(continued)

(continued)

1.1 Definitions

PHYSICS TESTS (continued)	b. Authorized under the provisions of 10 CFR 50.59; or
	c. Otherwise approved by the Nuclear Regulatory Commission.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3458 MWt.
REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME	The RPS RESPONSE TIME shall be that time interval from the opening of the sensor contact up to and including the opening of the trip actuator contacts.
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rods are fully inserted except for the single control rod of highest reactivity worth, which is assumed to be fully withdrawn.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.

(continued)

1.1 Definitions (continued)

TURBINE BYPASS SYSTEM RESPONSE TIME	The TURBINE BYPASS SYSTEM RESPONSE TIME consists of two components: a. ıhe time from initial movement of the main turbine stop valve or control valve until 80% of the turbine bypass capacity is established; and b. The time from initial movement of the main turbine stop valve or control valve until initial movement of the turbine bypass valve. 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.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3 Perform SR 3.1.3.2 and SR 3.1.3.3 for each withdrawn OPERABLE control rod. AND A.4 Perform SR 3.1.1.1.	24 hours from discovery of Condition A concurrent with THERMAL POWER greater than the low power setpoint (LPSP) of the RWM 72 hours
B. Two or more withdrawn control rods stuck.	B.1 Be in MODE 3.	12 hours
C. One or more control rods inoperable for reasons other than Condition A or B.	C.1 --------NOTE--------- RWM may be bypassed as allowed by LCO 3.3.2.1, if required, to allow insertion of inoperable control rod and continued operation. --------------------- Fully insert inoperable control rod. AND C.2 Disarm the associated CRD.	 3 hours 4 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.14	Perform CHANNEL FUNCTIONAL TEST.	24 months
SR 3.3.1.1.15	Perform CHANNEL CALIBRATION.	24 months
SR 3.3.1.1.16	Calibrate each radiation detector.	24 months
SR 3.3.1.1.17	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months
SR 3.3.1.1.18	Verify the RPS RESPONSE TIME is within limits.	24 months

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 3.3.1.1.11 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 120/125 divisions of full scale
	5(a)	3	H	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.11 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 120/125 divisions of full scale
b. Inop	2	3	G	SR 3.3.1.1.3 SR 3.3.1.1.17	NA
	5(a)	3	H	SR 3.3.1.1.4 SR 3.3.1.1.17	NA
2. Average Power Range Monitors					
a. Startup High Flux Scram	2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.3 SR 3.3.1.1.6 SR 3.3.1.1.8 SR 3.3.1.1.12 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 15.0% RTP
b. Flow Biased High Scram	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 3.3.1.1.12 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 0.66 W + 63.9% RTP(b)
c. Scram Clamp	1	2	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 118.0% RTP
d. Downscale	1	2	F	SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.17	≥ 2.5% RTP
e. Inop	1,2	2	G	SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.17	NA

(continued)

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

(b) 0.66 W + 63.9% - 0.66 ΔW RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

Table 3.3.1.1-1 (page 2 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
3. Reactor Pressure —High	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 1085.0 psig
4. Reactor Vessel Water Level —Low (Level 3)	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≥ 1.0 inches
5. Main Steam Isolation Valve —Closure	1	8	F	SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 10% closed
6. Drywell Pressure —High	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 2.0 psig
7. Scram Discharge Volume Water Level —High	1,2	2	G	SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 50.0 gallons
	5(a)	2	H	SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17	≤ 50.0 gallons
8. Turbine Stop Valve —Closure	≥ 30% RTP	4	E	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 10% closed
9. Turbine Control Valve Fast Closure, Trip Oil Pressure —Low	≥ 30% RTP	2	E	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≥ 500.0 psig
10. Turbine Condenser —Low Vacuum	1	2	F	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≥ 23.0 inches Hg vacuum
11. Main Steam Line —High Radiation	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.10 SR 3.3.1.1.16 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 15 X Full Power Background
12. Reactor Mode Switch — Shutdown Position	1,2	1	G	SR 3.3.1.1.14 SR 3.3.1.1.17	NA
	5(a)	1	H	SR 3.3.1.1.14 SR 3.3.1.1.17	NA

(continued)

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

Table 3.3.1.1-1 (page 3 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
13. Manual Scram	1,2	1	G	SR 3.3.1.1.9 SR 3.3.1.1.17	NA
	$5^{(a)}$	1	H	SR 3.3.1.1.9 SR 3.3.1.1.17	NA
14. RPS Channel Test Switch	1,2	2	G	SR 3.3.1.1.4 SR 3.3.1.1.17	NA
	$5^{(a)}$	2	H	SR 3.3.1.1.4 SR 3.3.1.1.17	NA

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

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 required channels inoperable.	C.1	Restore one required channel to OPERABLE status.	7 days

(continued)

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

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.3.1.1	Perform CHANNEL CHECK for each required PAM instrumentation channel.	31 days
SR 3.3.3.1.2	Perform CHANNEL CALIBRATION of the Drywell and Suppression Chamber H_2 & O_2 Analyzers.	92 days
SR 3.3.3.1.3	Perform CHANNEL CALIBRATION for each required PAM instrumentation channel except for the Drywell and Suppression Chamber H_2 & O_2 Analyzers.	24 months

Table 3.3.5.1-1 (page 2 of 5)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. Low Pressure Coolant Injection (LPCI) System					
a. Reactor Vessel Water Level —Low Low Low (Level 1)	1,2,3, $4^{(a)}$, $5^{(a)}$	4	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ -160 inches
b. Drywell Pressure —High	1,2,3	4	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≤ 2.0 psig
c. Reactor Pressure —Low (Injection Permissive)	1,2,3	4	C	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ 425.0 psig and ≤ 475.0 psig
	$4^{(a)}$, $5^{(a)}$	4	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ 425.0 psig and ≤ 475.0 psig
d. Reactor Pressure —Low Low (Recirculation Discharge Valve Permissive)	$1^{(c)}$, $2^{(c)}$, $3^{(c)}$	4	C	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ 211.0 psig
e. Reactor Vessel Shroud Level —Level 0	1,2,3	2	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ -226.0 inches
f. Low Pressure Coolant Injection Pump Start —Time Delay Relay (offsite power available)	1,2,3, $4^{(a)}$, $5^{(a)}$	8 (2 per pump)	C	SR 3.3.5.1.4 SR 3.3.5.1.5	
Pumps A,B					≥ 1.9 seconds and ≤ 2.1 seconds
Pumps C,D					≥ 7.5 seconds and ≤ 8.5 seconds
g. Low Pressure Coolant Injection Pump Discharge Flow —Low (Bypass)	1,2,3 $4^{(a)}$, $5^{(a)}$	4 (1 per pump)	E	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ 299.0 psid and ≤ 331.0 psid

(continued)

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

(c) With associated recirculation pump discharge valve open.

3.3 INSTRUMENTATION

3.3.8.1 Loss of Power (LOP) Instrumentation

LCO 3.3.8.1 The Unit 2 LOP instrumentation for each Function in Table 3.3.8.1-1 shall be OPERABLE.

AND

The Unit 3 LOP instrumentation for Functions 1, 2, 3, and 5 in Unit 3 Table 3.3.8.1-1 shall be OPERABLE.

APPLICABILITY: When the associated diesel generator and offsite circuit are required to be OPERABLE by LCO 3.8.1, "AC Sources—Operating," or LCO 3.8.2, "AC Sources—Shutdown."

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One 4 kV emergency bus with one or two required Function 3 channels inoperable. OR One 4 kV emergency bus with one or two required Function 5 channels inoperable.	A.1 --------NOTE--------- Enter applicable Conditions and Required Actions of LCO 3.8.1 for offsite circuits made inoperable by LOP instrumentation. -------------------- Place channel in trip.	 14 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. Two 4 kV emergency buses with one required Function 3 channel inoperable. OR Two 4 kV emergency buses with one required Function 5 channel inoperable. OR One 4 kV emergency bus with one required Function 3 channel inoperable and a different 4 kV emergency bus with one required Function 5 channel inoperable.	B.1	---------NOTE--------- Enter applicable Conditions and Required Actions of LCO 3.8.1 for offsite circuits made inoperable by LOP instrumentation. --------------------- Place the channel in trip.	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One or more 4 kV emergency buses with one or more required Function 1, 2, or 4 channels inoperable. <u>OR</u> One 4 kV emergency bus with one required Function 3 channel and one required Function 5 channel inoperable. <u>OR</u> Any combination of three or more required Function 3 and Function 5 channels inoperable.	C.1	--------NOTE--------- Enter applicable Conditions and Required Actions of LCO 3.8.1 for offsite circuits made inoperable by LOP instrumentation. --------------------- Place the channel in trip.	1 hour
D. Required Action and associated Completion Time not met.	D.1	Declare associated diesel generator (DG) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

-NOTES-

1. Refer to Table 3.3.8.1-1 to determine which SRs apply for each Unit 2 LOP Function. SR 3.3.8.1.5 is applicable only to the Unit 3 LOP instrumentation.

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: (a) for Function 1, the associated Function maintains initiation capability for three DGs; and (b) for Functions 2, 3, 4, and 5, the associated Function maintains undervoltage transfer capability for three 4 kV emergency buses.

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 FUNCTIONAL TEST.	24 months
SR 3.3.8.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months
SR 3.3.8.1.5	For required Unit 3 LOP instrumentation Functions, the SRs of Unit 3 Specification 3.3.8.1 are applicable.	In accordance with applicable SRs

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

FUNCTION	REQUIRED CHANNELS PER BUS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. 4 kV Emergency Bus Undervoltage (Loss of Voltage)			
a. Bus Undervoltage	1	SR 3.3.8.1.3 SR 3.3.8.1.4	NA
2. 4 kV Emergency Bus Undervoltage (Degraded Voltage Low Setting)			
a. Bus Undervoltage	2 (1 per source)	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 2288 V and ≤ 2704 V
b. Time Delay	2 (1 per source)	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 1.6 seconds and ≤ 2.0 seconds
3. 4 kV Emergency Bus Undervoltage (Degraded Voltage High Setting)			
a. Bus Undervoltage	2 (1 per source)	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 3411 V and ≤ 3827 V
b. Time Delay	2 (1 per source)	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 27.0 seconds and ≤ 33.0 seconds
4. 4 kV Emergency Bus Undervoltage (Degraded Voltage LOCA)			
a. Bus Undervoltage	2 (1 per source)	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 3691 V and ≤ 3713 V, with internal time delay set ≥ 0.9 seconds and ≤ 1.1 seconds
b. Time Delay	2 (1 per source)	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 8.4 seconds and ≤ 9.6 seconds
5. 4 kV Emergency Bus Undervoltage (Degraded Voltage non-LOCA)			
a. Bus Undervoltage	2 (1 per source)	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 4065 V and ≤ 4089 V, with internal time delay set ≥ 0.9 seconds and ≤ 1.1 seconds
b. Time Delay	2 (1 per source)	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 57.0 seconds and ≤ 63.0 seconds

3.3 INSTRUMENTATION

3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

LCO 3.3.8.2 Two RPS electric power monitoring assemblies shall be OPERABLE for each inservice RPS motor generator set or alternate power supply.

APPLICABILITY: MODES 1 and 2,
MODES 3, 4, and 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or both inservice power supplies with one electric power monitoring assembly inoperable.	A.1	Remove associated inservice power supply(s) from service.	72 hours
B. One or both inservice power supplies with both electric power monitoring assemblies inoperable.	B.1	Remove associated inservice power supply(s) from service.	1 hour
C. Required Action and associated Completion Time of Condition A or B not met in MODE 1 or 2.	C.1	Be in MODE 3.	12 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 3, 4, or 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.	D.1	Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.8.2.1	------------------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 for each RPS motor generator set electric power monitoring assembly. The Allowable Values shall be: a. Overvoltage ≤ 133 V, with time delay set to ≤ 1.5 seconds. b. Undervoltage ≥ 111 V, with time delay set to ≤ 1.5 seconds. c. Underfrequency ≥ 56.8 Hz, with time delay set to ≤ 7.0 seconds.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.8.2.3	Perform CHANNEL CALIBRATION for each RPS alternate power supply electric power monitoring assembly. The Allowable Values shall be: a. Overvoltage ≤ 133 V, with time delay set to ≤ 1.5 seconds. b. Undervoltage ≥ 111 V, with time delay set to ≤ 4.0 seconds. c. Underfrequency ≥ 56.8 Hz, with time delay set to ≤ 1.5 seconds.	24 months
SR 3.3.8.2.4	Perform a system functional test.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.1 Recirculation Loops Operating

LCO 3.4.1 Two recirculation loops with matched flows shall be in operation with core flow as a function of THERMAL POWER in the "Unrestricted" Region of Figure 3.4.1-1.

<u>OR</u>

One recirculation loop shall be in operation with core flow as a function of THERMAL POWER in the "Unrestricted" Region of Figure 3.4.1-1 and with the following limits applied when the associated LCO is applicable:

a. LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," single loop operation limits specific in the COLR;

b. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," single loop operation limits specified in the COLR; and

c. LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," Function 2.b (Average Power Range Monitors Flow Biased High Scram), Allowable Value of Table 3.3.1.1-1 is reset for single loop operation.

-----------------------------NOTE-----------------------------
Required limit modifications for single recirculation loop operation may be delayed for up to 12 hours after transition from two recirculation loop operation to single recirculation loop operation.

APPLICABILITY: MODES 1 and 2.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.9 RCS Pressure and Temperature (P/T) Limits

LCO 3.4.9 RCS pressure, RCS temperature, RCS heatup and cooldown rates, and the recirculation pump starting temperature requirements shall be maintained within limits.

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. <u>AND</u> C.2 Determine RCS is acceptable for operation.	Immediately Prior to entering MODE 2 or 3.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.9.1	-------------------NOTE------------------- Only required to be performed during RCS heatup and cooldown operations and RCS inservice leak and hydrostatic testing. --- Verify: a. RCS pressure and RCS temperature are within the applicable limits specified in Figures 3.4.9-1 and 3.4.9-2; and b. RCS heatup and cooldown rates are ≤ 100°F in any 1 hour period.	30 minutes

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.9.2	Verify RCS pressure and RCS temperature are within the criticality limits specified in Figure 3.4.9-3.	Once within 15 minutes prior to control rod withdrawal for the purpose of achieving criticality
SR 3.4.9.3	-------------------NOTE------------------ Only required to be met in MODES 1, 2, 3, and 4 during recirculation pump start. --- 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 3.4.9.4	-------------------NOTE------------------ Only required to be met in MODES 1, 2, 3, and 4 during recirculation pump start. --- 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 3.4.9.5	------------------NOTE------------------ Only required to be performed when tensioning the reactor vessel head bolting studs. -- Verify reactor vessel flange and head flange temperatures are > 70°F.	30 minutes
SR 3.4.9.6	------------------NOTE------------------ Not required to be performed until 30 minutes after RCS temperature ≤ 80°F in MODE 4. -- Verify reactor vessel flange and head flange temperatures are > 70°F.	30 minutes
SR 3.4.9.7	------------------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 > 70°F.	12 hours

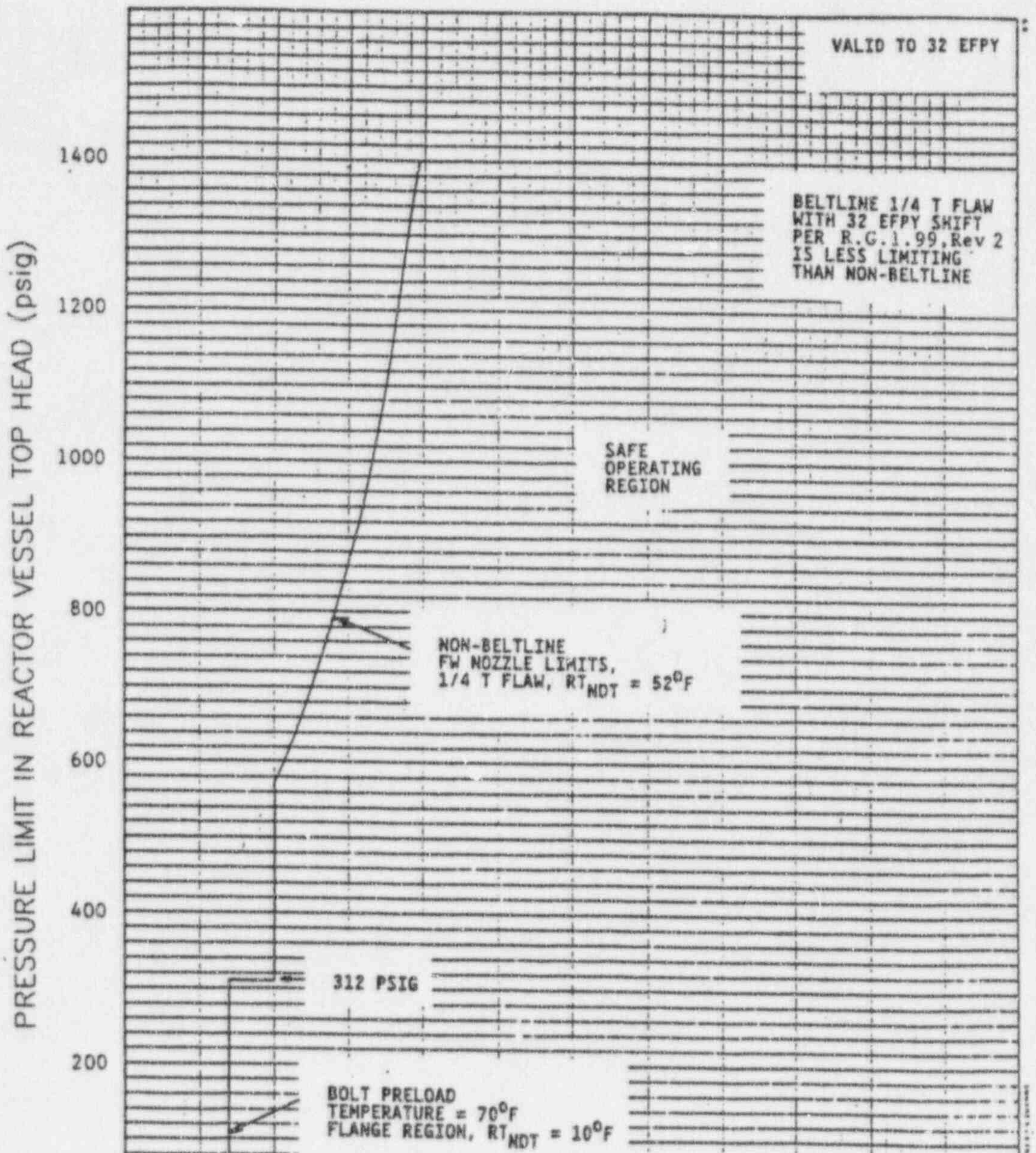

Figure 3.4.9-1 (page 1 of 1)

Temperature/Pressure Limits for
Inservice Hydrostatic and Inservice Leakage Tests

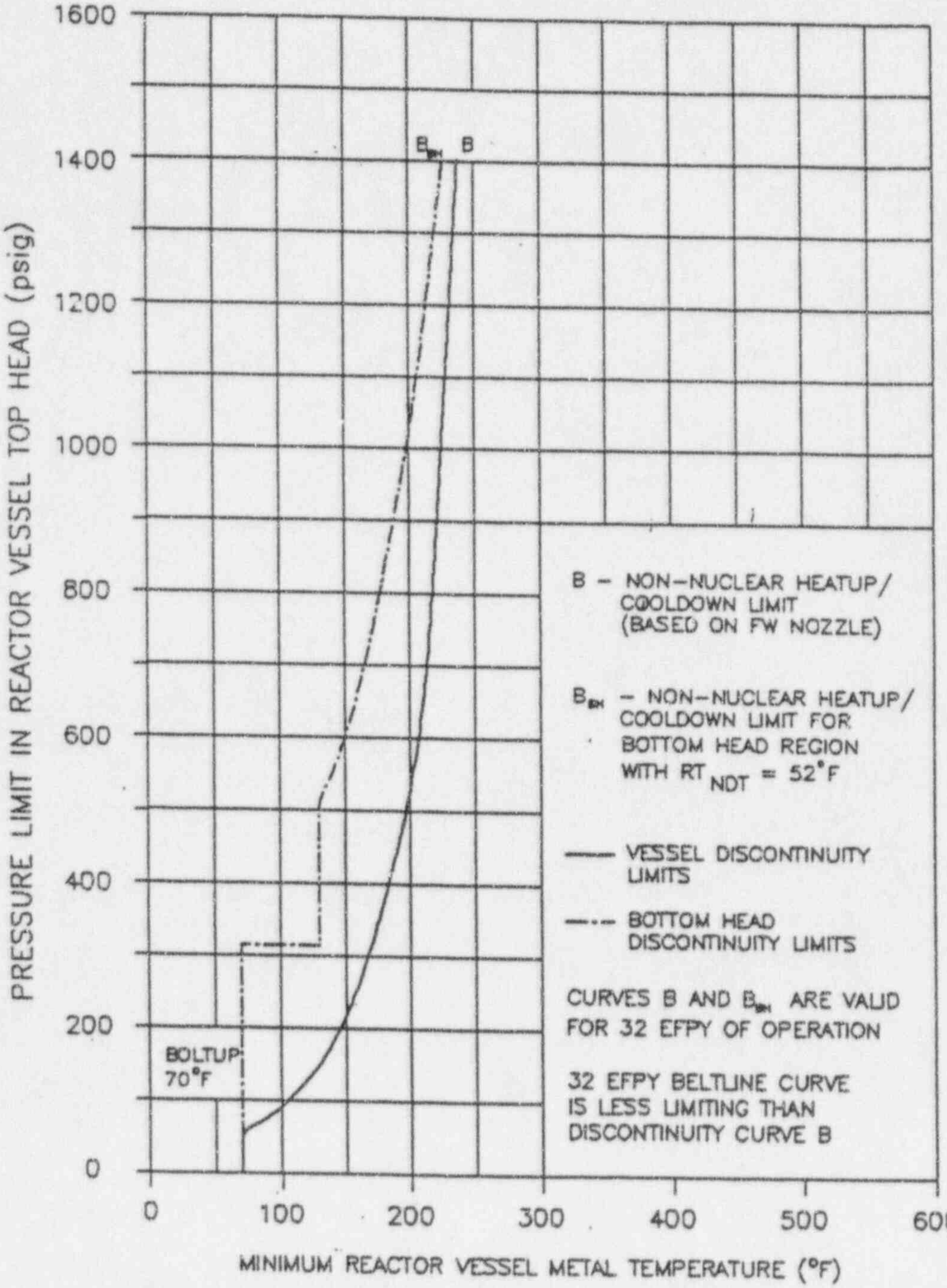

Figure 3.4.9-2 (page 1 of 1)

