11.9 minutes to drawdown all surfaces of secondary containment to 0.25 inch of vacuum water gauge differential pressure. This most limiting winter case was analyzed for the following conditions: initial secondary containment temperature is 50°F, atmospheric temperature is 0°F with no wind, spray pond temperature is 77°F, Division 2 power is used (assuming Division 1 power has failed or is not available), and one SGT system train is in operation at a flow rate of 5000 cfm within 2 minutes of the transient.

The most limiting summer case was analyzed for the following conditions: initial secondary containment temperature is 75°F, atmospheric temperature is 94°F with no wind, spray pond temperature is 75°F, Division 2 power is used (assuming Division 1 power has failed or is not available), and one SGT system train is in operation at a flow rate of 5000 cfm within 2 minutes of the transient. It takes approximately 8.8 minutes to drawdown all surfaces of the secondary containment to at least 0.25 inch of vacuum water gauge differential pressure in this limiting summer case.

The short term transient analysis was developed using two models described as follows:

Static Meteorology Model: The purpose of this model is to determine leakage path characteristics consistent with meteorology that produces uniform differential pressure across all surfaces of the secondary containment boundary. The secondary containment leakage was set at 2240 cfm by adjusting the in-leakage flow area to achieve 0.25 inch of vacuum water gauge on all surfaces with a 60/40% flow split. The most limiting conditions for winter are achieved by placing 60% of the leakage potential for secondary containment at the ground level release point (railroad bay door) and 40% at the elevated release point (606 ft elevation). For summer, the most limiting conditions are achieved by placing 40% of the leakage potential at the ground level release area and 60% at the elevated release area. This 60/40% leakage split was discussed with J.A. Kudrick, representing the NRC Containment Systems Branch, in a January 16, 1990 meeting between the Supply System and NRC staffs.

Drawdown Model: This model uses the leakage area defined by the static model for winter and summer conditions and the 95% meteorological data considered as the bounding weather conditions. The drawdown model is used to determine the time to reach 0.25 inch of vacuum water gauge differential pressure across all secondary containment surfaces. In addition, heat transfer between primary containment and secondary containment, secondary containment heat loads, room coolers, and thermal conductors (concrete walls, etc.) have been added to the drawdown model.

The conditions and assumptions for the short term transient analysis are discussed in detail below.

Static Meteorology Model:

1. The conditions are set at 68°F, 14.696 psia, a relative humidity of 0%, and standard temperature and pressure (STP). The atmospheric pressure is defined at ground level, 441 ft elevation.

2. Primary containment to secondary containment leakage is considered to be negligible. The maximum allowable leakage rate is equal to 4 scfm (L_a), and is considered small compared to the SGT system flow.

3. Heat transfer between each secondary containment floor elevation is ignored.

4. Each floor elevation in secondary containment is modeled separately.

5. Leakage into and out of the secondary containment prior to SGT system start is not allowed.

6. Secondary containment heat loads, Emergency Core Cooling System (ECCS) pump room coolers, and the normal lighting loads are not considered.

7. Secondary containment is assumed to leak at the 606 ft elevation (refuel floor) and 441 ft elevation (railroad bay door). The leakage area is defined such that, at 2240 cfm and static conditions, secondary containment is at 0.25 inch of vacuum water gauge on all surfaces. The static model is utilized to determine the ground level (441 ft elevation) and the elevated (606 ft elevation) leakage areas. The leakage areas are based on 60% ground and 40% elevated under winter conditions, and 40% ground and 60% elevated under summer conditions (±1% tolerance). The 60/40% leakage split conservatively places the greatest potential for leakage in the location which results in the longest drawdown time for each of the summer and winter meteorological conditions.

8. The SGT system performance characteristics have been included in the model.

Drawdown Model:

The drawdown model of secondary containment is used to determine the time to reach 0.25 inch of vacuum water gauge differential pressure on all surfaces of secondary containment taking into account wind and temperature effects. The drawdown model uses the leakage path characteristics defined by the static model for summer and winter conditions. Additional drawdown model conditions and assumptions are as follows:

1. Primary containment to secondary containment leakage is considered to be negligible. The maximum allowable leakage rate is equal to 4 scfm (L_a), and is considered small compared to the SGT system flow.

2. Heat loads for Motor Control Center (MCC) rooms and the Fuel Pool Cooling (FPC) heat exchanger room are modeled inside their respective rooms along with the available room coolers. Heat transfer through the room walls is included.

3. Heat transfer from primary containment to secondary containment is included.

4. Heat transfer through the secondary containment floors is included.

5. Heat transfer from one pump room to another (i.e. HPCS room to Low Pressure Core Spray [LPCS] room) is neglected. Each room has coolers and their performance is modeled as a function of room temperature and SW temperature.

6. Heat transfer from the outside environment to secondary containment is included for the summer cases but is neglected in the winter cases. This results in the most conservative drawdown times for both cases.

7. For the winter cases, the initial differential pressure across secondary containment is equalized at the 441 ft elevation. However, for the summer case, the initial pressure differential across the secondary containment is equalized at the 606 ft elevation. These assumptions lead to the longest drawdown times.