Temperature/Pressure Limits for
Non-Nuclear Heatup and Cooldown Following a Shutdown

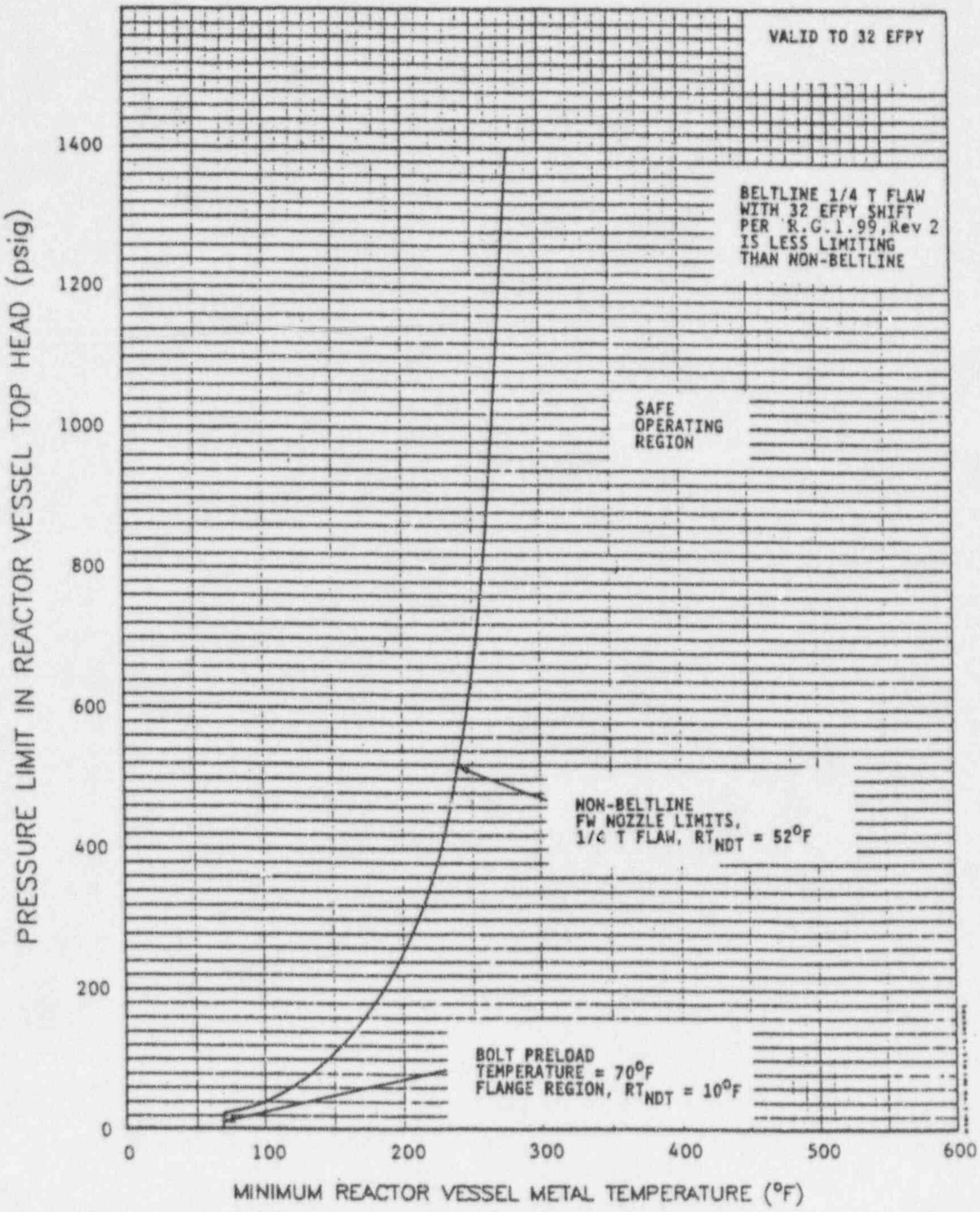

Figure 3.4.9-3 (page 1 of 1)

Temperature/Pressure Limits for Criticality

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.10 Reactor Steam Dome Pressure

LCO 3.4.10 The reactor steam dome pressure shall be ≤ 1053 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 3.4.10.1	Verify reactor steam dome pressure is ≤ 1053 psig.	12 hours

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

3.5.2 ECCS—Shutdown

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

APPLICABILITY: MODE 4,
MODE 5, except with the spent fuel storage pool gates removed, water level ≥ 458 inches above reactor pressure vessel instrument zero, and no operations with a potential for draining the reactor vessel (OPDRVs) in progress.

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 OPDRVs.	Immediately
C. Two required ECCS injection/spray subsystems inoperable.	C.1 Initiate action to suspend OPDRVs. AND C.2 Restore one ECCS injection/spray subsystem to OPERABLE status.	Immediately 4 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.2.2	-------------------NOTE------------------- Only required to be performed upon entry into primary containment when the primary containment is de-inerted. --	
	Verify only one door in the primary containment air lock can be opened at a time.	184 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One offsite circuit inoperable. AND One DG inoperable.	------------NOTE------------ Enter applicable Conditions and Required Actions of LCO 3.8.7, "Distribution Systems—Operating," when Condition D is entered with no AC power source to any 4 kV emergency bus. ----------------------------	
	D.1 Restore offsite circuit to OPERABLE status.	12 hours
	OR	
	D.2 Restore DG to OPERABLE status.	12 hours
E. Two or more DGs inoperable.	E.1 Restore all but one DG to OPERABLE status.	2 hours
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. One or more offsite circuits and two or more DGs inoperable. OR Two or more offsite circuits and one DG inoperable.	G.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.20	-------------------NOTES------------------- 1. All DG starts may be preceded by an engine prelube period. 2. A single test at the specified Frequency will satisfy this Surveillance for both units. --- Verify, when started simultaneously from standby condition, each DG achieves, in ≤ 10 seconds, voltage ≥ 4160 V and frequency ≥ 58.8 Hz.	10 years
SR 3.8.1.21	-------------------NOTE------------------- When Unit 3 is in MODE 4 or 5, or moving irradiated fuel assemblies in the secondary containment, the Note to Unit 3 SR 3.8.2.1 is applicable. --- For required Unit 3 AC sources, the SRs of Unit 3 Specification 3.8.1, except SR 3.8.1.8 (when only one Unit 3 offsite circuit is required), SR 3.8.1.12, SR 3.8.1.13, SR 3.8.1.17, SR 3.8.1.18 (ECCS load block requirement only), and SR 3.8.1.19, are applicable.	In accordance with applicable SRs

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more required offsite circuits inoperable.	-----NOTE----- Enter applicable Condition and Required Actions of LCO 3.8.8, with one or more required 4 kV emergency buses 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)

SURVEILLANCE REQUIREMENTS

-----------------------------------NOTE-----------------------------------
SR 3.8.4.1 through SR 3.8.4.8 are pplicable only to the Unit 2 DC electrical power subsystems. SR 3.8.4.9 is applicable only to the Unit 3 DC electrical power subsystems.

	SURVEILLANCE	FREQUENCY
SR 3.8.4.1	Verify battery terminal voltage is ≥ 123.5 V on float charge.	-----NOTE------ The 7 day Frequency is not applicable if the battery is on equalize charge or has been on equalize charge at any time during the previous 1 day. --------------- 7 days AND 14 days
SR 3.8.4.2	Verify no visible corrosion at battery terminals and connectors. OR Verify battery connection resistance is ≤ 40 E-6 ohms.	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 could potentially degrade battery performance.	12 months

(continued)

5.5 Programs and Manuals (continued)

5.5.4 Radioactive Effluent Controls Program

This program conforms to 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents as low as reasonably achievable. The program 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:

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 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. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.1302 and with the methodology and parameters in the ODCM;

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 liquid radioactive effluents and determination of cumulative dose contributions from gaseous 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 effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when projected doses averaged over one month would exceed 0.12 mrem to the total body or 0.4 mrem to any organ (combined total from the two reactors at the site);

g. Limitations to ensure gaseous effluents shall be processed, prior to release, through the appropriate gaseous effluent treatment systems as described in the ODCM;

(continued)

5.5 Programs and Manuals

5.5.4 Radioactive Effluent Controls Program (continued)

h. Limitations on the dose rate resulting from radioactive material released in gaseous effluents to areas beyond the site boundary shall be limited to the following:

1. For noble gases: less than or equal to a dose rate of 500 mrems/yr to the total body and less than or equal to a dose rate of 3000 mrems/yr to the skin, and

2. For iodine-131, iodine-133, tritium, and for all radionuclides in particulate form with half lives > 8 days: less than or equal to a dose rate of 1500 mrems/yr to any organ;

i. Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I;

j. Limitations on the annual and quarterly doses to a member of the public from iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half lives > 8 days in gaseous effluents released from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I; and

k. Limitations on the annual dose or dose commitment to any member of the public due to releases of radioactivity and to radiation from uranium fuel cycle sources, conforming to 40 CFR 190.

5.5.5 Component Cyclic or Transient Limit

This program provides controls to track the UFSAR, Table 4.2.4, cyclic and transient occurrences to ensure that components are maintained within the design limits.

(continued)

5.5 Programs and Manuals (continued)

5.5.6 Inservice Testing Program

This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components including applicable supports. The program shall include the following:

a. Testing frequencies specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda are as follows:

ASME Boiler and Pressure Vessel Code and applicable Addenda terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 732 days

b. The provisions of SR 3.0.2 are applicable to the Frequencies for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any TS.

5.5.7 Ventilation Filter Testing Program (VFTP)

The VFTP shall establish the required testing of Engineered Safety Feature (ESF) filter ventilation systems.

Tests described in Specifications 5.5.7.a, 5.5.7.b, and 5.5.7.c shall be performed:

(continued)

5.5 Programs and Manuals

5.5.7 Ventilation Filter Testing Program (VFTP) (continued)

1) Once per 12 months for standby service or after 720 hours of system operation; and,

2) After each complete or partial replacement of the HEPA filter train or charcoal adsorber filter; 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 Specifications 5.5.7.d and 5.5.7.e shall be performed once per 24 months.

The test described in Specification 5.5.7.f shall be performed once per 12 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 HEPA filters shows a penetration and system bypass < 0.05% when tested in accordance with Regulatory Guide 1.52, Revision 2, Section 5c, and ASME N510-1989, Sections 6 (Standby Gas Treatment (SGT) System only) and 10, at the system flowrate specified below.

ESF Ventilation System	Flowrate (cfm)
SGT System	7200 to 8800
Main Control Room Emergency Ventilation (MCREV) System	2700 to 3300

(continued)

5.5 Programs and Manuals

5.5.7 Ventilation Filter Testing Program (VFTP) (continued)

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, Section 5d, and ASME N510-1989, Sections 6 (SGT System only) and 11, at the system flowrate specified below.

ESF Ventilation System	Flowrate (cfm)
SGT System	7200 to 8800
MCREV System	2700 to 3300

c. Demonstrate for each of the ESF systems that a laboratory test of a sample of the charcoal adsorber, when obtained as described in Regulatory Guide 1.52, Revision 2, Section 6b, shows the methyl iodide penetration less than the value specified below when tested at the conditions specified below.

	ESF Ventilation System	
	SGT System	MCREV System
Methyl iodide removal rate: (%)	≥ 95	≥ 90
Methyl iodide concentration: (mg/m^3)	0.5 to 1.5	0.05 to 0.15
Flow rate: (% design flow)	80 to 120	80 to 120
Temperature: (degrees F)	≥ 190	≥ 125
Relative Humidity: (%)	≥ 70	≥ 95

(continued)

5.5 Programs and Manuals

5.5.7 Ventilation Filter Testing Program (VFTP) (continued)

d. Demonstrate for each of the ESF systems that the pressure drop across the combined HEPA filters, the prefilters (if installed), 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	< 3.9	7200 to 8800
MCREV System	< 8	2700 to 3300

e. Demonstrate that the heaters for the SGT System dissipate ≥ 40 kw.

5.5.8 Explosive Gas Monitoring Program

This program provides controls for potentially explosive gas mixtures contained downstream of the off-gas recombiners.

The program shall include:

a. The limit for the concentration of hydrogen downstream of the off-gas recombiners and a surveillance program to ensure the limit is maintained. This limit shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion);

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas Monitoring Program surveillance frequencies.

5.5.9 Diesel Fuel Oil Testing Program

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

(continued)

5.5 Programs and Manuals

5.5.9 Diesel Fuel Oil Testing Program (continued)

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

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

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

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

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 is ≤ 10 mg/l when tested every 31 days in accordance with ASTM D2276, Method A, except that the filters specified in the ASTM method may have a nominal pore size of up to three (3) microns.

5.5.10 Technical Specifications (TS) Bases Control Program

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

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

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

A change in the TS incorporated in the license; or

A change to the UFSAR 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 UFSAR.

(continued)

5.5 Programs and Manuals

5.5.10 Technical Specifications (TS) Bases Control Program (continued)

d. Proposed changes that meet the criteria of 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).

5.5.11 Safety Function Determination Program (SFDP)

This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate limitations and remedial or compensatory actions may be identified to be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6.

a. The SFDP shall contain the following:

   1. Provisions for cross division checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

   2. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

   3. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

   4. Other appropriate limitations and remedial or compensatory actions.

b. A loss of safety function exists when, assuming no concurrent single failure, a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

(continued)

5.5 Programs and Manuals

5.5.11 Safety Function Determination Program (SFDP) (continued)

1. A required system redundant to system(s) supported by the inoperable support system is also inoperable; or

2. A required system redundant to system(s) in turn supported by the inoperable supported system is also inoperable; or

3. A required system redundant to support system(s) for the supported systems (b.1) and (b.2) above is also inoperable.

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

5.0 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

-----NOTE-----
A single submittal may be made for a multiple unit station. The submittal should combine sections common to all units at the station.

A tabulation on an annual basis of the number of station, utility, and other personnel (including contractors) receiving an annual deep dose equivalent > 100 mrem and the associated collective deep dose equivalent (reported in person-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 pocket dosimeter, thermoluminescence 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 deep dose equivalent received from external sources should be assigned to specific major work functions. The report shall be submitted by March 31 of each year.

5.6.2 Annual Radiological Environmental Operating Report

-----NOTE-----
A single submittal may be made for a multiple unit station. The submittal should combine sections common to all units at the station.

The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted by May 31 of each year. The report shall include summaries, interpretations, and analyses of trends of the results of the radiological environmental monitoring activities 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.

(continued)

5.6 Reporting Requirements

5.6.2 Annual Radiological Environmental Operating Report (continued)

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

5.6.3 Radioactive Effluent Release Report

-------------------------------NOTE-------------------------------
A single submittal may be made for a multiple unit station. The submittal should combine sections common to all units at the station.

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

5.6.4 Monthly Operating Reports

Routine reports of operating statistics and shutdown experience shall be submitted on a monthly basis no later than the 15th of each month following the calendar month covered by the report.

(continued)

5.6 Reporting Requirements (continued)

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 Average Planar Linear Heat Generation Rate for Specification 3.2.1;

   2. The Minimum Critical Power Ratio for Specifications 3.2.2 and 3.3.2.1;

   3. The Linear Heat Generation Rate for Specification 3.2.3; and

   4. The Control Rod Block Instrumentation for Specification 3.3.2.1.

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

   1. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel" (latest approved version as specified in the COLR);

   2. NEDC-32162P, "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Peach Bottom Atomic Power Station Units 2 and 3," Revision 1, February, 1993;

   3. PECo-FMS-0001-A, "Steady-State Thermal Hydraulic Analysis of Peach Bottom Units 2 and 3 using the FIBWR Computer Code";

   4. PECo-FMS-0002-A, "Method for Calculating Transient Critical Power Ratios for Boiling Water Reactors (RETRAN-TCPPECo)";

   5. PECo-FMS-0003-A, "Steady-State Fuel Performance Methods Report";

   6. PECo-FMS-0004-A, "Methods for Performing BWR Systems Transient Analysis";

(continued)

5.6 Reporting Requirements

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

7. PECo-FMS-0005-A, "Methods for Performing BWR Steady-State Reactor Physics Analysis"; and

8. PECo-FMS-0006-A, "Methods for Performing BWR Reload Safety Evaluations."

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 Areas

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 accessible 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. 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 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:

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

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, or

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

(continued)

5.7 High Radiation Areas

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 direct-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.

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 accessible 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 radiation protection personnel.

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

(continued)

5.7 High Radiation Areas

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> (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: B

1. An alarming dosimeter with an appropriate alarm setpoint, or

2. A radiation monitoring device that continuously transmits dose rate or cumulative dose information 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, or

3. A direct-reading dosimeter and,

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

(continued)

5.7 High Radiation Areas

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> (continued)

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

4. A radiation monitoring and indicating device in those cases where the options of Specifications 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.

B

(continued)

(continued)

1.1 Definitions

PHYSICS TESTS (continued)	b. Authorized under the provisions of 10 CFR 50.59; or
	c. Otherwise approved by the Nuclear Regulatory Commission.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3458 MWt.
REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME	The RPS RESPONSE TIME shall be that time interval from the opening of the sensor contact up to and including the opening of the trip actuator contacts.
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.

(continued)

1.1 Definitions (continued)

TURBINE BYPASS SYSTEM RESPONSE TIME	The TURBINE BYPASS SYSTEM RESPONSE TIME consists of two components: a. The time from initial movement of the main turbine stop valve or control valve until 80% of the turbine bypass capacity is established; and b. The time from initial movement of the main turbine stop valve or control valve until initial movement of the turbine bypass valve. 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.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.3	Perform SR 3.1.3.2 and SR 3.1.3.3 for each withdrawn OPERABLE control rod.	24 hours from discovery of Condition A concurrent with THERMAL POWER greater than the low power setpoint (LPSP) of the RWM
	AND		
	A.4	Perform SR 3.1.1.1.	72 hours
B. Two or more withdrawn control rods stuck.	B.1	Be in MODE 3.	12 hours
C. One or more control rods inoperable for reasons other than Condition A or B.	C.1	---------NOTE--------- RWM may be bypassed as allowed by LCO 3.3.2.1, if required, to allow insertion of inoperable control rod and continued operation. ---------------------	
		Fully insert inoperable control rod.	3 hours
	AND		
	C.2	Disarm the associated CRD.	4 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
SR 3.3.1.1.14 Perform CHANNEL FUNCTIONAL TEST.	24 months
SR 3.3.1.1.15 Perform CHANNEL CALIBRATION.	24 months
SR 3.3.1.1.16 Calibrate each radiation detector.	24 months
SR 3.3.1.1.17 Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months
SR 3.3.1.1.18 Verify the RPS RESPONSE TIME is within limits.	24 months

B

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 3.3.1.1.11 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 120/125 divisions of full scale
	5(a)	3	H	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.11 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 120/125 divisions of full scale
b. Inop	2	3	G	SR 3.3.1.1.3 SR 3.3.1.1.17	NA
	5(a)	3	H	SR 3.3.1.1.4 SR 3.3.1.1.17	NA
2. Average Power Range Monitors					
a. Startup High Flux Scram	2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.3 SR 3.3.1.1.6 SR 3.3.1.1.8 SR 3.3.1.1.12 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 15.0% RTP
b. Flow Biased High Scram	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 3.3.1.1.12 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 0.66 W + 63.9% RTP(b)
c. Scram Clamp	1	2	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 118.0% RTP
d. Downscale	1	2	F	SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.17	≥ 2.5% RTP
e. Inop	1,2	2	G	SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.17	NA

(continued)

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

(b) 0.66 W + 63.9% - 0.66 ΔW RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

Table 3.3.1.1-1 (page 2 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
3. Reactor Pressure —High	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 1085.0 psig
4. Reactor Vessel Water Level —Low (Level 3)	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≥ 1.0 inches
5. Main Steam Isolation Valve —Closure	1	8	F	SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 10% closed
6. Drywell Pressure —High	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 2.0 psig
7. Scram Discharge Volume Water Level —High	1,2	2	G	SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 50.0 gallons
	5(a)	2	H	SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17	≤ 50.0 gallons
8. Turbine Stop Valve —Closure	≥ 30% RTP	4	E	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 10% closed
9. Turbine Control Valve Fast Closure, Trip Oil Pressure —Low	≥ 30% RTP	2	E	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≥ 500.0 psig
10. Turbine Condenser —Low Vacuum	1	2	F	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≥ 23.0 inches Hg vacuum
11. Main Steam Line —High Radiation	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.10 SR 3.3.1.1.16 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 15 X Full Power Background
12. Reactor Mode Switch — Shutdown Position	1,2	1	G	SR 3.3.1.1.14 SR 3.3.1.1.17	NA
	5(a)	1	H	SR 3.3.1.1.14 SR 3.3.1.1.17	NA

(continued)

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

Table 3.3.1.1-1 (page 3 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
13. Manual Scram	1,2	1	G	SR 3.3.1.1.9 SR 3.3.1.1.17	NA
	$5^{(a)}$	1	H	SR 3.3.1.1.9 SR 3.3.1.1.17	NA
14. RPS Channel Test Switch	1,2	2	G	SR 3.3.1.1.4 SR 3.3.1.1.17	NA
	$5^{(a)}$	2	H	SR 3.3.1.1.4 SR 3.3.1.1.17	NA

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

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 required channels inoperable.	C.1	Restore one required channel to OPERABLE status.	7 days

(continued)

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

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.3.1.1	Perform CHANNEL CHECK for each required PAM instrumentation channel.	31 days
SR 3.3.3.1.2	Perform CHANNEL CALIBRATION of the Drywell and Suppression Chamber H_2 & O_2 Analyzers.	92 days
SR 3.3.3.1.3	Perform CHANNEL CALIBRATION for each required PAM instrumentation channel except for the Drywell and Suppression Chamber H_2 & O_2 Analyzers.	24 months

Table 3.3.5.1-1 (page 2 of 5)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. Low Pressure Coolant Injection (LPCI) System					
a. Reactor Vessel Water Level —Low Low Low (Level 1)	1,2,3, $4^{(a)}$, $5^{(a)}$	4	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ -160 inches
b. Drywell Pressure —High	1,2,3	4	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≤ 2.0 psig
c. Reactor Pressure —Low (Injection Permissive)	1,2,3	4	C	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ 425.0 psig and ≤ 475.0 psig
	$4^{(a)}$, $5^{(a)}$	4	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ 425.0 psig and ≤ 475.0 psig
d. Reactor Pressure —Low Low (Recirculation Discharge Valve Permissive)	$1^{(c)}$, $2^{(c)}$, $3^{(c)}$	4	C	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ 211.0 psig
e. Reactor Vessel Shroud Level —Level 0	1,2,3	2	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ -226.0 inches
f. Low Pressure Coolant Injection Pump Start —Time Delay Relay (offsite power available)	1,2,3, $4^{(a)}$, $5^{(a)}$	8 (2 per pump)	C	SR 3.3.5.1.4 SR 3.3.5.1.5	
Pumps A,B					≥ 1.9 seconds and ≤ 2.1 seconds
Pumps C,D					≥ 7.5 seconds and ≤ 8.5 seconds
g. Low Pressure Coolant Injection Pump Discharge Flow —Low (Bypass)	1,2,3 $4^{(a)}$, $5^{(a)}$	4 (1 per pump)	E	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ 299.0 psid and ≤ 331.0 psid

(continued)

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

(c) With associated recirculation pump discharge valve open.

3.3 INSTRUMENTATION

3.3.8.1 Loss of Power (LOP) Instrumentation

LCO 3.3.8.1 The Unit 3 LOP instrumentation for each Function in Table 3.3.8.1-1 shall be OPERABLE.

AND

The Unit 2 LOP instrumentation for Functions 1, 2, 3, and 5 in Unit 2 Table 3.3.8.1-1 shall be OPERABLE.

APPLICABILITY: When the associated diesel generator and offsite circuit are required to be OPERABLE by LCO 3.8.1, "AC Sources—Operating," or LCO 3.8.2, "AC Sources—Shutdown."

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One 4 kV emergency bus with one or two required Function 3 channels inoperable. OR One 4 kV emergency bus with one or two required Function 5 channels inoperable.	A.1 --------NOTE-------- Enter applicable Conditions and Required Actions of LCO 3.8.1 for offsite circuits made inoperable by LOP instrumentation. -------------------- Place channel in trip.	 14 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. Two 4 kV emergency buses with one required Function 3 channel inoperable. <u>OR</u> Two 4 kV emergency buses with one required Function 5 channel inoperable. <u>OR</u> One 4 kV emergency bus with one required Function 3 channel inoperable and a different 4 kV emergency bus with one required Function 5 channel inoperable.	B.1	--------NOTE--------- Enter applicable Conditions and Required Actions of LCO 3.8.1 for offsite circuits made inoperable by LOP instrumentation. --------------------- Place the channel in trip.	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more 4 kV emergency buses with one or more required Function 1, 2, or 4 channels inoperable. OR One 4 kV emergency bus with one required Function 3 channel and one required Function 5 channel inoperable. OR Any combination of three or more required Function 3 and Function 5 channels inoperable.	C.1 --------NOTE-------- Enter applicable Conditions and Required Actions of LCO 3.8.1 for offsite circuits made inoperable by LOP instrumentation. --------------------- Place the channel in trip.	1 hour
D. Required Action and associated Completion Time not met.	D.1 Declare associated diesel generator (DG) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

-NOTES-

1. Refer to Table 3.3.8.1-1 to determine which SRs apply for each Unit 3 LOP Function. SR 3.3.8.1.5 is applicable only to the Unit 2 LOP instrumentation.

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: (a) for Function 1, the associated Function maintains initiation capability for three DGs; and (b) for Functions 2, 3, 4, and 5, the associated Function maintains undervoltage transfer capability for three 4 kV emergency buses.

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 FUNCTIONAL TEST.	24 months
SR 3.3.8.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months
SR 3.3.8.1.5	For required Unit 2 LOP instrumentation Functions, the SRs of Unit 2 Specification 3.3.8.1 are applicable.	In accordance with applicable SRs

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

FUNCTION	REQUIRED CHANNELS PER BUS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. 4 kV Emergency Bus Undervoltage (Loss of Voltage)			
a. Bus Undervoltage	1	SR 3.3.8.1.3 SR 3.3.8.1.4	NA
2. 4 kV Emergency Bus Undervoltage (Degraded Voltage Low Setting)			
a. Bus Undervoltage	2 (1 per source)	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 2288 V and ≤ 2704 V
b. Time Delay	2 (1 per source)	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 1.6 seconds and ≤ 2.0 seconds
3. 4 kV Emergency Bus Undervoltage (Degraded Voltage High Setting)			
a. Bus Undervoltage	2 (1 per source)	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 3411 V and ≤ 3827 V
b. Time Delay	2 (1 per source)	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 27.0 seconds and ≤ 33.0 seconds
4. 4 kV Emergency Bus Undervoltage (Degraded Voltage LOCA)			
a. Bus Undervoltage	2 (1 per source)	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 3691 V and ≤ 3713 V, with internal time delay set ≥ 0.9 seconds and ≤ 1.1 seconds
b. Time Delay	2 (1 per source)	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 8.4 seconds and ≤ 9.6 seconds
5. 4 kV Emergency Bus Undervoltage (Degraded Voltage non-LOCA)			
a. Bus Undervoltage	2 (1 per source)	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 4065 V and ≤ 4089 V, with internal time delay set ≥ 0.9 seconds and ≤ 1.1 seconds
b. Time Delay	2 (1 per source)	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 57.0 seconds and ≤ 63.0 seconds

3.3 INSTRUMENTATION

3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

LCO 3.3.8.2 Two RPS electric power monitoring assemblies shall be OPERABLE for each inservice RPS motor generator set or alternate power supply.

APPLICABILITY: MODES 1 and 2,
MODES 3, 4, and 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or both inservice power supplies with one electric power monitoring assembly inoperable.	A.1	Remove associated inservice power supply(s) from service.	72 hours
B. One or both inservice power supplies with both electric power monitoring assemblies inoperable.	B.1	Remove associated inservice power supply(s) from service.	1 hour
C. Required Action and associated Completion Time of Condition A or B not met in MODE 1 or 2.	C.1	Be in MODE 3.	12 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 3, 4, or 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.	D.1	Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.8.2.1	------------------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 for each RPS motor generator set electric power monitoring assembly. The Allowable Values shall be: a. Overvoltage ≤ 133 V, with time delay set to ≤ 1.5 seconds. b. Undervoltage ≥ 111 V, with time delay set to ≤ 1.5 seconds. c. Underfrequency ≥ 56.8 Hz, with time delay set to ≤ 7.0 seconds.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.8.2.3	Perform CHANNEL CALIBRATION for each RPS alternate power supply electric power monitoring assembly. The Allowable Values shall be: a. Overvoltage ≤ 133 V, with time delay set to ≤ 1.5 seconds. b. Undervoltage ≥ 111 V, with time delay set to ≤ 4.0 seconds. c. Underfrequency ≥ 56.8 Hz, with time delay set to ≤ 1.5 seconds.	24 months
SR 3.3.8.2.4	Perform a system functional test.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.1 Recirculation Loops Operating

LCO 3.4.1 Two recirculation loops with matched flows shall be in operation with core flow as a function of THERMAL POWER in the "Unrestricted" Region of Figure 3.4.1-1.

<u>OR</u>

One recirculation loop shall be in operation with core flow as a function of THERMAL POWER in the "Unrestricted" Region of Figure 3.4 1-1 and with the following limits applied when the associated LCO is applicable:

a. LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," single loop operation limits specific in the COLR;

b. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," single loop operation limits specified in the COLR; and

c. LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," Function 2.b (Average Power Range Monitors Flow Biased High Scram), Allowable Value of Table 3.3.1.1-1 is reset for single loop operation.

---------------------------NOTE---------------------------
Required limit modifications for single recirculation loop operation may be delayed for up to 12 hours after transition from two recirculation loop operation to single recirculation loop operation.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or two recirculation loops in operation with core flow as a function of THERMAL POWER in the "Restricted" Region of Figure 3.4.1-1.	A.1	Verify APRM and LPRM neutron flux noise levels are ≤ 4% and ≤ 3 times baseline noise levels.	1 hour AND Once per 8 hours thereafter AND 1 hour after completion of any THERMAL POWER increase ≥ 5% RTP
B. Required Action and associated Completion Time of Condition A not met.	B.1	Restore APRM and LPRM neutron flux noise levels to ≤ 4% and ≤ 3 times baseline noise levels.	2 hours
C. One recirculation loop in operation with core flow ≤ 39% of rated core flow and THERMAL POWER in the "Restricted" Region of Figure 3.4.1-1.	C.1	Reduce THERMAL POWER to the "Unrestricted" Region of Figure 3.4.1-1.	4 hours
	OR		
	C.2	Increase core flow to > 39% of rated core flow.	4 hours

(continued)

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.9 RCS Pressure and Temperature (P/T) Limits

LCO 3.4.9 RCS pressure, RCS temperature, RCS heatup and cooldown rates, and the recirculation pump starting temperature requirements shall be maintained within limits.

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 3.4.9.1	-------------------NOTE------------------- Only required to be performed during RCS heatup and cooldown operations and RCS inservice leak and hydrostatic testing. ---	
	Verify: a. RCS pressure and RCS temperature are within the applicable limits specified in Figures 3.4.9-1 and 3.4.9-2; and b. RCS heatup and cooldown rates are ≤ 100°F in any 1 hour period.	30 minutes

B

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.9.2	Verify RCS pressure and RCS temperature are within the criticality limits specified in Figure 3.4.9-3.	Once within 15 minutes prior to control rod withdrawal for the purpose of achieving criticality
SR 3.4.9.3	-------------------NOTE------------------- Only required to be met in MODES 1, 2, 3, and 4 during recirculation pump start. -- 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 3.4.9.4	-------------------NOTE------------------- Only required to be met in MODES 1, 2, 3, and 4 during recirculation pump start. -- 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 3.4.9.5	-------------------NOTE------------------- Only required to be performed when tensioning the reactor vessel head bolting studs. -- Verify reactor vessel flange and head flange temperatures are > 70°F.	30 minutes
SR 3.4.9.6	-------------------NOTE------------------- Not required to be performed until 30 minutes after RCS temperature ≤ 80°F in MODE 4. -- Verify reactor vessel flange and head flange temperatures are > 70°F.	30 minutes
SR 3.4.9.7	-------------------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 > 70°F.	12 hours

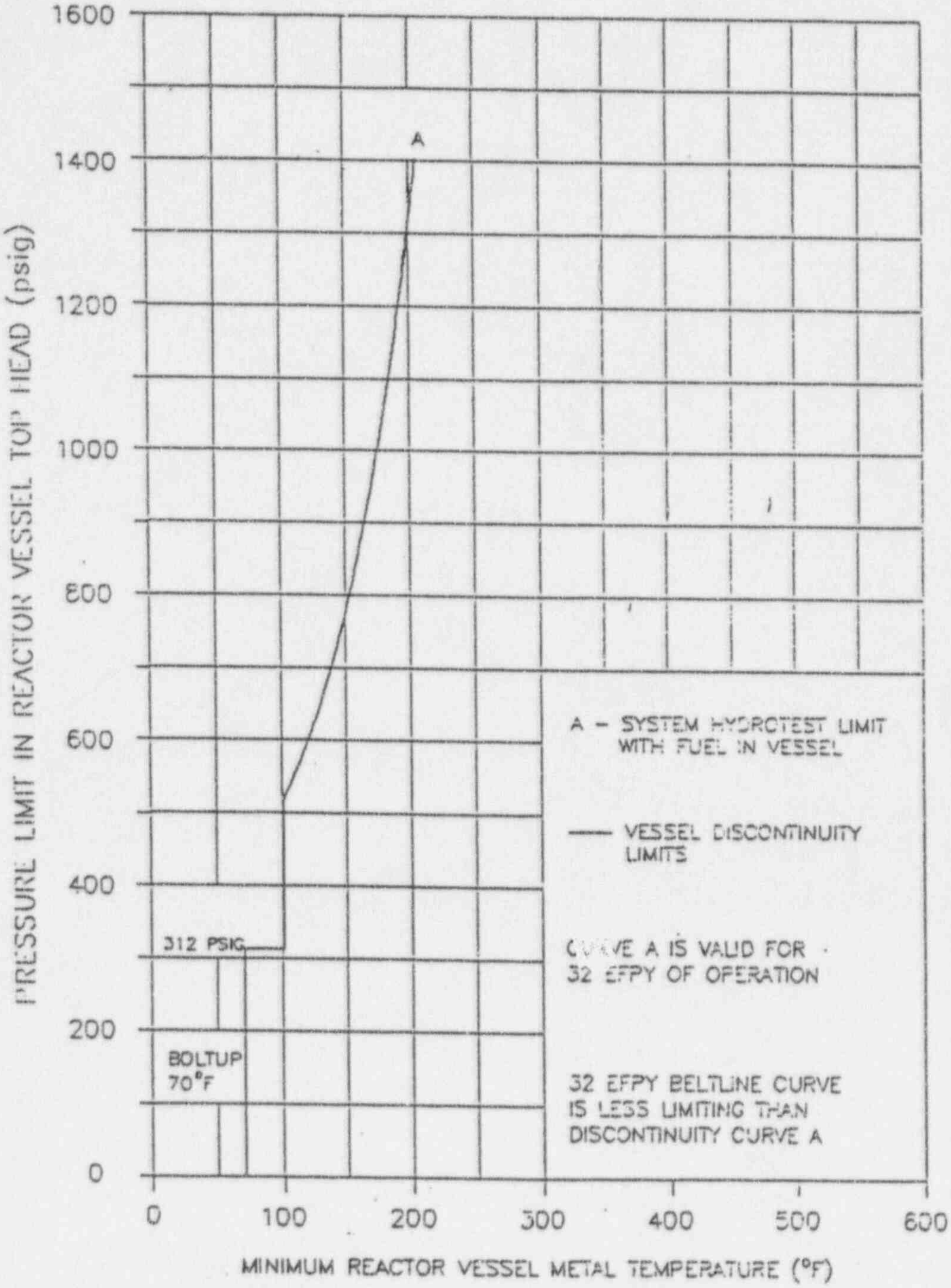

Figure 3.4.9-1 (page 1 of 1)

Temperature/Pressure Limits for
Inservice Hydrostatic and Inservice Leakage Tests

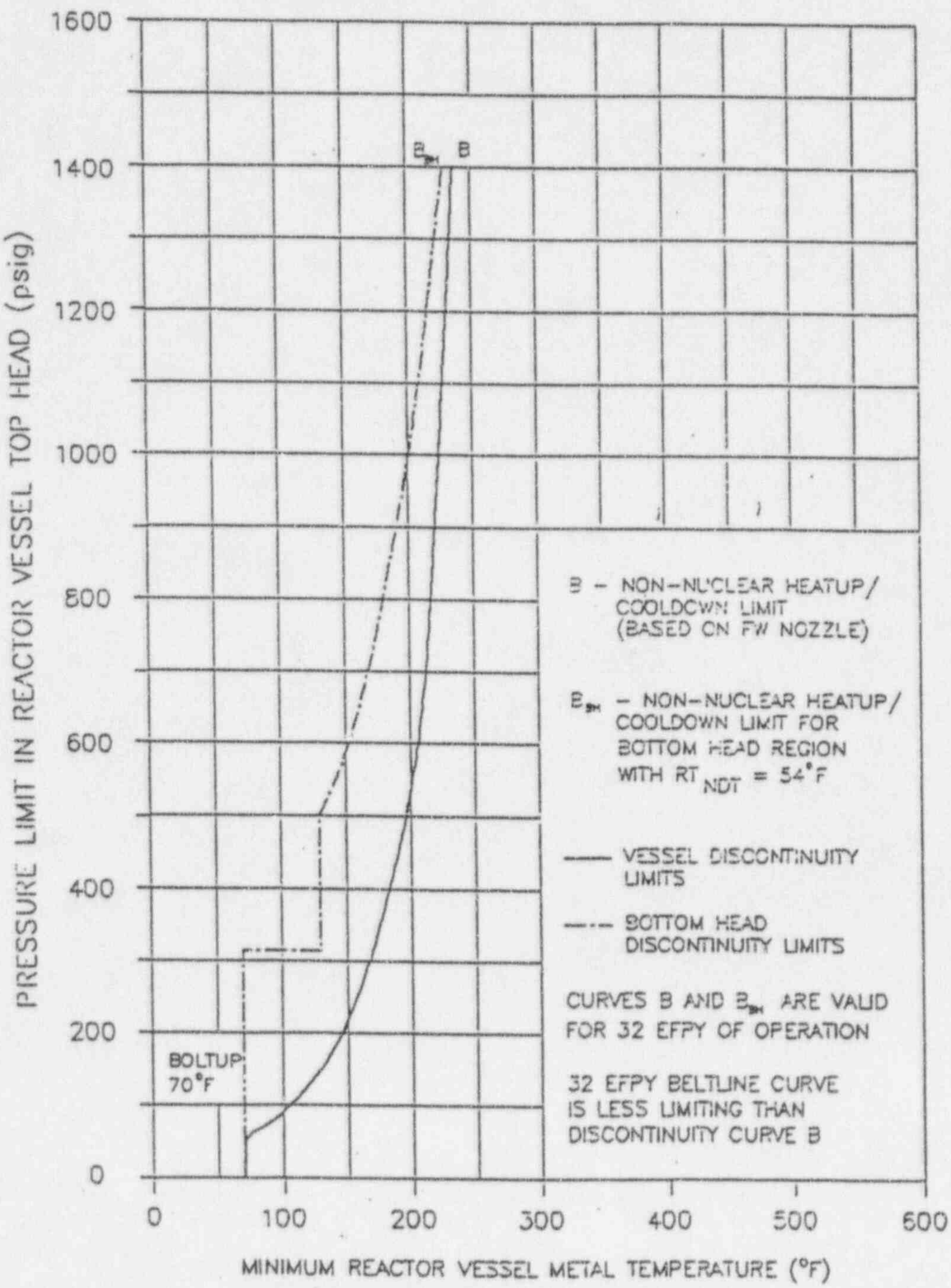

Figure 3.4.9-2 (page 1 of 1)

Temperature/Pressure Limits for
Non-Nuclear Heatup and Cooldown Following a Shutdown