8. Conceptually, the primary containment structure could expand because the interior is exposed to the peak accident pressure. However, the decrease in the volume of secondary containment due to the expansion of the primary containment structure is small relative to the overall volume of secondary containment (approximately $3.5x10^6$ ft^3). Therefore, the compressive effect of the primary containment expansion on the secondary containment atmosphere has been neglected in this analysis.

9. Normal heat loads are reduced to zero after one hour on a linear basis. Also, the normal heat loads are assumed to be split evenly between the 471 ft, 501 ft, 522 ft, 548 ft, 572 ft, and 606 ft elevations.

10. One division of SW is available 2.17 minutes following the accident initiation and coincident loss of offsite power. HPCS is actually available 1 minute into the transient but is modeled to start at 2.17 minutes.

11. A 50% efficiency factor is applied to the room coolers.

12. Initially, secondary containment is full of dry air (i.e., R.H. at 0%). This assumption leads to conservative drawdown times because humid air is less dense than dry air. Thus, the drawdown time to evacuate dry air from secondary containment is somewhat longer than would be required for humid air.

13. No out-leakage is allowed through secondary containment.

The long term transient analysis was performed to establish post-accident temperature and humidity profiles for secondary containment consistent with the guidelines of NUREG-0800 Standard Review Plan (SRP) 6.2.3.II.1. The long term analysis includes both winter and summer cases, each with a duration of 6 months. This analysis is essentially an extension of the short term drawdown analysis with some modifications to the drawdown model in order to more conservatively predict the long term responses of secondary containment. The drawdown requirement of 0.25 inch of vacuum water gauge differential pressure on all surfaces of secondary containment was reached in approximately 300 seconds for the long term analysis, which is less than the drawdown times established in the short term transient analyses. The shorter duration drawdown time for the long term analysis is primarily due to using a smaller in-leakage rate, a conservative approach for obtaining the peak temperature and humidity values.

No further discussion of the long term analysis is included in this submittal since the 300 second drawdown time to 0.25 inch of vacuum water gauge is bounded by the short term analysis drawdown times for both the winter and summer cases (11.9 and 8.8 minutes, respectively). After secondary containment is initially drawn down to the differential pressure of 0.25 inch of vacuum water gauge, the differential pressure remains below this value for the duration of the long term transient analysis.

In summary, for the various atmospheric conditions considered in the secondary containment drawdown analyses, the short term winter cases yielded the longest drawdown times. Based on the analyses, the most limiting winter case occurs when the initial temperature in secondary containment is 50°F, the atmospheric temperature is 0°F with no wind, the SW spray pond temperature is 77°F, only Division 2 diesel power is available (the Division 1 diesel failed), and only one SGT train is in operation. For this most limiting winter case, the analysis results in a time of approximately 11.9 minutes to drawdown secondary containment to 0.25 inch of vacuum water gauge differential pressure when secondary containment leakage is 2240 cfm. The 20 minute drawdown time proposed for the surveillance requirement conservatively bounds the drawdown analyses results and is conservative for offsite and control room dose calculations. In all of the cases considered in the drawdown analyses, SGT system flow rate is assumed to achieve 5000 cfm within 2 minutes from the start of the transient. This start time allows sufficient margin for the diesel to start and the SGT system automatic valve alignments and start sequence to occur, including the delay time associated with an automatic transfer from the lead subsystem to the lag subsystem if necessary. Verification of the capability of the SGT system to achieve 5000 cfm within 2 minutes has been included in the system filter testing surveillance requirements. See Table 1 of Attachment 2 for a summary and comparison (with previous design basis values) of the key design basis parameters used in the analyses supporting the proposed changes to the secondary containment and SGT system surveillance requirements. The changes from the JCO, Revision 5, design basis parameters are only analytical changes that do not result in any physical changes to plant equipment or changes to equipment functions or setpoints.

Currently, CTS Surveillance Requirement 4.6.5.1.c.2 and ITS Surveillance Requirement SR 3.6.4.1.5 require secondary containment to be drawn down to at least 0.25 inch of vacuum water gauge at an SGT system flow rate not exceeding 2240 cfm. This surveillance requirement verifies secondary containment integrity by ensuring that secondary containment in-leakage does not exceed a value (2240 cfm) that could prevent acceptable drawdown (0.25 inch of vacuum water gauge). This surveillance requirement can be satisfied by verifying that the differential pressure is at a greater vacuum (larger negative pressure) than 0.25 inch of vacuum water gauge when measured at any SGT flow rate greater than 2240 cfm and corrected for the effects of outside wind and temperature. Based on analysis, it has been determined that the secondary containment differential pressure associated with SGT flow rate is a combination of linear and quadratic in-leakage relationships. The differential pressure is primarily a function of the seams in the secondary containment superstructure and leakage through doorways. The differential pressure generally increases linearly with increasing flow through the seams and doorways. An equation has been derived to provide a basis for satisfying the secondary containment in-leakage limits. The equation is as follows (Flow in cfm and ΔP in inches water gauge):

$$\textbf{Flow} = 1988.3 * \Delta P + 3485.85 * \sqrt{\Delta P}$$

This equation is derived from correlated performance curves with the constant for the square root term increased such that a differential pressure of 0.25 inch of vacuum water gauge would result in a flow rate of 2240 cfm. The constant associated with the square root term was conservatively increased to account for increased leakage which would generally result in quadratic losses rather than linear losses. Figure 4 of Attachment 2 is the curve generated by the above equation and illustrates the acceptable region for secondary containment differential pressure versus SGT flow rate. A representative figure will be included in the appropriate implementing procedures.