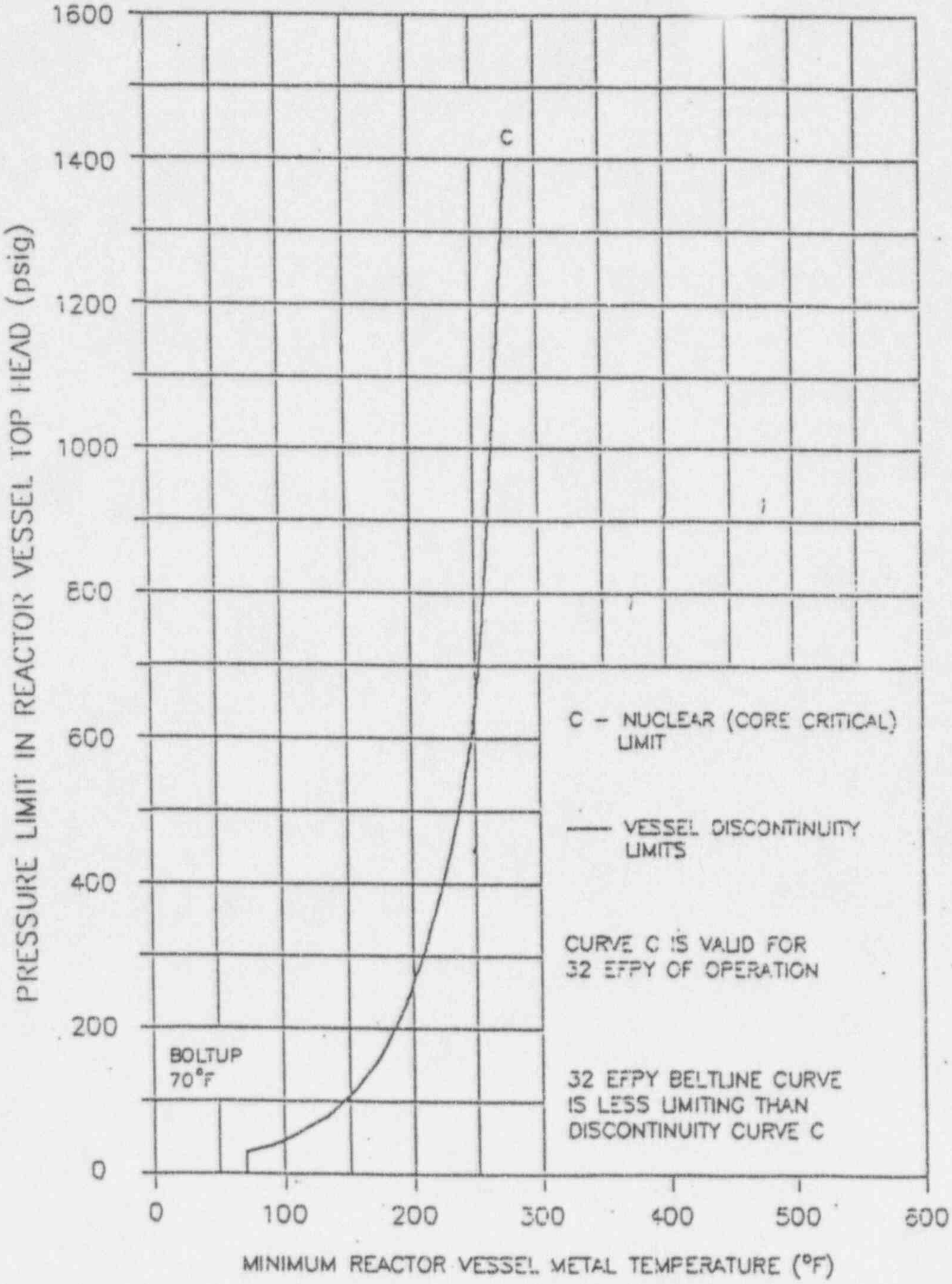

Figure 3.4.9-3 (page 1 of 1)

Temperature/Pressure Limits for Criticality

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.10 Reactor Steam Dome Pressure

LCO 3.4.10 The reactor steam dome pressure shall be ≤ 1053 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 3.4.10.1	Verify reactor steam dome pressure is ≤ 1053 psig.	12 hours

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

3.5.2 ECCS—Shutdown

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

APPLICABILITY: MODE 4,
MODE 5, except with the spent fuel storage pool gates removed, water level ≥ 458 inches above reactor pressure vessel instrument zero, and no operations with a potential for draining the reactor vessel (OPDRVs) in progress.

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 OPDRVs.	Immediately
C. Two required ECCS injection/spray subsystems inoperable.	C.1	Initiate action to suspend OPDRVs.	Immediately
	<u>AND</u>		
	C.2	Restore one ECCS injection/spray subsystem to OPERABLE status.	4 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.2.2	------------------NOTE------------------ Only required to be performed upon entry into primary containment when the primary containment is de-inerted. -- Verify only one door in the primary containment air lock can be opened at a time.	184 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources—Operating

LCO 3.8.1 The following AC electrical power sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Unit 3 Class 1E AC Electrical Power Distribution System;

b. Four diesel generators (DGs) capable of supplying the Unit 3 onsite Class 1E AC Electrical Power Distribution System;

c. The qualified circuit(s) between the offsite transmission network and the Unit 2 onsite Class 1E AC electrical power distribution subsystem(s) needed to support the Unit 2 powered equipment required to be OPERABLE by LCO 3.6.3.1, "Containment Atmospheric Dilution (CAD) System," LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," LCO 3.7.2, "Emergency Service Water (ESW) System and Normal Heat Sink," LCO 3.7.4, "Main Control Room Emergency Ventilation (MCREV) System," and LCO 3.8.4, "DC Sources—Operating"; and

d. The DG(s) capable of supplying the Unit 2 onsite Class 1E AC electrical power distribution subsystem(s) needed to support the Unit 2 powered equipment required to be OPERABLE by LCO 3.6.3.1, LCO 3.6.4.3, LCO 3.7.2, LCO 3.7.4, and LCO 3.8.4.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One offsite circuit inoperable. AND One DG inoperable.	------------NOTE------------ Enter applicable Conditions and Required Actions of LCO 3.8.7, "Distribution Systems—Operating," when Condition D is entered with no AC power source to any 4 kV emergency bus. ----------------------------	
	D.1 Restore offsite circuit to OPERABLE status.	12 hours
	OR	
	D.2 Restore DG to OPERABLE status.	12 hours
E. Two or more DGs inoperable.	E.1 Restore all but one DG to OPERABLE status.	2 hours
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. One or more offsite circuits and two or more DGs inoperable. OR Two or more offsite circuits and one DG inoperable.	G.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	-------------------NOTES-------------------- 1. If performed with the DG synchronized with offsite power, it shall be performed at a power factor ≤ 0.89. 2. A single test at the specified Frequency will satisfy this Surveillance for both units. --- Verify each DG rejects a load greater than or equal to its associated single largest post-accident load, and: a. Following load rejection, the frequency is ≤ 66.75 Hz; b. Within 1.8 seconds following load rejection, the voltage is ≥ 3750 V and ≤ 4570 V, and after steady state conditions are reached, maintains voltage ≥ 4160 V and ≤ 4400 V; and c. Within 2.4 seconds following load rejection, the frequency is ≥ 58.8 Hz and ≤ 61.2 Hz.	24 months
SR 3.8.1.10	------------------NOTE--------------------- A single test at the specified Frequency will satisfy this Surveillance for both units. --- Verify each DG operating at a power factor ≤ 0.89 does not trip and voltage is maintained ≤ 5230 V during and following a load rejection of ≥ 2400 kW and ≤ 2600 kW.	24 months

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.2 AC Sources—Shutdown

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

a. One qualified circuit between the offsite transmission network and the Unit 3 onsite Class 1E AC electrical power distribution subsystem(s) required by LCO 3.8.8, "Distribution Systems—Shutdown";

b. Two DGs each capable of supplying one Unit 3 onsite Class 1E AC electrical power distribution subsystem required by LCO 3.8.8;

c. One qualified circuit between the offsite transmission network and the Unit 2 onsite Class 1E AC electrical power distribution subsystem(s) needed to support the Unit 2 powered equipment required to be OPERABLE by LCO 3.6.4.3, "Standby Gas Treatment (SGT) System", LCO 3.7.4, "Main Control Room Emergency Ventilation (MCREV) System," and LCO 3.8.5, "DC Sources—Shutdown"; and

d. The DG(s) capable of supplying one subsystem of each of the Unit 2 powered equipment required to be OPERABLE by LCO 3.6.4.3, LCO 3.7.4, and LCO 3.8.5.

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

SURVEILLANCE REQUIREMENTS

--NOTE--
SR 3.8.4.1 through SR 3.8.4.8 are applicable only to the Unit 3 DC electrical power subsystems. SR 3.8.1.9 is applicable only to the Unit 2 DC electrical power subsystems.

	SURVEILLANCE	FREQUENCY
SR 3.8.4.1	Verify battery terminal voltage is ≥ 123.5 V on float charge.	------NOTE----- The 7 day Frequency is not applicable if the battery is on equalize charge or has been on equalize charge at any time during the previous 1 day. -------------- 7 days AND 14 days
SR 3.8.4.2	Verify no visible corrosion at battery terminals and connectors. OR Verify battery connection resistance is ≤ 40 E-6 ohms.	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 could potentially degrade battery performance.	12 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
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
SR 3.8.4.5	Verify battery connection resistance is $\leq$ 40 E-6 ohms.	12 months
SR 3.8.4.6	Verify each required battery charger supplies $\geq$ 200 amps at $\geq$ 125 V for $\geq$ 4 hours.	24 months
SR 3.8.4.7	-------------------NOTES------------------ 1. SR 3.8.4.8 may be performed in lieu of the service test in SR 3.8.4.7 once per 60 months when SR 3.8.4.8 envelops the duty cycle of the battery. 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)

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. Unit 3 Division I and Division II AC and DC electrical power distribution subsystems; and

b. Unit 2 AC and DC electrical power distribution subsystems needed to support equipment required to be OPERABLE by LCO 3.4.7, "Residual Heat Removal (RHR Shutdown Cooling System—Hot Shutdown," LCO 3.5.1, "ECCS—Operating," LCO 3.6.2.3, "RHR Suppression Pool Cooling," LCO 3.6.2.4, "RHR Suppression Pool Spray," LCO 3.6.3.1, "Containment Atmospheric Dilution (CAD) System," LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," LCO 3.7.1, "High Pressure Service Water (HPSW) System," LCO 3.7.2, "Emergency Service Water (ESW) System and Normal Heat Sink," LCO 3.7.3, "Emergency Heat Sink," LCO 3.7.4, "Main Control Room Emergency Ventilation (MCREV) System," and LCO 3.8.1, "AC Sources—Operating."

APPLICABILITY: MODES 1, 2, and 3.

5.5 Programs and Manuals (continued)

5.5.4 Radioactive Effluent Controls Program

This program conforms to 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents as low as reasonably achievable. The program 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:

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 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. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.1302 and with the methodology and parameters in the ODCM;

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 liquid radioactive effluents and determination of cumulative dose contributions from gaseous 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 effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when projected doses averaged over one month would exceed 0.12 mrem to the total body or 0.4 mrem to any organ (combined total from the two reactors at the site); B

g. Limitations to ensure gaseous effluents shall be processed, prior to release, through the appropriate gaseous effluent treatment systems as described in the ODCM;

(continued)

5.5 Programs and Manuals

5.5.4 Radioactive Effluent Controls Program (continued)

h. Limitations on the dose rate resulting from radioactive material released in gaseous effluents to areas beyond the site boundary shall be limited to the following:

1. For noble gases: less than or equal to a dose rate of 500 mrems/yr to the total body and less than or equal to a dose rate of 3000 mrems/yr to the skin, and

2. For iodine-131, iodine-133, tritium, and for all radionuclides in particulate form with half lives > 8 days: less than or equal to a dose rate of 1500 mrems/yr to any organ;

i. Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I;

j. Limitations on the annual and quarterly doses to a member of the public from iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half lives > 8 days in gaseous effluents released from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I; and

k. Limitations on the annual dose or dose commitment to any member of the public due to releases of radioactivity and to radiation from uranium fuel cycle sources, conforming to 40 CFR 190.

5.5.5 Component Cyclic or Transient Limit

This program provides controls to track the UFSAR, Table 4.2.4, cyclic and transient occurrences to ensure that components are maintained within the design limits.

(continued)

5.5 Programs and Manuals (continued)

5.5.6 Inservice Testing Program

This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components including applicable supports. The program shall include the following:

a. Testing frequencies specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda are as follows:

ASME Boiler and Pressure Vessel Code and applicable Addenda terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 732 days

b. The provisions of SR 3.0.2 are applicable to the Frequencies for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any TS.

5.5.7 Ventilation Filter Testing Program (VFTP)

The VFTP shall establish the required testing of Engineered Safety Feature (ESF) filter ventilation systems.

Tests described in Specifications 5.5.7.a, 5.5.7.b, and 5.5.7.c shall be performed:

(continued)

5.5 Programs and Manuals

5.5.7 Ventilation Filter Testing Program (VFTP) (continued)

1) Once per 12 months for standby service or after 720 hours of system operation; and,

2) After each complete or partial replacement of the HEPA filter train or charcoal adsorber filter; 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 Specifications 5.5.7.d and 5.5.7.e shall be performed once per 24 months.

The test described in Specification 5.5.7.f shall be performed once per 12 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 HEPA filters shows a penetration and system bypass < 0.05% when tested in accordance with Regulatory Guide 1.52, Revision 2, Section 5c, and ASME N510-1989, Sections 6 (Standby Gas Treatment (SGT) System only) and 10, at the system flowrate specified below.

ESF Ventilation System	Flowrate (cfm)
SGT System	7200 to 8800
Main Control Room Emergency Ventilation (MCREV) System	2700 to 3300

(continued)

5.5 Programs and Manuals

5.5.7 Ventilation Filter Testing Program (VFTP) (continued)

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, Section 5d, and ASME N510-1989, Sections 6 (SGT System only) and 11, at the system flowrate specified below.

ESF Ventilation System	Flowrate (cfm)
SGT System	7200 to 8800
MCREV System	2700 to 3300

c. Demonstrate for each of the ESF systems that a laboratory test of a sample of the charcoal adsorber, when obtained as described in Regulatory Guide 1.52, Revision 2, Section 6b, shows the methyl iodide penetration less than the value specified below when tested at the conditions specified below.

	ESF Ventilation System	
	SGT System	MCREV System
Methyl iodide removal rate: (%)	≥ 95	≥ 90
Methyl iodide concentration: (mg/m^3)	0.5 to 1.5	0.05 to 0.15
Flow rate: (% design flow)	80 to 120	80 to 120
Temperature: (degrees F)	≥ 190	≥ 125
Relative Humidity: (%)	≥ 70	≥ 95

(continued)

5.5 Programs and Manuals

5.5.7 Ventilation Filter Testing Program (VFTP) (continued)

d. Demonstrate for each of the ESF systems that the pressure drop across the combined HEPA filters, the prefilters (if installed), 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	< 3.9	7200 to 8800
MCREV System	< 8	2700 to 3300

e. Demonstrate that the heaters for the SGT System dissipate ≥ 40 kw.

5.5.8 Explosive Gas Monitoring Program

This program provides controls for potentially explosive gas mixtures contained downstream of the off-gas recombiners.

The program shall include:

a. The limit for the concentration of hydrogen downstream of the off-gas recombiners and a surveillance program to ensure the limit is maintained. This limit shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion);

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas Monitoring Program surveillance frequencies.

5.5.9 Diesel Fuel Oil Testing Program

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

(continued)

5.5 Programs and Manuals

5.5.9 Diesel Fuel Oil Testing Program (continued)

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

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

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

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

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 is ≤ 10 mg/l when tested every 31 days in accordance with ASTM D2276, Method A, except that the filters specified in the ASTM method may have a nominal pore size of up to three (3) microns.

5.5.10 Technical Specifications (TS) Bases Control Program

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

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

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

   A change in the TS incorporated in the license; or

   A change to the UFSAR 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 UFSAR.

(continued)

5.5 Programs and Manuals

5.5.10 Technical Specifications (TS) Bases Control Program (continued)

d. Proposed changes that meet the criteria of 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).

5.5.11 Safety Function Determination Program (SFDP)

This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate limitations and remedial or compensatory actions may be identified to be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6.

a. The SFDP shall contain the following:

   1. Provisions for cross division checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

   2. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

   3. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

   4. Other appropriate limitations and remedial or compensatory actions.

b. A loss of safety function exists when, assuming no concurrent single failure, a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

(continued)

5.5 Programs and Manuals

5.5.11 Safety Function Determination Program (SFDP) (continued)

1. A required system redundant to system(s) supported by the inoperable support system is also inoperable; or

2. A required system redundant to system(s) in turn supported by the inoperable supported system is also inoperable; or

3. A required system redundant to support system(s) for the supported systems (b.1) and (b.2) above is also inoperable.

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

5.0 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

-----NOTE-----
A single submittal may be made for a multiple unit station. The submittal should combine sections common to all units at the station.

A tabulation on an annual basis of the number of station, utility, and other personnel (including contractors) receiving an annual deep dose equivalent > 100 mrem and the associated collective deep dose equivalent (reported in person-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 pocket dosimeter, thermoluminescence 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 deep dose equivalent received from external sources should be assigned to specific major work functions. The report shall be submitted by March 31 of each year.

5.6.2 Annual Radiological Environmental Operating Report

-----NOTE-----
A single submittal may be made for a multiple unit station. The submittal should combine sections common to all units at the station.

The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted by May 31 of each year. The report shall include summaries, interpretations, and analyses of trends of the results of the radiological environmental monitoring activities 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.

(continued)

5.6 Reporting Requirements

5.6.2 Annual Radiological Environmental Operating Report (continued)

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

5.6.3 Radioactive Effluent Release Report

-----NOTE-----
A single submittal may be made for a multiple unit station. The submittal should combine sections common to all units at the station.

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

5.6.4 Monthly Operating Reports

Routine reports of operating statistics and shutdown experience shall be submitted on a monthly basis no later than the 15th of each month following the calendar month covered by the report.

(continued)

5.6 Reporting Requirements (continued)

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 Average Planar Linear Heat Generation Rate for Specification 3.2.1;

   2. The Minimum Critical Power Ratio for Specifications 3.2.2 and 3.3.2.1;

   3. The Linear Heat Generation Rate for Specification 3.2.3; and

   4. The Control Rod Block Instrumentation for Specification 3.3.2.1.

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

   1. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel" (latest approved version as specified in the COLR);

   2. NEDC-32162P, "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Peach Bottom Atomic Power Station Units 2 and 3," Revision 1, February, 1993;

   3. PECo-FMS-0001-A, "Steady-State Thermal Hydraulic Analysis of Peach Bottom Units 2 and 3 using the FIBWR Computer Code";

   4. PECo-FMS-0002-A, "Method for Calculating Transient Critical Power Ratios for Boiling Water Reactors (RETRAN-TCPPECo)";

   5. PECo-FMS-0003-A, "Steady-State Fuel Performance Methods Report";

   6. PECo-FMS-0004-A, "Methods for Performing BWR Systems Transient Analysis";

(continued)

5.6 Reporting Requirements

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

7. PECo-FMS-0005-A, "Methods for Performing BWR Steady-State Reactor Physics Analysis"; and

8. PECo-FMS-0006-A, "Methods for Performing BWR Reload Safety Evaluations."

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 Areas

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 <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>

a. Each accessible 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. 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 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:

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

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, or

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

(continued)

5.7 High Radiation Areas

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

4. A direct-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.

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

a. Each accessible 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 radiation protection personnel.

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

(continued)

5.7 High Radiation Areas

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:

1. An alarming dosimeter with an appropriate alarm setpoint, or

2. A radiation monitoring device that continuously transmits dose rate or cumulative dose information 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, or

3. A direct-reading dosimeter and,

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

(continued)

5.7 High Radiation Areas

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

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

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

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

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BASES

APPLICABLE SAFETY ANALYSES

2.1.1.2 MCPR (continued)

the fuel cladding integrity SL is defined as the critical power ratio in the limiting fuel assembly for which more than 99.9% of the fuel rods in the core are expected to avoid boiling transition, considering the power distribution within the core and all uncertainties.

The MCPR SL is determined using a statistical model that combines all the uncertainties in operating parameters and the procedures used to calculate critical power. The probability of the occurrence of boiling transition is determined using the approved General Electric Critical Power correlations. Details of the fuel cladding integrity SL calculation are given in Reference 4. Reference 4 also includes a tabulation of the uncertainties used in the determination of the MCPR SL and of the nominal values of the parameters used in the MCPR SL statistical analysis. In addition to being applicable to GE fuel, the MCPR Safety Limit is also applicable to the QFBs manufactured by GE, ABB Atom, and SPC as justified in References 1, 2, and 3 respectively.

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 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. The core can be adequately cooled as long as water level is above ⅔ 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.