The changes to the secondary containment post-accident response analysis described above also impacts the design basis dose analysis. In the dose analysis, less than or equal to 20 minutes is credited for the SGT system to drawdown secondary containment to a differential pressure of 0.25 inch of vacuum water gauge. The original design basis secondary containment response analysis assumed approximately 2 minutes for the SGT system to drawdown secondary containment to 0.25 inch of vacuum water gauge. This increase in the design basis drawdown time has been incorporated into the dose analysis assumptions such that no SGT filtering is credited for the first 20 minutes post-accident. The drawdown time assumed for the dose analysis conservatively bounds the 11.9 minute drawdown time established in the drawdown analyses. Additional changes to the dose analysis assumptions associated with secondary containment include an increase in the bypass leakage from 0.74 scfh to 18 scfh and the crediting of mixing within secondary containment in accordance with Regulatory Guide 1.3. The 40% mixing credit was discussed with the NRC staff in the February 6, 1995 meeting (Reference 13) and is justified based on the results of site specific tracer analysis. The previous design basis credited no mixing within secondary containment. As previously discussed, the PADD computer code was used for the post-accident dose analysis. This code is maintained under the Quality Assurance (QA) program of ERIN Engineering and has been compared and validated against General Electric (GE) methodology. The changes to the secondary containment design basis have been incorporated into the PADD dose analysis code and the results show that offsite and control room doses remain within the 10 CFR 100 guidelines and the 10 CFR 50, Appendix A, General Design Criteria 19 limits.

A comparison of the revised dose values with the original safety evaluation values and the 10 CFR 100 guidelines and 10 CFR 50, Appendix A, General Design Criteria 19 limits are provided in Table 2 of Amendment 2. The control room and low population zone (LPZ) doses are for 30 days duration and the exclusion area boundary (EAB) doses are for a 2 hour duration. As indicated in the Table, the new dose analysis results in an increase in calculated thyroid doses but a decrease in whole body doses. The LPZ is defined as all land within a 3 mile radius of the plant site and 0 persons reside within this area. The nearest residence is 4.1 miles from the plant site. There are no schools or hospitals within 5 miles of the plant site and the nearest population center is at 12 miles. Considering the low population density in the area immediately surrounding the plant site, the increase in thyroid dose will have a small impact on the health and safety of the public.

Proposed Change

(ii) *Revise the secondary containment and SGT system Technical Specifications to more accurately reflect the existing design which consists of 2 filter trains and 4 divisional subsystems.*

Basis for Proposed Change

Currently, CTS 4.6.5.1 and 3/4.6.5.3 and ITS 3.6.4.1 and 3.6.4.3 do not effectively reflect the existing SGT system design. As previously described, the SGT system consists of 2 filter trains (A and B), with each train having two subsystems. The active system components in each filter train, including their start logic, are redundant and configured in a lead/lag operational design. As indicated in Figure 1 of Attachment 2, the Train A lead subsystem is A1 and the lag subsystem is A2. For Train B, the lead subsystem is B2 and the lag subsystem is B1. In post-accident situations, a "FAZ" signal is sent independently to the lead and lag subsystems of each SGT filter train and the lead subsystem in each train will automatically start. In the event that the lead subsystem in a train fails to establish proper air flow within a set time delay from an SGT system start signal, the lead subsystem will automatically shutdown and the lag subsystem will start. Based on post-accident transient analyses, SGT system flow rate must be greater than or equal to 5000 cfm within 2 minutes of the initiation signal. This will ensure secondary containment drawdown from 0 inches water gauge to 0.25 inch of vacuum water gauge differential pressure within 20 minutes when secondary containment static leakage does not exceed 2240 cfm. The 2 minute start time allows sufficient margin for the diesel to start and the SGT system automatic valve alignments and start sequence to occur, including the delay time associated with an automatic transfer from the lead subsystem to the lag subsystem if necessary. Thus, the lag subsystem within a train may be considered as a backup to the lead subsystem, with either subsystem being capable of supporting the associated train in the performance of its required functions.

Based on the SGT system design capabilities, the inoperability of both lead or both lag subsystems (i.e., one subsystem is inoperable in each filter train and the subsystems have redundant divisional affiliations) has no effect on post-accident operation since both filter trains remain available with each train being powered from a divisionally separated bus. Thus, the Technical Specification requirements are met in this condition. However, if 2 subsystems from the same division are inoperable or either filter train is inoperable, or any 3 subsystems are inoperable, only one filter train with one divisional subsystem can be credited. This condition and the condition where all four subsystems are inoperable meet the intent of the current Technical Specification Actions and the proposed revision specifies the appropriate current Technical Specification Actions to be completed. The proposed revision also clarifies the surveillance requirements and Bases to allow credit for the existing design while still ensuring secondary containment and SGT system operability. Therefore, this proposed change is a clarification of the existing design that provides clearer direction for operations personnel and satisfies the intent of the current Technical Specification requirements.