(continued)

BASES

ACTIONS

A.1, A.2, A.3, and A.4 (continued)

another pair of "slow" control rods adjacent to one another. The description of "slow" control rods is provided in LCO 3.1.4, "Control Rod Scram Times." In addition, the associated control rod drive must be disarmed in 2 hours. The allowed Completion Time of 2 hours is acceptable, considering the reactor can still be shut down, assuming no additional control rods fail to insert, and provides a reasonable time to perform the Required Action in an orderly manner. The control rod must be isolated from both scram and normal insert and withdraw pressure. Isolating the control rod from scram and normal insert and withdraw pressure prevents damage to the CRDM. The control rod should be isolated from scram and normal insert and withdraw pressure, while maintaining cooling water to the CRD.

Monitoring of the insertion capability of each withdrawn control rod must also be performed within 24 hours from discovery of Condition A concurrent with THERMAL POWER greater than the low power setpoint (LPSP) of the RWM. SR 3.1.3.2 and SR 3.1.3.3 perform periodic tests of the control rod insertion capability of withdrawn control rods. Testing each withdrawn control rod ensures that a generic problem does not exist. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." The Required Action A.3 Completion Time only begins upon discovery of Condition A concurrent with THERMAL POWER greater than the actual LPSP of the RWM, since the notch insertions may not be compatible with the requirements of rod pattern control (LCO 3.1.6) and the RWM (LCO 3.3.2.1). The allowed Completion Time of 24 hours from discovery of Condition A concurrent with THERMAL POWER greater than the LPSP of the RWM provides a reasonable time to test the control rods, considering the potential for a need to reduce power to perform the tests.

To allow continued operation with a withdrawn control rod stuck, an evaluation of adequate SDM is also required within 72 hours. Should a DBA or transient require a shutdown, to preserve the single failure criterion, an additional control rod would have to be assumed to fail to insert when required. Therefore, the original SDM demonstration may not be valid. The SDM must therefore be evaluated (by measurement or analysis) with the stuck control rod at its stuck position and the highest worth OPERABLE control rod assumed to be fully withdrawn.

(continued)

BASES

ACTIONS

A.1, A.2, A.3, and A.4 (continued)

The allowed Completion Time of 72 hours to verify SDM is adequate, considering that with a single control rod stuck in a withdrawn position, the remaining OPERABLE control rods are capable of providing the required scram and shutdown reactivity. Failure to reach MODE 4 is only likely if an additional control rod adjacent to the stuck control rod also fails to insert during a required scram. Even with the postulated additional single failure of an adjacent control rod to insert, sufficient reactivity control remains to reach and maintain MODE 3 conditions (Ref. 5).

B.1

With two or more withdrawn control rods stuck, the plant must be brought to MODE 3 within 12 hours. The occurrence of more than one control rod stuck at a withdrawn position increases the probability that the reactor cannot be shut down if required. Insertion of all insertable control rods eliminates the possibility of an additional failure of a control rod to insert. 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.

C.1 and C.2

With one or more control rods inoperable for reasons other than being stuck in the withdrawn position, operation may continue, provided the control rods are fully inserted within 3 hours and disarmed (electrically or hydraulically) within 4 hours. Inserting a control rod ensures the shutdown and scram capabilities are not adversely affected. The control rod is disarmed to prevent inadvertent withdrawal during subsequent operations. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. The control rods can be electrically disarmed by disconnecting power from all four directional control valve solenoids. Required Action C.1 is modified by a Note, which allows the RWM to be bypassed if required to allow insertion of the inoperable control rods and continued operation. LCO 3.3.2.1 provides additional requirements when the RWM is bypassed to ensure compliance with the CRDA analysis.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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

D.1 and D.2

Out of sequence control rods may increase the potential reactivity worth of a dropped control rod during a CRDA. At ≤ 10% RTP, the generic banked position withdrawal sequence (BPWS) analysis (Ref. 5) requires inserted control rods not in compliance with BPWS to be separated by at least two OPERABLE control rods in all directions, including the diagonal. Therefore, if two or more inoperable control rods are not in compliance with BPWS and not separated by at least two OPERABLE control rods, action must be taken to restore compliance with BPWS or restore the control rods to OPERABLE status. Condition D is modified by a Note indicating that the Condition is not applicable when > 10% RTP, since the BPWS is not required to be followed under these conditions, as described in the Bases for LCO 3.1.6. The allowed Completion Time of 4 hours is acceptable, considering the low probability of a CRDA occurring.

E.1

If any Required Action and associated Completion Time of Condition A, C, or D are not met, or there are nine or more inoperable control rods, 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. This ensures all insertable control rods are inserted and places the reactor in a condition that does not require the active function (i.e., scram) of the control rods. The number of control rods permitted to be inoperable when operating above 10% RTP (e.g., no CRDA considerations) could be more than the value specified, but the occurrence of a large number of

(continued)

BASES

ACTIONS

E.1 (continued)

inoperable control rods could be indicative of a generic problem, and investigation and resolution of the potential problem should be undertaken. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

The position of each control rod must be determined to ensure adequate information on control rod position is available to the operator for determining control rod OPERABILITY and controlling rod patterns. Control rod position may be determined by the use of OPERABLE position indicators, by moving control rods to a position with an OPERABLE indicator, or by the use of other appropriate methods. The 24 hour Frequency of this SR is based on operating experience related to expected changes in control rod position and the availability of control rod position indications in the control room.

SR 3.1.3.2 and SR 3.1.3.3

Control rod insertion capability is demonstrated by inserting each partially or fully withdrawn control rod at least one notch and observing that the control rod moves. The control rod may then be returned to its original position. This ensures the control rod is not stuck and is free to insert on a scram signal. These Surveillances are not required when THERMAL POWER is less than or equal to the actual LPSP of the RWM, since the notch insertions may not be compatible with the requirements of the Banked Position Withdrawal Sequence (BPWS) (LCO 3.1.6) and the RWM (LCO 3.3.2.1). The 7 day Frequency of SR 3.1.3.2 is based on operating experience related to the changes in CRD performance and the ease of performing notch testing for fully withdrawn control rods. Partially withdrawn control rods are tested at a 31 day Frequency, based on the potential power reduction required to allow the control rod movement and considering the large testing sample of SR 3.1.3.2. Furthermore, the 31 day Frequency takes into account operating experience related to changes in CRD performance. At any time, if a control rod is immovable, a

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.3.2 and SR 3.1.3.3 (continued)

determination of that control rod's trippability (OPERABILITY) must be made and appropriate action taken. For example, the unavailability of the Reactor Manual Control System does not affect the OPERABILITY of the control rods, provided SR 3.1.3.2 and SR 3.1.3.3 are current in accordance with SR 3.0.2.

SR 3.1.3.4

Verifying that the scram time for each control rod to notch position 06 is ≤ 7 seconds provides reasonable assurance that the control rod will insert when required during a DBA or transient, thereby completing its shutdown function. This SR is performed in conjunction with the control rod scram time testing of SR 3.1.4.1, SR 3.1.4.2, SR 3.1.4.3, and SR 3.1.4.4. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and the functional testing of SDV vent and drain valves in LCO 3.1.8, "Scram Discharge Volume (SDV) Vent and Drain Valves," overlap this Surveillance to provide complete testing of the assumed safety function. The associated Frequencies are acceptable, considering the more frequent testing performed to demonstrate other aspects of control rod OPERABILITY and operating experience, which shows scram times do not significantly change over an operating cycle.

SR 3.1.3.5

Coupling verification is performed to ensure the control rod is connected to the CRDM and will perform its intended function when necessary. The Surveillance requires verifying a control rod does not go to the withdrawn overtravel position. The overtravel position feature provides a positive check on the coupling integrity since only an uncoupled CRD can reach the overtravel position. The verification is required to be performed any time a control rod is withdrawn to the "full out" position (notch position 48) or prior to declaring the control rod OPERABLE after work on the control rod or CRD System that could affect coupling (CRD changeout and blade replacement or complete cell disassembly, i.e., guide tube removal). This includes control rods inserted one notch and then returned

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.1.3.5 (continued) to the "full out" position during the performance of SR 3.1.3.2. This Frequency is acceptable, considering the low probability that a control rod will become uncoupled when it is not being moved and operating experience related to uncoupling events.
REFERENCES	1. UFSAR, Sections 1.5.1.1 and 1.5.2.2. 2. UFSAR, Section 14.6.2. 3. UFSAR, Appendix K, Section VI. 4. UFSAR, Chapter 14. 5. NEDO-21231, "Banked Position Withdrawal Sequence," Section 7.2, January 1977.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.13 (continued)

If any bypass channel's setpoint is nonconservative (i.e., the Functions are bypassed at ≥ 30% RTP, either due to open main turbine bypass valve(s) or other reasons), then the affected Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel is considered OPERABLE.

The Frequency of 24 months is based on engineering judgment and reliability of the components.

SR 3.3.1.1.17

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional testing of control rods (LCO 3.1.3), and SDV vent and drain valves (LCO 3.1.8), 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 will pass the Surveillance when performed at the 24 month Frequency.

SR 3.3.1.1.18

This SR ensures that the individual channel response times are maintained less than or equal to the original design value. The RPS RESPONSE TIME acceptance criterion is included in Reference 11.

B

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.18 (continued)

RPS RESPONSE TIME tests are conducted on a 24 month Frequency. The 24 month Frequency is consistent with the PBAPS 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 occurrences.

REFERENCES

1. UFSAR, Section 7.2.
2. UFSAR, Section Chapter 14.
3. NEDO-23842, "Continuous Control Rod Withdrawal in the Startup Range," April 18, 1978.
4. NEDC-32183P, "Power Rerate Safety Analysis Report for Peach Bottom 2 & 3," dated May 1993.
5. UFSAR, Section 14.6.2.
6. UFSAR, Section 14.5.4.
7. UFSAR, Section 14.5.1.
8. P. Check (NRC) letter to G. Lainas (NRC), "BWR Scram Discharge System Safety Evaluation," December 1, 1980.
9. NEDO-30851-P-A , "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.
10. MDE-87-0485-1, "Technical Specification Improvement Analysis for the Reactor Protection System for Peach Bottom Atomic Power Station Units 2 and 3," October 1987.
11. UFSAR, Section 7.2.3.9.

BASES

ACTIONS

A.1 (continued)

automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

If a channel has not been restored to OPERABLE status in 30 days, this Required Action specifies initiation of action 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 action is appropriate in lieu of a shutdown requirement, since alternative actions are identified before loss of functional capability, and given the likelihood of plant conditions that would require information provided by this instrumentation.

C.1

When one or more Functions have two required channels that are inoperable (i.e., two channels inoperable in the same Function), 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.

(continued)

BASES

ACTIONS (continued)

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.

E.1

For the majority of Functions in Table 3.3.3.1-1, if the Required Action and associated Completion Time of Condition C is not met, the plant must be brought to a MODE in which the LCO not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

F.1

Since alternate means of monitoring drywell high range 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

parameter exceeds the setpoint, the associated device (e.g., internal relay contact) changes state. The Allowable Values are derived from the limiting values of the process parameters obtained from the safety analysis and corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, and instrument drift are accounted for.

The specific Applicable Safety Analyses, LCO, and Applicability discussions for Unit 2 LOP instrumentation are listed below on a Function by Function basis.

In addition, since some equipment required by Unit 2 is powered from Unit 3 sources, the Unit 3 LOP instrumentation supporting the required sources must also be OPERABLE. The OPERABILITY requirements for the Unit 3 LOP instrumentation is the same as described in this section, except Function 4 (4 kV Emergency Bus Undervoltage, Degraded Voltage LOCA) is not required to be OPERABLE, since this Function is related to a LOCA on Unit 3 only. The Unit 3 instrumentation is listed in Unit 3 Table 3.3.8.1-1.

1. 4 kV Emergency Bus Undervoltage (Loss of Voltage)

When both offsite sources are lost, a loss of voltage condition on a 4 kV emergency bus indicates that the respective emergency bus 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. This ensures that adequate power will be available to the required equipment.

The single channel of 4 kV Emergency Bus Undervoltage (Loss of Voltage) Function per associated emergency bus is only required to be OPERABLE when the associated DG and offsite circuit are required to be OPERABLE. This ensures no single instrument failure can preclude the start of three of four DGs. (One channel inputs to each of the four DGs.) Refer to LCO 3.8.1, "AC Sources—Operating," and 3.8.2, "AC Sources—Shutdown," for Applicability Bases for the DGs. B

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2., 3., 4., 5. 4 kV Emergency Bus Undervoltage (Degraded Voltage) (continued)

Two channels (one channel per source) of 4 kV Emergency Bus Undervoltage (Degraded Voltage) per Function (Functions 2, 3, 4, and 5) per associated bus are only required to be OPERABLE when the associated DG and offsite circuit are required to be OPERABLE. This ensures no single instrument failure can preclude the start of three of four DGs (each logic inputs to each of the four DGs). Refer to LCO 3.8.1 and LCO 3.8.2 for Applicability Bases for the DGs.

ACTIONS

A Note has been provided (Note 1) 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.

A.1

Pursuant to LCO 3.0.6, the AC Sources—Operating ACTIONS would not have to be entered even if the LOP instrumentation inoperability resulted in an inoperable offsite circuit. Therefore, the Required Action of Condition A is modified by a Note to indicate that when performance of a Required Action results in the inoperability of an offsite circuit, Actions for LCO 3.8.1, "AC Sources—Operating," must be immediately entered. A Unit 2 offsite circuit is considered to be inoperable if it is not supplying or not capable of supplying (due to loss of autotransfer capability) at least three Unit 2 4 kV emergency buses when the other offsite circuit is providing power or capable of supplying power to all four Unit 2 4 kV emergency buses. A Unit 2 offsite circuit is also considered to be inoperable if the Unit 2

(continued)

BASES

ACTIONS

A.1 (continued)

4 kV emergency buses being powered or capable of being powered from the two offsite circuits are all the same when at least one of the two circuits does not provide power or is not capable of supplying power to all four Unit 2 4 kV emergency buses. Inoperability of a Unit 3 offsite circuit is the same as described for a Unit 2 offsite circuit, except that the circuit path is to the Unit 3 4 kV emergency buses required to be OPERABLE by LCO 3.8.7, "Distribution Systems—Operating." The Note allows Condition A to provide requirements for the loss of a LOP instrumentation channel without regard to whether an offsite circuit is rendered inoperable. LCO 3.8.1 provides appropriate restriction for an inoperable offsite circuit.

Required Action A.1 is applicable when one 4 kV emergency bus has one or two required Function 3 (Degraded Voltage High Setting) channels inoperable or when one 4 kV emergency bus has one or two required Function 5 (Degraded Voltage Non-LOCA) channels inoperable. In this Condition, the affected Function may not be capable of performing its intended function automatically for these buses. However, the operators would still receive indication in the control room of a degraded voltage condition on the unaffected buses and a manual transfer of the affected bus power supply to the alternate source could be made without damaging plant equipment. Therefore, Required Action A.1 allows 14 days to restore the inoperable channel(s) to OPERABLE status or place the inoperable channel(s) in trip. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore design trip capability to the LOP instrumentation, and allow operation to continue. Alternatively, 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 DG initiation), Condition D must be entered and its Required Action taken.

The 14 day Completion Time is intended to allow time to restore the channel(s) to OPERABLE status. The Completion Time takes into consideration the diversity of the Degraded Voltage Functions, the capabilities of the remaining OPERABLE LOP Instrumentation Functions on the affected 4 kV emergency bus and on the other 4 kV emergency buses (only one 4 kV emergency bus is affected by the inoperable channels), the fact that the Degraded Voltage High Setting

(continued)

BASES

ACTIONS

A.1 (continued)

and Degraded Voltage Non-LOCA Functions provide only a marginal increase in the protection provided by the voltage monitoring scheme, the low probability of the grid operating in the voltage band protected by these Functions, and the ability of the operators to perform the Functions manually.

B.1

Pursuant to LCO 3.0.6, the AC Sources—Operating ACTIONS would not have to be entered even if the LOP instrumentation inoperability resulted in an inoperable offsite circuit. Therefore, the Required Action of Condition B is modified by a Note to indicate that when performance of a Required Action results in the inoperability of an offsite circuit, Actions for LCO 3.8.1, "AC Sources—Operating," must be immediately entered. A Unit 2 offsite circuit is considered to be inoperable if it is not supplying or not capable of supplying (due to loss of autotransfer capability) at least three Unit 2 4 kV emergency buses when the other offsite circuit is providing power or capable of supplying power to all four Unit 2 4 kV emergency buses. A Unit 2 offsite circuit is also considered to be inoperable if the Unit 2 4 kV emergency buses being powered or capable of being powered from the two offsite circuits are all the same when at least one of the two circuits does not provide power or is not capable of supplying power to all four Unit 2 4 kV emergency buses. Inoperability of a Unit 3 offsite circuit is the same as described for a Unit 2 offsite circuit, except that the circuit path is to the Unit 3 4 kV emergency buses required to be OPERABLE by LCO 3.8.7, "Distribution Systems - Operating." This allows Condition B to provide requirements for the loss of a LOP instrumentation channel without regard to whether an offsite circuit is rendered inoperable. LCO 3.8.1 provides appropriate restriction for an inoperable offsite circuit.

Required Action B.1 is applicable when two 4 kV emergency buses have one required Function 3 (Degraded Voltage High Setting) channel inoperable, or when two 4 kV emergency buses have one required Function 5 (Degraded Voltage Non-LOCA) channel inoperable, or when one 4 kV emergency bus has one required Function 3 channel inoperable and a different 4 kV emergency bus has one required Function 5 channel inoperable. In this Condition, the affected Function may

(continued)

BASES

ACTIONS

B.1 (continued)

not be capable of performing its intended function automatically for these buses. However, the operators would still receive indication in the control room of a degraded voltage condition on the unaffected buses and a manual transfer of the affected bus power supply to the alternate source could be made without damaging plant equipment. Therefore, Required Action B.1 allows 24 hours to restore the inoperable channels to OPERABLE status or place the inoperable channels in trip. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore design trip capability to the LOP instrumentation, and allow operation to continue. Alternatively, 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 DG initiation), Condition D must be entered and its Required Action taken.

The 24 hour Completion Time is intended to allow time to restore the channel(s) to OPERABLE status. The Completion Time takes into consideration the diversity of the Degraded Voltage Functions, the capabilities of the remaining OPERABLE LOP Instrumentation Functions on the affected 4 kV emergency buses and on the other 4 kV emergency buses (only two 4 kV emergency buses are affected by the inoperable channels), the fact that the Degraded Voltage High Setting and Degraded Voltage Non-LOCA Functions provide only a marginal increase in the protection provided by the voltage monitoring scheme, the low probability of the grid operating in the voltage band protected by these Functions, and the ability of the operators to perform the Functions manually.

C.1

Pursuant to LCO 3.0.6, the AC Sources—Operating ACTIONS would not have to be entered even if the LOP Instrumentation inoperability resulted in an inoperable offsite circuit. Therefore, the Required Action of Condition C is modified by a Note to indicate that when performance of the Required Action results in the inoperability of an offsite circuit, Actions for LCO 3.8.1, "AC Sources—Operating," must be immediately entered. A Unit 2 offsite circuit is considered to be inoperable if it is not supplying or not capable of supplying (due to loss of autotransfer capability) at least three Unit 2 4 kV emergency buses when

(continued)

BASES

ACTIONS

C.1 (continued)

the other offsite circuit is providing power or capable of supplying power to all four Unit 2 4 kV emergency buses. A Unit 2 offsite circuit is also considered to be inoperable if the Unit 2 4 kV emergency buses being powered or capable of being powered from the two offsite circuits are all the same when at least one of the two circuits does not provide power or is not capable of supplying power to all four Unit 2 4 kV emergency buses. Inoperability of a Unit 3 offsite circuit is the same as described for a Unit 2 offsite circuit, except that the circuit path is to the Unit 3 4 kV emergency buses required to be OPERABLE by LCO 3.8.7, "Distribution Systems - Operating." The Note allows Condition C to provide requirements for the loss of a LOP instrumentation channel without regard to whether an offsite circuit is rendered inoperable. LCO 3.8.1 provides appropriate restriction for an inoperable offsite circuit.

Required Action C.1 is applicable when one or more 4 kV emergency buses have one or more required Function 1, 2, or 4 (the Loss of Voltage, the Degraded Voltage Low Setting, and the Degraded Voltage LOCA Functions, respectively) channels inoperable, or when one 4 kV emergency bus has one required Function 3 (Degraded Voltage High Setting) channel and one required Function 5 (Degraded Voltage Non-LOCA) channel inoperable, or when any combination of three or more required Function 3 and Function 5 channels are inoperable. In this Condition, the affected Function may not be capable of performing the intended function and the potential consequences associated with the inoperable channel(s) are greater than those resulting from Condition A or Condition B. 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 design trip capability to the LOP instrumentation, 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 DG initiation), Condition D must be entered and its Required Action taken. B

(continued)

BASES

ACTIONS

C.1 (continued)

The Completion Time is based on the potential consequences associated with the inoperable channel(s) and is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

B

D.1

If any Required Action and associated Completion Time are not met, the associated Function is not capable of performing the intended function. Therefore, the associated DG(s) is declared inoperable immediately. This requires entry into applicable Conditions and Required Actions of LCO 3.8.1 and LCO 3.8.2, which provide appropriate actions for the inoperable DG(s).