Proposed Change

(iii) *Revise the SGT system surveillance requirements to reflect the change in system flow rate from 4457 cfm to 5000 cfm.*

Basis for Proposed Change

Currently, CTS Surveillance Requirements 4.6.5.3.b.1, d.1, e, and f and ITS Ventilation Filter Testing Program Requirements 5.5.7.2.a, b, and d specify an SGT system flow rate of 4457 cfm (nominal) for filter testing. As previously discussed, the secondary containment drawdown analysis assumes the SGT system flow rate to be 5000 cfm within 2 minutes of an accident start signal.. This flow rate is an increase from the previous design basis value of 4457 cfm, but is a decrease from the JCO value of 5385 cfm. The new 5000 cfm value for SGT system flow rate has been evaluated to ensure that it is high enough to satisfy the secondary containment drawdown requirements and low enough to provide adequate atmosphere residence time for 99% filter efficiency credit in the design basis analyses. The change to the SGT system flow rate is an analytical change only. No changes to plant equipment or equipment setpoints are required. SGT system flow rate for filter test purposes is 4500 to 5500 cfm which complies with American National Standards Institute (ANSI) Standard N510-1989, "Testing of Nuclear Air Treatment Systems."

The credited flow rate is being reduced from the JCO value to provide additional margin. The current setpoint calculation methodology considers actual plant calibration data to determine total instrument uncertainties, including drift. The method is based on American National Standards Institute/Instrument Society of America (ANSI/ISA) Standard S67.04-1988, "Setpoints for Nuclear Safety-Related Instrumentation," and guidelines in ISA draft Recommended Practice RP67.04, "Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation." Specifically, the method includes:

- definition of loop to be analyzed;
- determination of the analytical limit;
- determination of the normal and accident environmental conditions for each loop component, including but not limited to pressure, humidity, seismic, temperature, and radiation;
- determination of the normal and accident environmental condition effects;
- determination of drift effects;
- combination of the effect terms; and
- determination of setting range.

Based on the secondary containment accident response analyses, verifying that an SGT fan flow rate of 5000 cfm is achieved within 2 minutes of a start signal ensures that secondary containment can be drawn down to 0.25 inch of vacuum water gauge differential pressure within approximately 11.9 minutes. This time is within the post-accident dose analysis 20 minute drawdown time assumption. Satisfying the 20 minute drawdown requirement allows credit for SGT system filtration of post-accident radioactive gases and particulates released to secondary containment and ensures that offsite and control room doses are maintained within the 10 CFR 100 guidelines and the 10 CFR 50, Appendix A, General Design Criteria 19 limits. Since an SGT fan flow rate of 5000 cfm is used in the design basis analyses for both the drawdown and filtration capabilities of the SGT system, it is appropriate that this same flow rate value be used to demonstrate both of these design basis capabilities. Therefore, the surveillance requirements demonstrating SGT system filtration capability have been revised to specify a system flow rate of 5000 cfm.

Proposed Change

(iv) Delete the existing requirement to maintain the secondary containment at ≥ 0.25 inch of vacuum water gauge at all times (i.e., during normal operation with the nonsafety-related secondary containment ventilation system).

Basis for Proposed Change

Currently, CTS Surveillance Requirement 4.6.5.1.a requires a verification every 24 hours that the pressure within secondary containment is ≤ 0.25 inch of vacuum water gauge. ITS SR 3.6.4.1.1 requires a similar test; however, the NUREG-1434, Revision 1, SR 3.6.4.1.1 requirement is bracketed. This requirement is bracketed in the NUREG because to maintain ≥ 0.25 inch of vacuum water gauge at all times is not required by all BWRs as an initial condition of the accident analysis. As previously discussed, the accident analysis assumes the secondary containment is at 0 inch water gauge at the start of the accident and is drawn down to 0.25 inch of vacuum water gauge within 20 minutes. In addition, failure to maintain 0.25 inch of vacuum water gauge with the nonsafety-related secondary containment ventilation system is not necessarily indicative of an inoperable secondary containment, nor does maintaining 0.25 inch of vacuum water gauge ensure the secondary containment is operable. In the event that the normal secondary containment ventilation system is secured, secondary containment could become pressurized such that the maximum accident design basis pressure of 0 inch water gauge on all surfaces of secondary containment is exceeded. Therefore, when the normal secondary containment ventilation system is secured, action will be taken in accordance with the current Limiting Conditions for Operation (LCOs) or the SGT system will be started to ensure that design basis accident mitigation assumptions remain valid. Action in accordance with the current LCOs or starting the SGT system will also ensure that secondary containment effluent is monitored during normal plant operation. The FSAR will describe that secondary containment is normally maintained at a negative pressure, and any additional changes to the FSAR related to this design will be controlled by the provisions of 10 CFR 50.59. Therefore, since the accident assumptions are continuing to be met, the Surveillance Requirement verifying normal secondary containment vacuum has been deleted.