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each Unit 2 LOP instrumentation Function are located in the SRs column of Table 3.3.8.1-1. SR 3.3.8.1.5 is applicable only to the Unit 3 LOP instrumentation.

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 2 hours provided: (a) for Function 1, the associated Function maintains initiation capability for three DGs; and (b) for Functions 2, 3, 4, 5, the associated Function maintains undervoltage transfer capability for three 4 kV emergency buses. The loss of function for one DG or undervoltage transfer capability for the 4 kV emergency bus for this short period is appropriate since only three of four DGs are required to start within the required times and because there is no appreciable impact on risk. Also, upon completion of the Surveillance, or expiration of the 2 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.1.1 and SR 3.3.8.1.3

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.

The Frequency of 31 days is based on operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one degraded voltage channel of a given Function in any 31 day interval is a rare event. The Frequency of 24 months is based on operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of the loss of voltage channel in any 24 month interval is a rare event.

SR 3.3.8.1.2

A CHANNEL CALIBRATION is a complete check of the relay circuitry and associated time delay relays. 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 assumptions of the current plant specific setpoint methodology.

The 18 month Frequency for the degraded voltage Functions is based upon the assumption 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.1.5

With the exception of this Surveillance, all other Surveillances of this Specification (SR 3.3.8.1.1 through SR 3.3.8.1.4) are applied only to the Unit 2 LOP instrumentation. This Surveillance is provided to direct that the appropriate Surveillances for the required Unit 3 LOP instrumentation are governed by the Unit 3 Technical Specifications. Performance of the applicable Unit 3 Surveillances will satisfy Unit 3 requirements, as well as satisfying this Unit 2 Surveillance Requirement.

The Frequency required by the applicable Unit 3 SR also governs performance of that SR for Unit 2.

REFERENCES

1. UFSAR, Chapter 14.

B 3.3 INSTRUMENTATION

B 3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

BASES

BACKGROUND

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 of the essential safety circuits. Some of the essential equipment powered from the RPS buses includes the RPS logic and scram solenoids.

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 in series 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, 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 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 if in service. Each of these circuit breakers has an associated independent set

(continued)

BASES

BACKGROUND (continued)

of Class 1E overvoltage, undervoltage, underfrequency relays, time delay relays (MG sets only), and sensing logic. Together, a circuit breaker, its associated relays, and sensing logic constitute an electric power monitoring assembly. If the output of the MG set or alternate power supply exceeds 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

The 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 components that receive power from the RPS buses, by acting to disconnect the RPS from the power supply under specified conditions that could damage the RPS equipment.

RPS electric power monitoring satisfies Criterion 3 of the NRC Policy Statement.

LCO

The OPERABILITY of each RPS electric power monitoring assembly is dependent on 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. 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 components. Each inservice electric power monitoring assembly's trip logic setpoints are required to be within the specified Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each RPS electric power monitoring assembly trip logic (refer to SR 3.3.8.2.2). Trip setpoints are specified in design documents. The trip setpoints are selected based on engineering judgement and operational experience to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setting less conservative than the trip setpoint, but within its Allowable Value, is

(continued)

BASES

LCO (continued)

acceptable. A channel is inoperable if its actual trip setting 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 changes state.

The overvoltage Allowable Values for the RPS electrical power monitoring assembly trip logic are derived from vendor specified voltage requirements.

The underfrequency Allowable Values for the RPS electrical power monitoring assembly trip logic are based on tests performed at Peach Bottom which concluded that the lowest frequency which would be reached was 54.4 Hz in 7.5 to 11.0 seconds depending load. Bench tests were also performed on RPS components (HFA relays, scram contactors, and scram solenoid valves) under conditions more severe than those expected in the plant (53 Hz during 11.0 and 15.0 second intervals). Examination of these components concluded that the components functioned correctly under these conditions.

The undervoltage Allowable Values for the RPS electrical power monitoring assembly trip logic were confirmed to be acceptable through testing. Testing has shown the scram pilot solenoid valves can be subjected to voltages below 95 volts with no degradation in their ability to perform their safety function. It was concluded the RPS logic relays and scram contactors will not be adversely affected by voltage below 95 volts since these components will dropout under these voltage conditions thereby satisfying their safety function.

APPLICABILITY

The operation of the RPS electric power monitoring assemblies is essential to disconnect the RPS 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 components are required to be OPERABLE. This results in the RPS Electric Power Monitoring System OPERABILITY being required in MODES 1 and 2; and in MODES 3, 4, and 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.

(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 components under degraded voltage or frequency conditions. However, the reliability and redundancy of the RPS Electric Power Monitoring System is reduced, and only a limited time (72 hours) is allowed to restore the inoperable assembly to OPERABLE status. If the inoperable assembly cannot be restored to OPERABLE status, the associated power supply(s) must be removed from service (Required Action A.1). This places the RPS bus in a safe condition. An alternate power supply with OPERABLE powering 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.

Alternately, if it is not desired to remove the power supply 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 supply(s) must be removed from service within 1 hour (Required Action B.1). An alternate power supply with OPERABLE assemblies may then be used to power one RPS bus.

(continued)

BASES

ACTIONS

B.1 (continued)

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 or 2, 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. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 3, 4, or 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 D.1 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.1

A CHANNEL FUNCTIONAL TEST is performed on each overvoltage, undervoltage, and underfrequency channel to ensure that the entire channel will perform the intended function. Any setpoint adjustment shall be consistent with design documents.

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). As such, this Surveillance is required to be performed when the unit is in MODE 4 for ≥ 24 hours and the test has not been performed in the previous 184 days. This Surveillance must be performed prior to entering MODE 2 or 3 from MODE 4 if a performance is required. The 24 hours is intended to indicate an outage of sufficient duration to allow for scheduling and proper performance of the Surveillance.

The 184 day Frequency and the Note in the Surveillance are based on guidance provided in Generic Letter 91-09 (Ref. 2).

SR 3.3.8.2.2 and SR 3.3.8.2.3

CHANNEL CALIBRATION is a complete check of the relay circuitry and applicable time delay relays. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted between successive calibrations consistent with the plant design documents.

The Frequency is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.8.2.4

Performance of a system functional test demonstrates that, with a required system actuation (simulated or actual) signal, the logic of the system will automatically trip open the associated power monitoring assembly. Only one signal

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.4 (continued)

per power monitoring assembly is required to be tested. This Surveillance overlaps with the CHANNEL CALIBRATION to provide complete testing of the safety function. The system functional test of the Class 1E circuit breakers is included as part of this test to provide complete testing of the safety function. If the breakers are incapable of operating, the associated electric power monitoring assembly would be inoperable.

The 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 will pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. UFSAR, Section 7.2.3.2.
2. NRC Generic Letter 91-09, "Modification of Surveillance Interval for the Electrical Protective Assemblies in Power Supplies for the Reactor Protection System."

TABLE OF CONTENTS

A

B

(continued)

B

(continued)

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BASES

LCO (continued)

in operation, modifications to the required APLHGR limits (power- and flow-dependent APLHGR multipliers, $MAPFAC_P$ and $MAPFAC_f$, respectively of LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"), MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and APRM Flow Biased High Scram Allowable Value (LCO 3.3.1.1) must be applied to allow continued operation consistent with the assumptions of References 5 and 6.

The LCO is modified by a Note which allows up to 12 hours before having to put in effect the required modifications to required limits after a change in the reactor operating conditions from two recirculation loops operating to single recirculation loop operation. If the required limits are not in compliance with the applicable requirements at the end of this period, the associated equipment must be declared inoperable or the limits "not satisfied," and the ACTIONS required by nonconformance with the applicable specifications implemented. This time is provided due to the need to stabilize operation with one recirculation loop, including the procedural steps necessary to limit flow in the operating loop, limit total THERMAL POWER, monitor for excessive APRM and local power range monitor (LPRM) neutron flux noise levels; and the complexity and detail required to fully implement and confirm the required limit modifications.

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

With one or two recirculation loops in operation with core flow as a function of THERMAL POWER in the "Restricted" Region of Figure 3.4.1-1, the plant is operating in a region where the potential for thermal hydraulic instability exists. In order to assure sufficient margin is provided for operator response to detect and suppress potential limit cycle oscillations, APRM and local power range monitor

(continued)

BASES

ACTIONS

A.1 (continued)

(LPRM) neutron flux noise levels must be periodically monitored and verified to be ≤ 4% and ≤ 3 times baseline noise levels. Detector levels A and C of one LPRM string per core quadrant plus detectors A and C of one LPRM string in the center of the core shall be monitored. A minimum of four APRMs shall also be monitored. The Completion Times of this verification (within 1 hour and once per 8 hours thereafter and within 1 hour after completion of any THERMAL POWER increase ≥ 5% RATED THERMAL POWER) are acceptable for ensuring potential limit cycle oscillations are detected to allow operator response to suppress the oscillation. These Completion Times were developed considering the operator's inherent knowledge of reactor status and sensitivity to potential thermal hydraulic instabilities when operating in this condition.

B.1

With the Required Action and associated Completion Time of Condition A not met, sufficient margin may not be available for operator response to suppress potential limit cycle oscillations since APRM or LPRM neutron flux noise levels may be > 4% and > 3 times baseline noise levels. As a result, action must be immediately initiated to restore noise levels to within required limits. The 2 hour Completion Time for restoring APRM and LPRM neutron flux noise levels to within required limits is acceptable because it minimizes risk while allowing time for restoration before subjecting the plant to transients associated with shutdown.

C.1 and C.2

With one recirculation loop in operation with core flow ≤ 39% of rated core flow and THERMAL POWER in the "Restricted" Region of Figure 3.4.1-1, an increased potential for thermal hydraulic instability exists. As a result, immediate action should be initiated to reduce THERMAL POWER to the "Unrestricted" Region of Figure 3.4.1-1 or increase core flow to > 39% of rated core flow. The

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

4 hour Completion Time provides a reasonable amount of time to complete the Required Action and is considered acceptable based on the frequent core monitoring by the operators (Required Action A.1) allowing potential limit cycle oscillations to be quickly detected.

D.1

With the requirements of the LCO not met for reasons other than Conditions A, B, C, and F, the recirculation loops must be restored to operation with matched flows within 24 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. The loop with the lower flow must be considered not in operation. (However, the flow rate of both loops shall be used for the purposes of determining if the THERMAL POWER and core flow combination is in the Unrestricted Region of Figure 3.4.1-1.) 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 and RPS setpoints, operation with only one recirculation loop would satisfy the requirements of the LCO and the initial conditions of the accident sequence.

The 24 hour Completion Time is 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.

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

(continued)

BASES

ACTIONS

D.1 (continued)

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.

E.1

With any Required Action and associated Completion Time of Condition B, C, or D 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 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.

F.1

With no recirculation loops in operation, the plant must be brought to a MODE in which the LCO does not apply. Action must be initiated immediately to reduce THERMAL POWER to be within the "Unrestricted" Region of Figure 3.4.1-1 to assure thermal hydraulic stability concerns are addressed. The plant is then required to be placed in MODE 3 in 6 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 is reasonable to reach MODE 3 considering the potential for thermal hydraulic instability in this condition.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

This SR ensures the recirculation loops are within the allowable limits for mismatch. At low core flow (i.e., $< 71.75 \times 10^6$ 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1 (continued)

can therefore be allowed when core flow is < 71.75 X 10^6 lbm/hr. The recirculation loop jet pump flow, as used in this Surveillance, is the summation of the flows from all of the jet pumps associated with a single recirculation loop.

The mismatch is measured in terms of core flow. (Rated core flow is 102.5 X 10^6 lbm/hr. The first limit is based on mismatch ≤ 10% of rated core flow when operating at < 70% of rated core flow. The second limit is based on mismatch ≤ 5% of rated core flow when operating at ≥ 70% of rated core flow.) If the flow mismatch exceeds the specified limits, the loop with the lower flow is considered not in operation. (However, for the purposes of performing SR 3.4.1.2, the flow rate of both loops shall be used.) The 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 Surveillance 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 reactor THERMAL POWER and core flow are within appropriate parameter limits to prevent uncontrolled power oscillations. At low recirculation flows and high reactor power, the reactor exhibits increased susceptibility to thermal hydraulic instability. Figure 3.4.1-1 is based on guidance provided in Reference 6, which is used to respond to operation in these conditions. The 24 hour Frequency is based on operating experience and the operators' inherent knowledge of reactor status, including significant changes in THERMAL POWER and core flow.

REFERENCES

1. UFSAR, Section 14.6.3.

2. NEDC-32163P, "PBAPS Units 2 and 3 SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," January 1993.

(continued)

BASES

REFERENCES (continued)

3. NEDC-32162P, "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Peach Bottom Atomic Power Station Unit 2 and 3," Revision 1, February 1993.

4. NEDC-32428P, "Peach Bottom Atomic Power Station Unit 2 Cycle 11 ARTS Thermal Limits Analyses," December 1994.

5. NEDO-24229-1, "PBAPS Units 2 and 3 Single-Loop Operation," May 1980.

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

7. NRC Bulletin 88-07, "Power Oscillations in Boiling Water Reactors (BWRs)," Supplement 1, December 30, 1988.

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

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 Jet Pumps

BASES

BACKGROUND

The Reactor Coolant Recirculation 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 reactor vessel internals and in conjunction with the Reactor Coolant Recirculation System 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 ten 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 implicit 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.
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 Reactor Coolant Recirculation 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 Reactor Coolant Recirculation System (LCO 3.4.1). In MODES 3, 4, and 5, the Reactor Coolant Recirculation System is not required to be in operation, and when not in operation, sufficient flow is not available to evaluate jet pump OPERABILITY.
ACTIONS	<u>A.1</u> An inoperable jet pump can increase the blowdown area and reduce the capability of reflooding 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 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

This SR is designed to detect significant degradation in jet pump performance that precedes jet pump failure (Ref. 2). 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 the 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. 2 and 3). Each recirculation loop must satisfy one of the performance criteria provided. 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 baselining 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 (pump flow and 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 indicates a plug, flow restriction, loss in pump hydraulic performance, leakage, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, the pump flow and loop flow versus pump speed relationship must be verified.

Individual jet pumps in a recirculation loop normally 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1 (continued)

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. This may be indicated by an increase in the relative flow for a jet pump that has experienced beam cracks.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system (Ref. 2). Normal flow ranges and established jet pump flow and differential pressure patterns are established by plotting historical data as discussed in Reference 2.

The 24 hour Frequency has been shown by operating experience to be timely for detecting jet pump degradation and is consistent with the Surveillance 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% of 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. UFSAR, Section 14.6.3.
2. GE Service Information Letter No. 330, "Jet Pump Beam Cracks," June 9, 1980.
3. 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) and Safety Valves (SVs)

BASES

BACKGROUND

The ASME Boiler and Pressure Vessel Code 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 SRVs and SVs 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 and SVs are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. The SRVs can actuate by either of two modes: the safety mode or the depressurization mode. In the safety mode, the pilot disc opens when steam pressure at the valve inlet expands the bellows to the extent that the hydraulic seating force on the pilot disc is reduced to zero. Opening of the pilot stage allows a pressure differential to develop across the second stage disc which opens the second stage disc, thus venting the chamber over the main valve piston. This causes a pressure differential across the main valve piston which opens the main valve. The SVs are spring loaded valves that actuate when steam pressure at the inlet overcomes the spring force holding the valve disc closed. This satisfies the Code requirement.

Each of the 11 SRVs discharge steam through a discharge line to a point below the minimum water level in the suppression pool. The two SVs discharge steam directly to the drywell. In the depressurization mode, the SRV is opened by a pneumatic actuator which opens the second stage disc. The main valve then opens as described above for the safety mode. The depressurization mode provides controlled depressurization of the reactor coolant pressure boundary. All 11 of the SRVs function in the safety mode and have the capability to operate in the depressurization mode via manual actuation from the control room. Five of the SRVs are allocated to the Automatic Depressurization System (ADS). The ADS requirements are specified in LCO 3.5.1, "ECCS—Operating."

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressurization 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). For the purpose of the analyses, 11 SRVs and SVs are assumed to operate in the safety mode. The analysis results demonstrate that the design SRV and SV capacity is capable of maintaining reactor pressure below the ASME Code limit 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 Design Basis Event.

From an overpressure standpoint, the design basis events are bounded by the MSIV closure with flux scram event described above. Reference 2 discusses additional events that are expected to actuate the SRVs and SVs.

SRVs and SVs satisfy Criterion 3 of the NRC Policy Statement.

LCO

The safety function of any combination of 11 SRVs and SVs are required to be OPERABLE to satisfy the assumptions of the safety analysis (Refs. 1 and 2). Regarding the SRVs, the requirements of this LCO are applicable only to their capability to mechanically open to relieve excess pressure when the lift setpoint is exceeded (safety mode).

The SRV and SV setpoints are established to ensure that the ASME Code limit on peak reactor pressure is satisfied. The ASME Code specifications require the lowest safety valve setpoint to be at or below vessel design pressure (1250 psig) and the highest safety valve to be set so that the total accumulated pressure does not exceed 110% of the design pressure for overpressurization conditions. The transient evaluations in the UFSAR are based on these setpoints, but also include the additional uncertainties of + 1% of the nominal setpoint 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.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, all required SRVs and SVs must be OPERABLE, since considerable energy may be in the reactor core and the limiting design basis transients are assumed to occur in these MODES. The SRVs and SVs may be required to provide pressure relief to discharge energy from the core until such time that the Residual Heat Removal (RHR) System is capable of dissipating the core heat.

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 and SV function is not needed during these conditions.

ACTIONS

A.1 and A.2

With less than the minimum number of required SRVs or SVs OPERABLE, a transient may result in the violation of the ASME Code limit on reactor pressure. If the safety function of one or more required SRVs or SVs is 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 and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

This Surveillance requires that the required SRVs and SVs will open at the pressures assumed in the safety analyses of References 1 and 2. The demonstration of the SRV and SV safety lift settings must be performed during shutdown, since this is a bench test, to be done 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 and be verified with insulation installed simulating the in-plant condition. The SRV and SV setpoint is ± 1% for OPERABILITY.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 control valves or bypass valves, by a change in the measured steam flow, or by 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 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 greater than or equal to the Electro-Hydraulic Control (EHC) System minimum pressure set with EHC controlling pressure (EHC begins controlling pressure at a nominal 150 psig). Adequate steam flow is represented by at least 3 turbine bypass valves open. Plant startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME Code requirements, prior to valve installation. 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 is reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SR. If a 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 considered OPERABLE.

The 24 month Frequency is based on the need to perform the Surveillance under the conditions that apply just prior to or during a startup from a plant outage. Operating experience has shown that these components will pass the SR when performed at the 24 month Frequency, which is based on the refueling outage. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. NEDC-32183P, "Power Rerate Safety Analysis Report for Peach Bottom 2 & 3," May 1993.

2. UFSAR, Chapter 14.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 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 the UFSAR (Refs. 1, 2, and 3).

The safety significance of RCS LEAKAGE from the RCPB varies widely depending on the source, rate, and duration. Therefore, detection of LEAKAGE in the primary containment 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 that is detrimental to the safety of the facility or the public.

A limited amount of leakage inside primary containment is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected and isolated from the primary containment 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 that, 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 that leakage rates of hundreds of gallons per minute will precede crack instability.

The low limit on increase in unidentified LEAKAGE assumes a failure mechanism of intergranular stress corrosion cracking (IGSCC) in service sensitive type 304 and type 316 austenitic stainless steel 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.

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, since it is 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. <u>Unidentified LEAKAGE</u>

The 5 gpm of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and drywell sump level monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB.

c. <u>Total LEAKAGE</u>

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. <u>Unidentified LEAKAGE Increase</u>

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 service sensitive 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 piping is very susceptible to IGSCC.

The 4 hour Completion Time is reasonable to properly reduce the LEAKAGE increase or verify the source before the reactor must be shut down without unduly jeopardizing plant safety.

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

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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 safety systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

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 3.4.5, "RCS Leakage Detection Instrumentation." Sump level and flow rate are typically monitored to determine actual LEAKAGE rates; however, any method may be used to quantify LEAKAGE within the guidelines of Reference 6. In conjunction with alarms and other administrative controls, a 4 hour Frequency for this Surveillance is appropriate for identifying LEAKAGE and for tracking required trends (Ref. 7).

REFERENCES

1. 10 CFR 50.2.
2. 10 CFR 50.55a(c).
3. UFSAR, Section 4.10.4.
4. GEAP-5620, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flaws," April 1968.
5. NUREG-75/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactors," October 1975.
6. Regulatory Guide 1.45, May 1973.
7. Generic Letter 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping," January 1988.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

UFSAR Safety Design Basis (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 leakage rates. The Bases for LCO 3.4.4, "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 level changes and drywell gaseous radioactivity levels. The primary means of quantifying LEAKAGE in the drywell is the drywell floor drain sump monitoring system.

The drywell floor drain sump 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.