ATTACHMENT 2

Figures and Tables

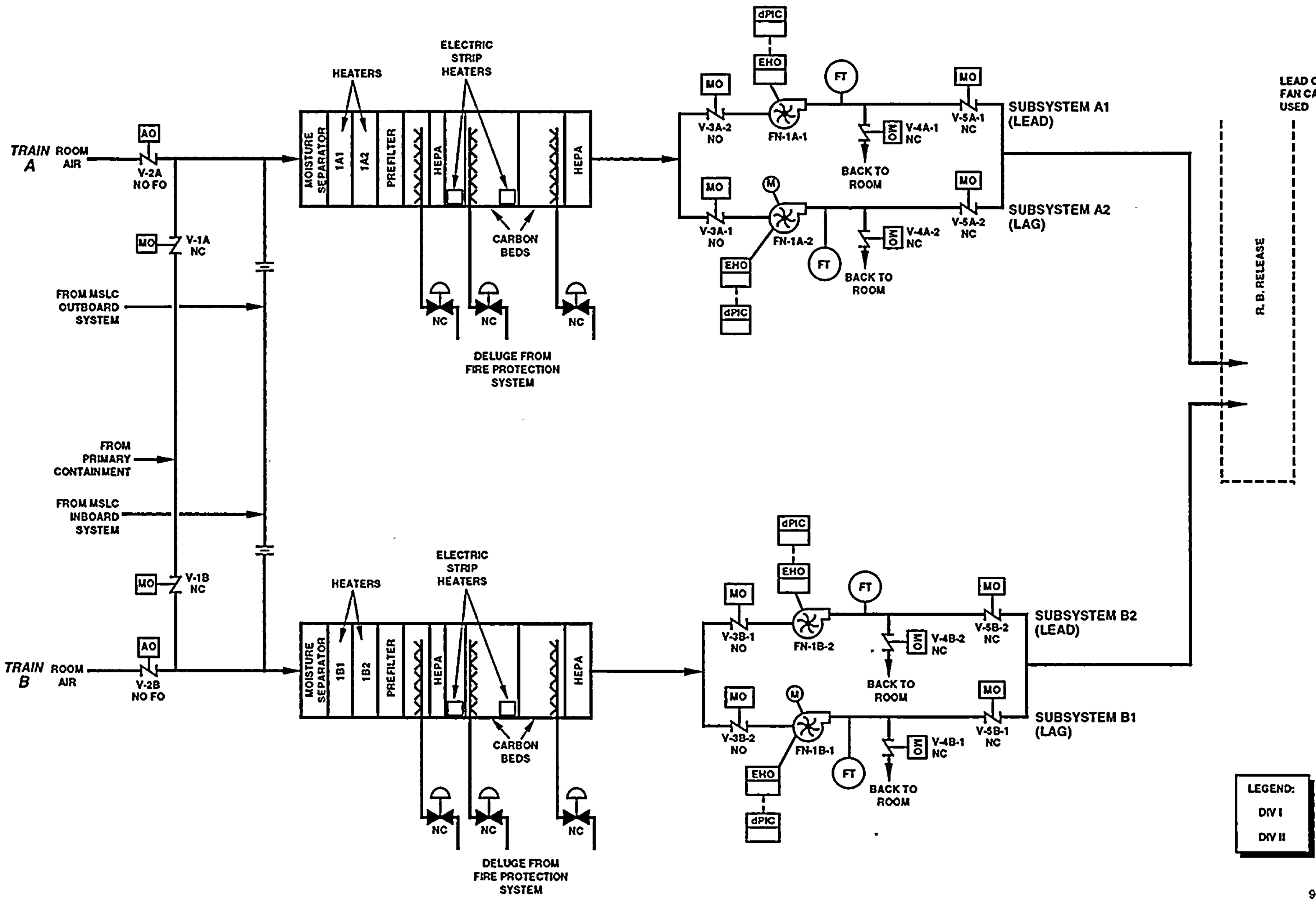

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FIGURE 1. STANDBY GAS TREATMENT SYSTEM