An alternate to the drywell floor drain sump monitoring system is the drywell equipment drain sump monitoring system, but only if the drywell floor drain sump is overflowing. The drywell equipment drain sump collects not only all leakage not collected in the drywell floor drain sump, but also any overflow from the drywell floor drain sump. Therefore, if the drywell floor drain sump is

(continued)

BASES

BACKGROUND (continued)

overflowing to the drywell equipment drain sump, the drywell equipment drain sump monitoring system can be used to quantify LEAKAGE. In this condition, all LEAKAGE measured by the drywell equipment drain sump monitoring system is assumed to be unidentified LEAKAGE.

The floor drain sump level indicators have switches that start and stop the sump pumps when required. If the sump fills to the high high level setpoint, an alarm sounds in the control room, indicating a LEAKAGE rate into the sump in excess of 50 gpm.

A flow transmitter in the discharge line of the drywell floor drain sump pumps provides flow indication in the control room. The pumps can also be started from the control room.

The primary containment air monitoring system continuously monitors the primary containment atmosphere for airborne 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 primary containment atmosphere gaseous radioactivity monitoring system is not capable of quantifying LEAKAGE rates, but is sensitive enough to indicate increased LEAKAGE rates of 1 gpm within 1 hour. Larger changes in LEAKAGE rates are detected in proportionally shorter times (Ref. 3).

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. 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.

(continued)

BASES (continued)

LCO

The drywell sump monitoring system is required to quantify the unidentified LEAKAGE from the RCS. Thus, for the system to be considered OPERABLE, the system must be capable of measuring reactor coolant leakage. This may be accomplished by use of the associated drywell sump flow integrator, flow recorder, or the pump curves and drywell sump pump out time. The system consists of a) the drywell floor drain sump monitoring system, or b) the drywell equipment drain sump monitoring system, but only when the drywell floor drain sump is overflowing. The other monitoring system provides 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 3.4.4. This Applicability is consistent with that for LCO 3.4.4.

ACTIONS

A.1

With the drywell sump monitoring system inoperable, no other form of sampling can provide the equivalent information to quantify leakage. However, the primary containment atmospheric radioactivity monitor will provide indication of changes in leakage.

With the drywell sump monitoring system inoperable, operation may continue for 24 hours. The 24 hour Completion Time is acceptable, based on operating experience, considering no other method to quantify leakage is available.

B.1 and B.2

With the gaseous primary containment atmospheric monitoring channel inoperable, grab samples of the primary containment atmosphere must be taken and analyzed for gaseous radioactivity to provide periodic leakage information. Provided a sample is obtained and analyzed once every 12 hours, the plant may be operated for up to 30 days to allow restoration of the required monitor.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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 the gaseous primary containment atmospheric monitoring channel is inoperable. This allowance is provided because other instrumentation is available to monitor RCS leakage.

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 MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to perform the actions 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

SR 3.4.5.1

This SR is for the performance of a CHANNEL CHECK of the required primary containment 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 3.4.5.2

This SR is for 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 3.4.5.3

This SR is for the performance of a CHANNEL CALIBRATION of required leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string.

The Frequency is 92 days and operating experience has proven this Frequency is acceptable.

REFERENCES

1. UFSAR, Section 4.10.2.
2. Regulatory Guide 1.45, May 1973.
3. UFSAR, Section 4.10.3.
4. GEAP-5620, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flaws," April 1968.
5. NUREG-75/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactors," October 1975.
6. UFSAR, Section 4.10.4.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Specific Activity

BASES

BACKGROUND

During circulation, the reactor coolant acquires radioactive materials due to release of fission products from fuel leaks into the reactor coolant and activation of corrosion products in the reactor coolant. These radioactive materials in the reactor 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 that 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 the 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 level is intended to limit the 2 hour radiation dose to an individual at the site boundary to well within the 10 CFR 100 limit.

APPLICABLE SAFETY ANALYSES

Analytical methods and assumptions involving radioactive material in the primary coolant are presented in the UFSAR (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 the dose guidelines of 10 CFR 100.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The limits on specific activity are values from a parametric evaluation of typical site locations. These limits are 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.
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 well within 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	<u>A.1 and A.2</u> 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) to be cleaned up with the normal processing systems.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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 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 $\leq$ 0.2 μCi/gm within 48 hours, or if at any time it is > 4.0 μCi/gm, it must be determined at least once 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.

Alternatively, the plant can be placed in MODE 3 within 12 hours and in 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 placing the unit in MODES 3 and 4 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS	SR 3.4.6.1 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. 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, 1973. 2. UFSAR, Section 14.6.5.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 Residual Heat Removal (RHR) Shutdown Cooling System—Hot 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 reduce the temperature of the reactor coolant to ≤ 212°F. This decay heat removal is in preparation for performing refueling or maintenance operations, or for keeping the reactor in the Hot Shutdown condition.

The RHR System has two loops with each loop consisting of two motor driven pumps, two heat exchangers, and associated piping and valves. There are two RHR shutdown cooling subsystems per RHR System loop. Both loops have a common suction from the same recirculation loop. The four redundant, manually controlled shutdown cooling subsystems of the RHR System provide decay heat removal. 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 High Pressure Service Water (HPSW) System. Any one of the four RHR shutdown cooling subsystems can provide the required decay heat removal function.

APPLICABLE SAFETY ANALYSES

Decay heat removal by operation of 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.

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, a HPSW pump capable of providing cooling to the heat exchanger, and the associated piping and valves. The two subsystems have a common suction source and are allowed to have common discharge piping. Since piping is a passive component that

(continued)

BASES

LCO (continued)

is assumed not to fail, it is allowed to be common to both subsystems. 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 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 required 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 required 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 shutdown cooling isolation pressure (i.e., the actual pressure at which the RHR shutdown cooling isolation pressure setpoint clears) 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 shutdown cooling isolation 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 shutdown cooling isolation pressure is typically accomplished by condensing the steam in the main condenser.

(continued)

BASES

APPLICABILITY (continued)

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 3.4.8, "Residual Heat Removal (RHR) Shutdown Cooling System—Cold Shutdown"; LCO 3.9.7, "Residual Heat Removal (RHR)—High Water Level"; and LCO 3.9.8, "Residual Heat Removal (RHR)—Low Water Level."

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 required 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

(continued)

BASES

ACTIONS

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

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 required RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities.

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

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 permitted by LCO Note 1, reactor coolant circulation by the RHR shutdown cooling subsystem or 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

(continued)

BASES

ACTIONS

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

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 3.4.7.1

This Surveillance verifies that one required 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 setpoint 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

None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 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 ≤ 212°F. This decay heat removal is in preparation for performing refueling or maintenance operations, or for keeping the reactor in the Cold Shutdown condition.

The RHR System has two loops with each loop consisting of two motor driven pumps, two heat exchangers, and associated piping and valves. There are two RHR shutdown cooling subsystems per RHR System loop. Both loops have a common suction from the same recirculation loop. The four redundant, manually controlled shutdown cooling subsystems of the RHR System provide decay heat removal. 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 High Pressure Service Water (HPSW) System. Any one of the four RHR shutdown cooling subsystems can provide the requested decay heat removal function.

APPLICABLE SAFETY ANALYSES

Decay heat removal by operation of 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.

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, a HPSW pump capable of providing cooling to the heat exchanger, and the associated piping and valves. The two subsystems have a common suction source and are allowed to have common discharge piping. Since piping is a passive component that is assumed not to fail, it is allowed to be common to both

(continued)

BASES

LCO (continued)

both subsystems. In MODE 4, the RHR cross tie valve (MO-2-10-020) may be opened (per LCO 3.5.2) to allow pumps in one loop to discharge through the opposite recirculation loop to make a complete subsystem. In addition, the HPSW cross-tie valve may be opened to allow an HPSW pump in one loop to provide cooling to a heat exchanger in the opposite loop to make a complete subsystem. Additionally, 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 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 required RHR shutdown cooling subsystems to be shut down for a period of 2 hours in an 8 hour period. Note 2 allows one required 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 212°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 shutdown cooling isolation 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 above the RHR shutdown cooling isolation pressure is typically accomplished by condensing the steam in the main condenser.

(continued)

BASES

APPLICABILITY (continued)

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 RHR shutdown cooling isolation pressure and in MODE 5 are discussed in LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown"; LCO 3.9.7, "Residual Heat Removal (RHR)—High Water Level"; and LCO 3.9.8, "Residual Heat Removal (RHR)—Low Water Level."

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 required 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 required 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

(continued)

BASES

ACTIONS

A.1 (continued)

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 Condensate/Main Steam Systems (feed and bleed) and the Reactor Water Cleanup System.

B.1 and B.2

With no RHR shutdown cooling subsystem and no recirculation pump in operation, except as 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS	SR 3.4.8.1 This Surveillance verifies that one required 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	None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 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, and inservice leakage and hydrostatic testing, and also limits the maximum rate of change of reactor coolant temperature. The criticality curve provides limits for both heatup and criticality.

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 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, abnormal operational transients, and system hydrostatic tests. It mandates the use of the 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 with the UFSAR (Ref. 3) and Appendix H of 10 CFR 50 (Ref. 4). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of Reference 5.

(continued)

BASES

BACKGROUND (continued)

The P/T limit curves are composite curves established by superimposing limits derived from stress 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.

The 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 60°F above the adjusted reference temperature of the reactor vessel material in the region that is controlling (reactor vessel flange region).

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the reactor pressure vessel, 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. 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 reactor pressure vessel, a condition that is unanalyzed. References 7 and 8 approved the curves and limits specified in this section. 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.

B

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

RCS P/T limits satisfy Criterion 2 of the NRC Policy Statement.

LCO

The elements of this LCO are:

a. RCS pressure and temperature are within the limits specified in Figures 3.4.9-1 and 3.4.9-2, and heatup or cooldown rates are ≤ 100°F during RCS heatup, cooldown, and inservice leak and hydrostatic testing;

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;

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;

d. RCS pressure and temperature are within the criticality limits specified in Figure 3.4.9-3, prior to achieving criticality; and

e. The reactor vessel flange and the head flange temperatures are > 70°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.

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 leakage 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.

(continued)

BASES

LCO (continued)

Violation of the limits places the reactor vessel outside of the bounds of the stress 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 existences, sizes, and orientations 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 MODES 1, 2, and 3 must be corrected so that the RCPB is returned to a condition that has been verified by stress 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 and must be completed if continued operation is desired. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, 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.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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 placed in 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 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.

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 stress analyses. The Required Action must be initiated without delay and continued until the limits are restored.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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 > 212°F. 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 beltline.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

Verification that operation is within limits is required every 30 minutes when RCS pressure and temperature conditions are undergoing planned changes. Plant procedures specify the pressure and temperature monitoring points to be used during the performance of this Surveillance. 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 a reasonable time for assessment and correction of minor deviations.

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.

This SR has been modified with a Note that requires this Surveillance to be performed only during system heatup and cooldown operations and inservice leakage and hydrostatic testing.

SR 3.4.9.2

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.9.2 (continued)

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 3.4.9.3 and SR 3.4.9.4

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. 9) 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 3.4.9.4 is to compare the temperatures of the operating recirculation loop and the idle loop.

SR 3.4.9.3 and SR 3.4.9.4 have been modified by a Note that requires the Surveillance to be met only in MODES 1, 2, 3, and 4. In MODE 5, the overall stress on limiting components is lower. Therefore, ΔT limits are not required. The Note also states the SR is only required to be met during a recirculation pump startup, since this is when the stresses occur.

SR 3.4.9.5, SR 3.4.9.6, and SR 3.4.9.7

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 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.9.5, SR 3.4.9.6, and SR 3.4.9.7 (continued)

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 ≤ 80°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 temperature is within the limits specified.

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 3.4.9.5 is modified by a Note that requires the Surveillance to be performed only when tensioning the reactor vessel head bolting studs. SR 3.4.9.6 is modified by a Note that requires the Surveillance to be initiated 30 minutes after RCS temperature ≤ 80°F in MODE 4. SR 3.4.9.7 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 limits specified.

REFERENCES

1. 10 CFR 50, Appendix G.
2. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.
3. UFSAR, Section 4.2.6 and Appendix K.
4. 10 CFR 50, Appendix H.
5. Regulatory Guide 1.99, Revision 2, May 1988.

(continued)

BASES

REFERENCES (continued)

6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

7. R.E. Martin (NRC) letter to G.A. Hunger (PECo), Amendment No. 153 to Facility Operating License No. DPR-44 for the Peach Bottom Atomic Power Station Unit No. 2, dated October 25, 1989.

8. R.J. Clark (NRC) letter to G.J. Beck (PECo), Amendment Nos. 162 and 164 to Facility Operating License Nos. DPR-44 and DPR-56 for the Peach Bottom Atomic Power Station Units Nos. 2 and 3, dated June 27, 1991.

9. UFSAR, Section 14.5.6.2.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 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 and transients.
APPLICABLE SAFETY ANALYSES	The reactor steam dome pressure of ≤ 1053 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 along with Reference 1 assumes an initial reactor steam dome pressure for the analysis of design basis accidents 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% cladding plastic strain (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"). Reactor steam dome pressure satisfies the requirements of Criterion 2 of the NRC Policy Statement.
LCO	The specified reactor steam dome pressure limit of ≤ 1053 psig ensures the plant is operated within the assumptions of the reactor overpressure protection analysis. Operation above the limit may result in a transient response more severe than analyzed.
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 the events which may challenge the overpressure limits are possible.

(continued)

BASES

APPLICABILITY (continued)	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 occurring while pressure is greater than the limit is minimized. 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 3.4.10.1 Verification that reactor steam dome pressure is ≤ 1053 psig ensures that the initial conditions of the reactor overpressure protection analysis and design basis accidents are met. Operating experience has shown the 12 hour Frequency to be sufficient for identifying trends and verifying operation within safety analyses assumptions.
REFERENCES	1. Letter G94-PEPR-002A, Peach Bottom Rerate Project Overpressure Analysis at LCO Dome Pressure, from G.V. Kumar (GE) to T.E. Shannon (PECo), January 18, 1994. 2. UFSAR, Chap‑‑r 14.

BASES

BACKGROUND (continued)

ineffective; however,the overall design is effective in cooling the core regardless of the size or location of the piping break.

All ECCS subsystems are designed to ensure that no single active component failure will prevent automatic initiation and successful operation of the minimum required ECCS equipment.

The CS System (Ref. 1) is composed of two independent subsystems. Each subsystem consists of two 50% capacity motor driven pumps, a spray sparger above the core, and piping and valves to transfer water from the suppression pool to the sparger. The CS System is designed to provide cooling to the reactor core when reactor pressure is low. Upon receipt of an initiation signal, the CS pumps in both subsystems are automatically started (if offsite power is available, A and C pumps in approximately 13 seconds, and B and D pumps in approximately 23 seconds, and if offsite power is not available, all pumps 6 seconds after AC power is available). When the RPV pressure drops sufficiently, CS System flow to the RPV begins. A full flow test line is provided to route water from and to the suppression pool to allow testing of the CS System without spraying water in the RPV.

LPCI is an independent operating mode of the RHR System. There are two LPCI subsystems (Ref. 2), each consisting of two motor driven pumps and piping and valves to transfer water from the suppression pool to the RPV via the corresponding recirculation loop. The two LPCI pumps and associated motor operated valves in each LPCI subsystem are powered from separate 4 kV emergency buses. Both pumps in a LPCI subsystem inject water into the reactor vessel through a common inboard injection valve and depend on the closure of the recirculation pump discharge valve following a LPCI injection signal. Therefore, each LPCI subsystems' common inboard injection valve and recirculation pump discharge valve is powered from one of the two 4 kV emergency buses associated with that subsystem (normal source) and has the capability for automatic transfer to the second 4 kV emergency bus associated with that LPCI subsystem. The ability to provide power to the inboard injection valve and the recirculation pump discharge valve from either 4 kV emergency bus associated with the LPCI subsystem ensures that the single failure of a diesel generator (DG) will not result in the failure of both LPCI pumps in one subsystem.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

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

C.1 and C.2

If the HPCI System is inoperable and the RCIC System is immediately verified to be OPERABLE, the HPCI 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 ADS. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Immediate verification of RCIC OPERABILITY is therefore required when HPCI is inoperable. This may be performed as an administrative check by examining logs or other information to determine if RCIC is out of service for maintenance or other reasons. It does not mean to perform the Surveillances needed to demonstrate the OPERABILITY of the RCIC System. If the OPERABILITY of the RCIC System cannot be verified immediately, however, Condition E 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 a reliability study cited in Reference 9 and has been found to be acceptable through operating experience.

D.1 and D.2

If any one low pressure ECCS injection/spray subsystem is inoperable in addition to an inoperable HPCI System, the inoperable low pressure ECCS injection/spray subsystem or the HPCI System must be restored to OPERABLE status within 72 hours. In this Condition, adequate core cooling is

(continued)

BASES

LCO (continued)

One LPCI subsystem may be aligned for decay heat removal and considered OPERABLE for the ECCS function, if it can be manually realigned (remote or local) to the LPCI mode and is not otherwise inoperable. 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 low pressure 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, the water level maintained at ≥ 458 inches above reactor pressure vessel instrument zero (20 ft 11 inches above the RPV flange), and no operations with a potential for draining the reactor vessel (OPDRVs) in progress. 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 ≤ 100 psig, and the CS System and the LPCI subsystems can provide core cooling without any depressurization of the primary system.

The High Pressure Coolant Injection System is not required to be OPERABLE during MODES 4 and 5 since the low pressure ECCS injection/spray subsystems can provide sufficient flow to the vessel.

ACTIONS

A.1 and B.1

If any one required low pressure ECCS injection/spray subsystem is inoperable, an inoperable subsystem must be restored to OPERABLE status in 4 hours. In this Condition, the remaining OPERABLE subsystem can provide sufficient vessel flooding capability to recover from an inadvertent vessel draindown. However, overall system reliability is reduced because a single failure in the remaining OPERABLE

(continued)

BASES

ACTIONS

A.1 and B.1 (continued)

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 low pressure ECCS injection/spray subsystem to OPERABLE status is based on engineering judgment that considered the remaining available subsystem and the low probability of a vessel draindown event.

With the inoperable subsystem not restored to OPERABLE status in the required Completion Time, action must be immediately initiated to suspend 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

With both of the required ECCS injection/spray subsystems inoperable, all coolant inventory makeup capability may be unavailable. Therefore, actions must immediately be initiated to suspend OPDRVs 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.

If at least one low pressure 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 for Unit 2 is OPERABLE; and secondary containment isolation capability (i.e., one isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability) in each associated secondary containment penetration flow path not isolated that is assumed to be isolated to mitigate radioactivity releases. OPERABILITY may be verified by an administrative check, or by examining logs or other information, to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1 (continued)

testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall primary containment leakage rate. The Frequency is required by 10 CFR 50, Appendix J (Ref. 2), as modified by approved exemptions. Thus, SR 3.0.2 (which allows Frequency extensions) does not apply.

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

SR 3.6.1.2.2

The air lock interlock mechanism is designed to prevent simultaneous opening of both doors in the air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident primary containment pressure, closure of either door will support primary containment OPERABILITY. Thus, the interlock feature supports primary containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous inner and outer door opening will not inadvertently occur. Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is only challenged when primary containment is entered, this test is only required to be performed upon entering primary containment, but is not required more frequently than 184 days when primary containment is de-inerted. The 184 day Frequency is based on engineering judgment and is considered adequate in view of other administrative controls available to operations personnel.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 5.2.3.4.5.

2. 10 CFR 50, Appendix J.

3. Letter G94-PEPR-183, Peach Bottom Improved Technical Specification Project Increased Drywell and Suppression Chamber Pressure Analytical Limits, from G.V. Kumar (GE) to A.A. Winter (PECo), August 23, 1994.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the UFSAR, Chapter 14 (Ref. 4), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the onsite or offsite AC sources OPERABLE during accident conditions in the event of:

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

b. A worst case single failure.

AC sources satisfy Criterion 3 of the NRC Policy Statement.

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Distribution System and four separate and independent DGs ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an abnormal operational transient or a postulated DBA. In addition, since some equipment required by Unit 2 is powered from Unit 3 sources (i.e., Standby Gas Treatment (SGT) System, emergency heat sink components, and Unit 3 125 VDC battery chargers), qualified circuit(s) between the offsite transmission network and the Unit 3 onsite Class 1E AC electrical power distribution subsystem(s) needed to support this equipment must also be OPERABLE.

An OPERABLE qualified Unit 2 offsite circuit consists of the incoming breaker and disconnect to the startup and emergency auxiliary transformer, the respective circuit path to the emergency auxiliary transformer, and the circuit path to at least three Unit 2 4 kV emergency buses including feeder

(continued)

BASES

LCO (continued)

breakers to the three Unit 2 4 kV emergency buses. If at least one of the two circuits does not provide power or is not capable of providing power to all four Unit 2 4 kV emergency buses, then the Unit 2 4 kV emergency buses that each circuit powers or is capable of powering cannot all be the same (i.e., two feeder breakers on one Unit 2 4 kV emergency bus cannot be inoperable). An OPERABLE qualified Unit 3 offsite circuit's requirements are the same as the Unit 2 circuit's requirements, except that the circuit path, including the feeder breakers, is to the Unit 3 4 kV emergency buses required to be OPERABLE by LCO 3.8.7, "Distribution Systems—Operating." Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the emergency buses.