Table 1

Comparison of Key SGT Parameters

KEY PARAMETERS	ORIGINAL DESIGN	JCO Rev. 0 & Rev. 1	JCO Rev. 2 & Rev. 3	JCO Rev. 4	JCO Rev. 5	PROPOSED DESIGN
Regulatory Guide 1.3 Release Assumptions	yes	yes	yes	yes	yes	yes
Secondary containment Reactor Building Pressure	-0.25" w.g.	-0.25" w.g. (worst location)	-0.25" w.g. (worst location)	-0.25" w.g. (worst location)	-0.25" w.g. (worst location)	-0.25" w.g. (worst location)
Drawdown Time	2.5 minutes	10 minutes	10 minutes	10 minutes	10 minutes	20 minutes
Secondary Containment Leakage	2240 cfm	1475 cfm	1475 cfm	1475 cfm	1475 cfm	2240 cfm
Leakage Location[a]	Not specified	Uniform across building elevations	40% Bottom (RR doors) 60% Top (Siding)	40% Bottom (RR doors 60% Top (Siding)	40% Bottom (RR doors) 60% Top (Siding)	BOTTOM/TOP 40%/60%-summer 60%/40%-winter Bottom = RR doors Top = Siding
SW Temperature	40°F-77°F	40°F-75°F	40°F-72°F	32°F - 72°F	32°F - 77°F	32°F - 77°F
Initial Building Temperature	100°F	75°F	75°F	75°F	75°F	50°F winter/75°F summer
Outside Temperature (Most Limiting Case)	Not Specified	12°F (lowest monthly average)	20°F[b]	20°F[b]	20°F[b]	0°F[b]
Wind Conditions (Most Limiting Case)	Not Specified (NCR condition)	10.3 mph (average monthly wind January)	No wind[b]	No wind[b]	No wind[b]	No wind[b]
SGT flow	4457 cfm	5600 cfm	5385-5850 cfm	5385-5850 cfm	5385-5850 cfm	5000 cfm
Flow Limiter Accuracy	Not specified	No impact	±8%	±10%	±7%	±9%(3)
Degraded Voltage	80%	No impact	87%	87%	87%	87%(4)
Flow Element Calibration Error	Not considered	Not considered	-5 to +10%	-5 to +10%	-5 to +10%	-5 to +10%(5)
Assumed Single Failure	SGT	SGT or SW	SGT	SGT	SGT	SGT and SW evaluated SGT is limiting
Room Cooler Efficiency	Not Specified	Not Specified	Not Specified	100%	65%	50%

Table 1

Comparison of Key SGT Parameters
Notes

1.JCO Rev 2, NCR 288-357
2.NE-02-94-19
3.E/I-02-91-1066
4.E/I-02-90-01
5.NE-02-92-06

(a) WNP-2 has credited 40% mixing within the secondary containment for purposes of calculating offsite dose consequences. This differs from the original design basis in that no mixing was credited inside the secondary containment. The method for calculating the effects of mixing assumes 40% of the secondary containment free volume is available for mixing and holdup of radioactive isotopes prior to release via SGT. The basis for selecting the value of 40% is based upon an evaluation using the GOTHIC computer code.

To validate the amount of expected mixing, the GOTHIC model for secondary containment was modified to allow injection of a tracer gas (Xenon) and follow it as it disperses throughout secondary containment. The amount of tracer gas injected was equivalent to the allowable primary to secondary containment leakage of 0.5% by weight per day (L_a). The location selected for primary to secondary containment leakage was varied to account for the various penetration locations. The analysis showed that mixing occurred throughout the secondary containment and was independent of injection point of the tracer gas.

Offsite dose projections were also performed using 40% of the secondary containment free volume for mixing. Qualitative comparison of the concentration versus time of the tracer gas injected in the GOTHIC model with the radioactive isotope concentration versus time from the PADD calculation were performed. The results of this comparison indicates that radioactive isotope concentration versus time for PADD was properly modeled, and that the 40% mixing value is appropriately credited for secondary containment.

(b) Data based on 95% wind and temperature meteorology. See Figure 3.

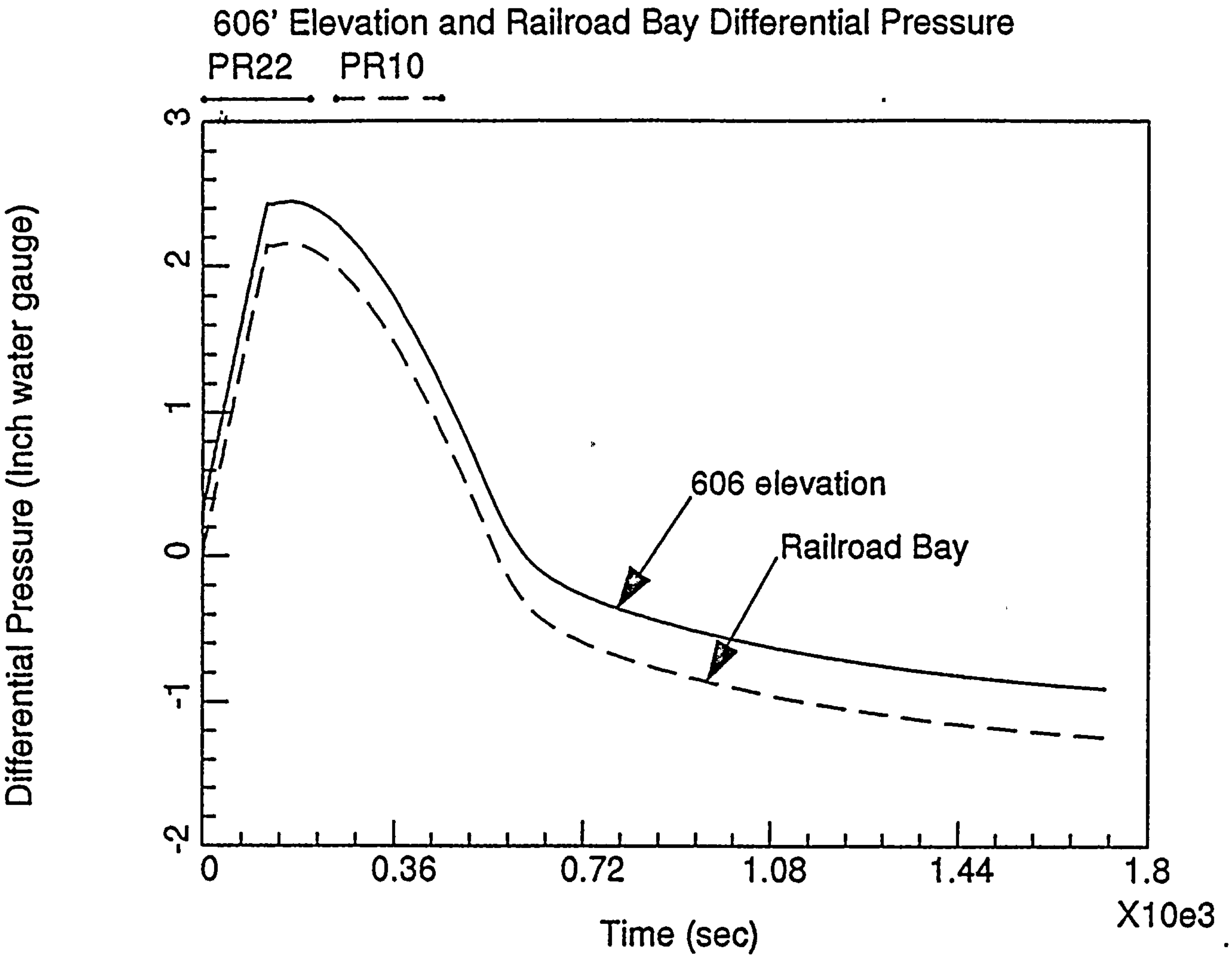


Figure 2 Short Term Differential Pressure Transient Response of the Secondary Containment Following Design Basis Accident and Coincident Loss of Offsite Power.

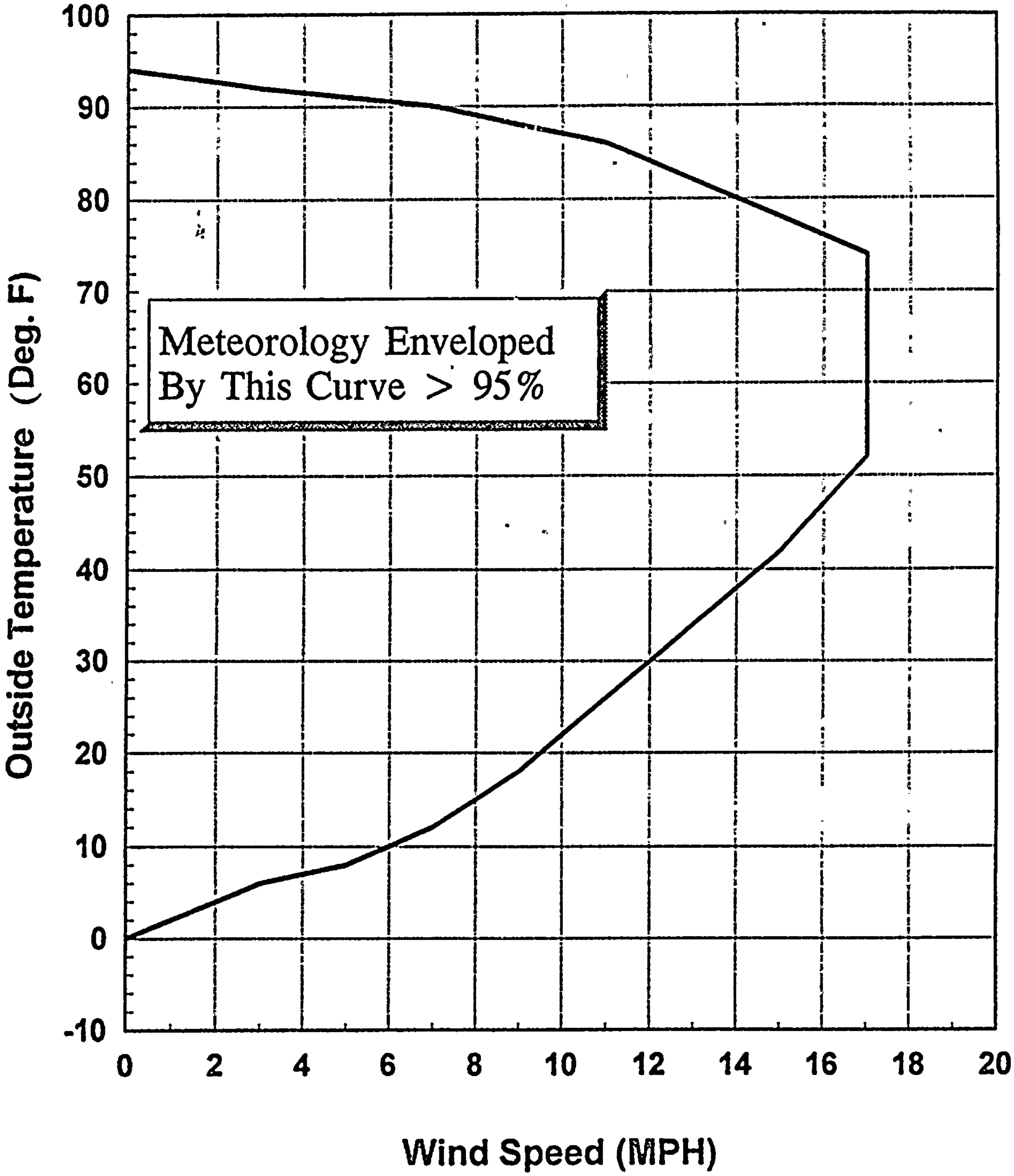
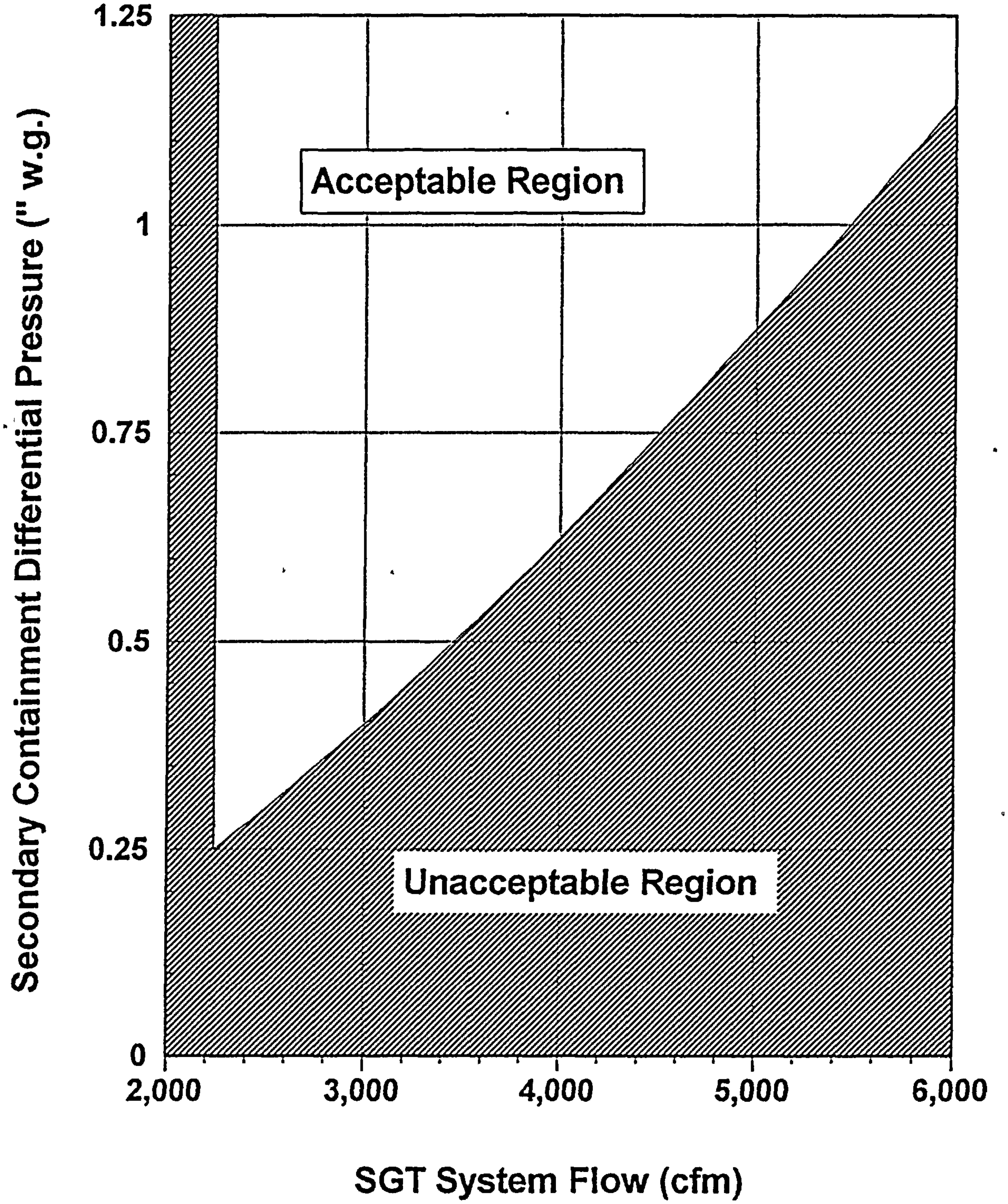


Figure 3: WNP-2 Design Basis Meteorology



Secondary Containment Integrity Performance Limits

Figure 4

TABLE 2
RADIOLOGICAL DOSES

Receptor	Initial SER LOCA Dose	Revised LOCA Dose	10CFR 50/100 and JCO Dose Limits
CONTROL ROOM			
Thyroid	30	15.4	30
Whole Body	5	0.05	5
Beta	30	0.5	30
EAB			
Thyroid	72	114.2	300
Whole Body	9	1.4	25
LPZ			
Thyroid	251	275.6	300
Whole Body	5.9	2.4	25

ATTACHMENT 3A

CTS and Bases Markup