B

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective Unit 2 4 kV emergency bus on detection of bus undervoltage. This sequence must be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the emergency buses. These capabilities are required to be met from a variety of initial conditions, such as DG in standby with the engine hot and DG in standby with the engine at ambient condition. Additional DG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode. Proper sequencing of loads, including tripping of all loads, is a required function for DG OPERABILITY.

In addition, since some equipment required by Unit 2 is powered from Unit 3 sources, the DG(s) capable of supplying the Unit 3 onsite Class 1E AC electrical power distribution subsystem(s) needed to support this equipment must be OPERABLE. The OPERABILITY requirements for these DGs are the same as described above, except that each required DG must be capable of connecting to its respective Unit 3 4 kV emergency bus. (In addition, the Unit 3 ECCS initiation logic SRs are not applicable, as described in SR 3.8.1.21 Bases.)

The AC sources must be separate and independent (to the extent possible) of other AC sources. For the DGs, the separation and independence are complete. For the offsite

(continued)

BASES

LCO (continued)

AC sources, the separation and independence are to the extent practical. A circuit may be connected to more than one 4 kV emergency bus division, with automatic transfer capability to the other circuit OPERABLE, and not violate separation criteria. A circuit that is not connected to at least three 4 kV emergency buses is required to have OPERABLE automatic transfer interlock mechanisms such that it can provide power to at least three 4 kV emergency buses to support OPERABILITY of that circuit.

APPLICABILITY

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

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

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

The AC power requirements for MODES 4 and 5 are covered in LCO 3.8.2, "AC Sources—Shutdown."

ACTIONS

A.1

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

A.2

Required Action A.2, which only applies if one 4 kV emergency bus cannot be powered from any offsite source, is intended to provide assurance that an event with a coincident single failure of the associated DG does not result in a complete loss of safety function of critical systems. These features (e.g., system, subsystem, division,

(continued)

BASES

ACTIONS

A.2 (continued)

component, or device) are designed to be powered from redundant safety related 4 kV emergency buses. Redundant required features failures consist of inoperable features associated with an emergency bus redundant to the emergency bus that has no offsite power.

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

a. A 4 kV emergency bus has no offsite power supplying its loads; and

b. A redundant required feature on another 4 kV emergency bus is inoperable.

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

Discovering no offsite power to one 4 kV emergency bus of the onsite Class 1E Power Distribution System coincident with one or more inoperable required support or supported features, or both, that are associated with any other emergency bus that has offsite power, results in starting the Completion Times for the Required Action. Twenty-four hours is acceptable because it minimizes risk while allowing time for restoration before the unit is subjected to transients associated with shutdown.

The remaining OPERABLE offsite circuits and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection may have been lost for the required feature's function; however, function is not lost. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

A.3

The 4 kV emergency bus design and loading is sufficient to allow operation to continue in Condition A for a period not to exceed 7 days. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the plant safety systems. In this condition, however, the remaining OPERABLE offsite circuits and the four DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

The 7 day Completion Time takes into account the redundancy, capacity, and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.1.a or b. If Condition A is entered while, for instance, a DG is inoperable, and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 7 days. This situation could lead to a total of 14 days, since initial failure to meet LCO 3.8.1.a or b, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 7 days (for a total of 21 days) allowed prior to complete restoration of the LCO. The 14 day Completion Time provides a limit on the time allowed in a specified Condition after discovery of failure to meet LCO 3.8.1.a or b. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 7 day and 14 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time that Condition A was entered.

(continued)

BASES

ACTIONS (continued)

B.4.2.1 and B.4.2.2

The 33 kV Conowingo Tie-Line using a separate 33/13.8 kV transformer, can be used to supply the circuit normally supplied by startup and emergency auxiliary transformer no. 2. While not a qualified circuit, this alternate source is a direct tie to the Conowingo Hydro Station that provides a highly reliable source of power because: the line and transformers at both ends of the line are dedicated to the support of PBAPS; the tie line is not subject to damage from adverse weather conditions; and, the tie line can be isolated from other parts of the grid when necessary to ensure its availability and stability to support PBAPS. The availability of this highly reliable source of offsite power permits an extension to the 7 day allowable out of service time for a DG. Therefore, prior to the time period that the normal 7 day allowable out of service time for a DG is exceeded, it is necessary to verify the availability of the Conowingo Tie-Line. The Conowingo Tie-Line is available and satisfies the requirements of Required Action B.4.2.1 if: 1) the tie-line is supplying power to PBAPS Unit 1; 2) manual breaker operation is available to tie power from the Unit 1/Conowingo Tie-Line to the startup and emergency auxiliary transformer no. 2; and 3) communications with the Conowingo control room is available to ensure that required equipment at Conowingo is available. The Completion Time for the restoration of the DG to OPERABLE status may not be extended beyond 7 days from the initial time that Condition B was entered (the time allowed by Required Action B.4.1) if Required Action B.4.2.1 is not satisfied within 7 days. If the status of the Conowingo Tie-Line changes after Required Action B.4.2.1 is initially met, such that the DG restoration time is now 7 days (per Required Action B.4.1), the 7 days begins upon discovery of failure to meet Required Action B.4.2.1. However, the total time to restore an inoperable DG cannot exceed 14 days (per the second Completion Time of Required Action B.4.1).

The availability of the Conowingo Tie-Line provides an additional source which permits operation to continue in Condition B for a period that should not exceed 30 days. In Condition B, the remaining OPERABLE DGs and the normal offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 30 day Completion Time takes into account the enhanced reliability

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

According to Regulatory Guide 1.93 (Ref. 6), with the available offsite AC sources two less than required by the LCO, operation may continue for 24 hours. If all offsite sources are restored within 24 hours, unrestricted operation may continue. If all but one offsite source is restored within 24 hours, power operation continues in accordance with Condition A.

D.1 and D.2

Pursuant to LCO 3.0.6, the Distribution Systems—Operating ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no AC source to any 4 kV emergency bus, ACTIONS for LCO 3.8.7, "Distribution Systems—Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of the offsite circuit and one DG without regard to whether a 4 kV emergency bus is de-energized. LCO 3.8.7 provides the appropriate restrictions for a de-energized 4 kV emergency bus.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition D for a period that should not exceed 12 hours. In Condition D, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition C (loss of two or more offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source and that appropriate independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

SR 3.8.1.2 and SR 3.8.1.7

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

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs have been modified by a Note (Note 2 for SR 3.8.1.2 and Note 1 for SR 3.8.1.7) to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period and followed by a warmup prior to loading.

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

In order to reduce stress and wear on diesel engines, the manufacturer recommends a modified start in which the starting speed of DGs is limited, warmup is limited to this lower speed, and the DGs are gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 3 to SR 3.8.1.2, which is only applicable when such modified start procedures are recommended by the manufacturer.

SR 3.8.1.7 requires that, at a 184 day Frequency, the DG starts from standby conditions and achieves required voltage and frequency within 10 seconds. The minimum voltage and frequency stated in the SR are those necessary to ensure the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

DG can accept DBA loading while maintaining acceptable voltage and frequency levels. Stable operation at the nominal voltage and frequency values is also essential to establishing DG OPERABILITY, but a time constraint is not imposed. This is because a typical DG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not damped out by load application. This period may extend beyond the 10 second acceptance criteria and could be a cause for failing the SR. In lieu of a time constraint in the SR, PBAPS will monitor and trend the actual time to reach steady state operation as a means of ensuring there is no voltage regulator or governor degradation which could cause a DG to become inoperable. The 10 second start requirement supports the assumptions in the design basis LOCA analysis of UFSAR, Section 8.5 (Ref. 10). The 10 second start requirement is not applicable to SR 3.8.1.2 (see Note 3 of SR 3.8.1.2), when a modified start procedure as described above is used. If a modified start is not used, the 10 second start requirement of SR 3.8.1.7 applies.

Since SR 3.8.1.7 requires a 10 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This procedure is the intent of Note 1 of SR 3.8.1.2.

To minimize testing of the DGs, Note 4 to SR 3.8.1.2 and Note 2 to SR 3.8.1.7 allow a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit. If the DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

The normal 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 3). The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 5). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing and accepting a load approximately equivalent to that corresponding to the continuous rating. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

This Surveillance verifies, indirectly, that the DGs are capable of synchronizing and accepting loads equivalent to post accident loads. The DGs are tested at a load approximately equivalent to their continuous duty rating, even though the post accident loads exceed the continuous rating. This is acceptable because regular surveillance testing at post accident loads is injurious to the DG, and imprudent because the same level of assurance in the ability of the DG to provide post accident loads can be developed by monitoring engine parameters during surveillance testing. The values of the testing parameters can then be qualitatively compared to expected values at post accident engine loads. In making this comparision it is necessary to consider the engine parameters as interrelated indicators of remaining DG capacity, rather than independent indicators. The important engine parameters to be considered in making this comparision include, fuel rack position, scavenging air pressure, exhaust temperature and pressure, engine output jacket water temperature, and lube oil temperature. With the DG operating at or near continuous rating and the observed values of the above parameters less than expected post accident values, a qualitative extrapolation which shows the DG is capable of accepting post accident loads can be made without requiring deterimental testing. B

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

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

Note 1 modifies this Surveillance to indicate that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized.

Note 2 modifies this Surveillance by stating that momentary transients because of changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the limit do not invalidate the test.

Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations.

Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

To minimize testing of the DGs, Note 5 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units, with the DG synchronized to the 4 kV emergency bus of Unit 2 for one periodic test and synchronized to the 4 kV emergency bus of Unit 3 during the next periodic test. This is allowed since the main purpose of the Surveillance, to ensure DG OPERABILITY, is still being verified on the proper frequency, and each unit's breaker control circuitry, which is only being tested every second test (due to the staggering of the tests), historically have a very low failure rate. If the DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit. In addition, if the test is scheduled to be performed on Unit 3, and the Unit 3 TS allowance that provides an exception to performing the test is used (i.e., when Unit 3 is in MODE 4 or 5, or moving irradiated fuel assemblies in the secondary containment, the Note to Unit 3 SR 3.8.2.1 provides an exception to performing this test), then the test shall be performed synchronized to the Unit 2 4 kV emergency bus.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is adequate for a minimum of 1 hour of DG operation at full load. The level is expressed as an equivalent volume in gallons.

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

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are consistent with Regulatory Guide 1.137 (Ref. 9). This SR is for preventive maintenance. The presence of water does not necessarily represent a failure of this SR provided that accumulated water is removed during performance of this Surveillance.

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and automatically transfers fuel oil from its associated storage tank to its associated day tank. It is required to support continuous operation of standby power sources. This Surveillance provides assurance that

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.6 (continued)

the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

The Frequency for this SR is 31 days because the design of the fuel transfer system is such that pumps operate automatically in order to maintain an adequate volume of fuel oil in the day tanks during or following DG testing and proper operation of fuel transfer systems is an inherent part of DG OPERABILITY.

SR 3.8.1.8

Transfer of each 4 kV emergency bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The 24 month Frequency of the Surveillance is based on engineering judgment taking into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components will pass the SR when performed on the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that, during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. This Surveillance tests the applicable logic associated with Unit 2. The comparable test specified in Unit 3 Technical Specifications tests the applicable logic associated with Unit 3. Consequently, a test must be performed within the specified Frequency for each unit. As the Surveillance represents separate tests, the Note specifying the restriction for not performing the test while the unit is in MODE 1 or 2 does not have applicability to Unit 3. The Note only applies to Unit 2, thus the Unit 2 Surveillance shall not be performed with Unit 2 in MODE 1 or 2. Credit may be taken for unplanned events that satisfy this SR.

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. The largest single load for each DG is a residual heat removal pump (2000 bhp). This Surveillance may be accomplished by: 1) tripping the DG output breakers with the DG carrying greater than or equal to its associated single largest post-accident load while paralleled to offsite power, or while solely supplying the bus, or 2) tripping its associated single largest post-accident load with the DG solely supplying the bus. Currently, the second option is the method PBAPS utilizes because the first method will result in steady state operation outside the allowable voltage and frequency limits. Consistent with Regulatory Guide 1.9 (Ref. 3), the load rejection test is acceptable if the diesel speed does not exceed the nominal (synchronous) speed plus 75% of the difference between nominal speed and the overspeed trip setpoint, or 115% of nominal speed, whichever is lower.

The time, voltage, and frequency tolerances specified in this SR are derived from Regulatory Guide 1.9 (Ref. 3) recommendations for response during load sequence intervals. The 1.8 seconds specified for voltage and the 2.4 seconds specified for frequency are equal to 60% and 80%, respectively, of the 3 second load sequence interval associated with sequencing the next load following the residual heat removal (RHR) pumps during an undervoltage on the bus concurrent with a LOCA. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.9.a corresponds to the maximum frequency excursion, while SR 3.8.1.9.b and SR 3.8.1.9.c provide steady state voltage and frequency values to which the system must recover following load rejection. The 24 month Frequency takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

This SR is modified by two Notes. In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, Note 1 requires that if synchronized to offsite power, testing must be performed using a power factor ≤ 0.89. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.

To minimize testing of the DGs, Note 2 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit. If the DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.10

Consistent with Regulatory Guide 1.9 (Ref. 3), paragraph C.2.2.8, this Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide DG damage protection. While the DG is not expected to experience this transient during an event, and continue to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing must be performed using a power factor ≤ 0.89. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.

(continued)

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

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

This SR is modified by a Note. To minimize testing of the DGs, the Note allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit. If the DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.11

Consistent with Regulatory Guide 1.9 (Ref. 3), paragraph C.2.2.4, this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of all loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

The DG auto-start and energization of the associated 4 kV emergency bus time of 10 seconds is derived from requirements of the accident analysis for responding to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved.

The requirement to verify the connection and power supply of auto-connected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, Emergency Core Cooling Systems (ECCS) injection valves are not desired to be stroked open, or systems are not capable of being operated at full flow, or RHR systems performing a decay

(continued)

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

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

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs shall be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This Surveillance tests the applicable logic associated with Unit 2. The comparable test specified in the Unit 3 Technical Specifications tests the applicable logic associated with Unit 3. Consequently, a test must be performed within the specified Frequency for each unit. As the Surveillance represents separate tests, the Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 3. The Note only applies to Unit 2, thus the Unit 2 Surveillances shall not be performed with Unit 2 in MODE 1, 2, or 3. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.12

Consistent with Regulatory Guide 1.9 (Ref. 3), paragraph C.2.2.5, this Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (10 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The minimum voltage and frequency stated in the SR are those necessary to ensure the DG can accept B

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

DBA loading while maintaining acceptable voltage and frequency levels. Stable operation at the nominal voltage and frequency values is also essential to establishing DG OPERABILITY, but a time constraint is not imposed. This is because a typical DG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not damped out by load application. This period may extend beyond the 10 second acceptance criteria and could be a cause for failing the SR. In lieu of a time constraint in the SR, PBAPS will monitor and trend the actual time to reach steady state operation as a means of ensuring there is no voltage regulator or governor degradation which could cause a DG to become inoperable. The 5 minute period provides sufficient time to demonstrate stability. SR 3.8.1.12.d and SR 3.8.1.12.e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on a LOCA signal without loss of offsite power.

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

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

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

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

SR 3.8.1.13

Consistent with Regulatory Guide 1.9 (Ref. 3), paragraph C.2.2.12, this Surveillance demonstrates that DG non-critical protective functions (e.g., high jacket water temperature) are bypassed on an ECCS initiation test signal and critical protective functions (engine overspeed, generator differential overcurrent, generator ground neutral overcurrent, and manual cardox initiation) trip the DG to avert substantial damage to the DG unit. The non-critical trips are bypassed during DBAs and continue to provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

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

To minimize testing of the DGs, the Note to this SR allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit. If the DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.14

Consistent with Regulatory Guide 1.9 (Ref. 3), paragraph C.2.2.9, this Surveillance requires demonstration that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours—22 hours of which is at a load equivalent to 90% to 100% of the continuous duty rating of the DG, and 2 hours of which is at a load equivalent to 105% to 110% of the continuous duty rating of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelube and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

This Surveillance verifies, indirectly, that the DGs are capable of synchronizing and accepting loads equivalent to post accident loads. The DGs are tested at a load approximately equivalent to their continuous duty rating, even though the post accident loads exceed the continuous rating. This is acceptable because regular surveillance testing at post accident loads is injurious to the DG, and imprudent because the same level of assurance in the ability of the DG to provide post accident loads can be developed by monitoring engine parameters during surveillance testing. The values of the testing parameters can then be qualitatively compared to expected values at post accident engine loads. In making this comparision it is necessary to consider the engine parameters as interrelated indicators of remaining DG capacity, rather than independent indicators. The important engine parameters to be considered in making this comparision include, fuel rack position, scavenging air pressure, exhaust temperature and pressure, engine output, jacket water temperature, and lube oil temperature. With the DG operating at or near continuous rating and the observed values of the above parameters less than expected post accident values, a qualitative extrapolation which shows the DG is capable of accepting post accident loads can be made without requiring deterimental testing. 8

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed using a power factor ≤ 0.89. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

experience. A load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

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

This Surveillance has been modified by three Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the limit do not invalidate the test. Note 2 is provided in recognition that if the offsite electrical power distribution system voltage is high, it may not be possible to raise DG output voltage without creating an overvoltage condition on the emergency bus. Therefore, to ensure the bus voltage and supplied loads, and DG are not placed in an unsafe condition during this test, the power factor limit does not have to be met if grid voltage or emergency bus loading does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the power factor should be maintained as close to the limit as practicable. To minimize testing of the DGs, Note 3 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit. If the DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 10 seconds. The minimum voltage and frequency stated in the SR are those necessary to ensure the DG can accept DBA loading while maintaining acceptable voltage and frequency levels. Stable operation at the nominal voltage and frequency values is also essential to establishing DG OPERABILITY, but a time constraint is not imposed. This is because a typical DG will experience a

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.15 (continued)

period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not damped out by load application. This period may extend beyond the 10 second acceptance criteria and could be a cause for failing the SR. In lieu of a time constraint in the SR, PBAPS will monitor and trend the actual time to reach steady state operation as a means of ensuring there is no voltage regulator or governor degradation which could cause a DG to become inoperable. The 10 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The 24 month Frequency takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by three Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The requirement that the diesel has operated for at least 2 hours at full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing. To minimize testing of the DGs, Note 3 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit. If the DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.16

Consistent with Regulatory Guide 1.9 (Ref. 3), paragraph C.2.2.11, this Surveillance ensures that the manual synchronization and load transfer from the DG to the offsite source can be made and that the DG can be returned

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.16 (continued)

to ready-to-load status when offsite power is restored. It also ensures that the auto-start logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready-to-load status when the DG is at rated speed and voltage, the output breaker is open and can receive an auto-close signal on bus undervoltage, and individual load timers are reset.

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

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This Surveillance tests the applicable logic associated with Unit 2. The comparable test specified in the Unit 3 Technical Specifications tests the applicable logic associated with Unit 3. Consequently, a test must be performed within the specified Frequency for each unit. As the Surveillance represents separate tests, the Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 3. The Note only applies to Unit 2, thus the Unit 2 Surveillances shall not be performed with Unit 2 in MODE 1, 2, or 3. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.17

Consistent with Regulatory Guide 1.9 (Ref 3), paragraph C.2.2.13, demonstration of the test mode override ensures that the DG availability under accident conditions is not compromised as the result of testing. Interlocks to the LOCA sensing circuits cause the DG to automatically reset to ready-to-load operation if a Unit 2 ECCS initiation signal is received during operation in the test mode while synchronized to either Unit 2 or a Unit 3 4 kV emergency bus. Ready-to-load operation is defined as the DG running at rated speed and voltage with the DG output breaker open.

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

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

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

To minimize testing of the DGs, the Note allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit. If the DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.18

Under accident and loss of offsite power conditions, loads are sequentially connected to the bus by individual load timers. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor starting currents. The 10% load sequence time interval tolerance ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 10 provides a summary of the automatic loading of emergency buses.

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

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.18 (continued)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This Surveillance tests the applicable logic associated with Unit 2. The comparable test specified in the Unit 3 Technical Specifications tests the applicable logic associated with Unit 3. Consequently, a test must be performed within the specified Frequency for each unit. As the Surveillance represents separate tests, the Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 3. The Note only applies to Unit 2, thus the Unit 2 Surveillances shall not be performed with Unit 2 in MODE 1, 2, or 3. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.19

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

This Surveillance demonstrates DG operation, as discussed in the Bases for SR 3.8.1.11, during a loss of offsite power actuation test signal in conjunction with an ECCS initiation signal. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

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

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.19 (continued)

consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This Surveillance tests the applicable logic associated with Unit 2. The comparable test specified in the Unit 3 Technical Specifications tests the applicable logic associated with Unit 3. Consequently, a test must be performed within the specified Frequency for each unit. As the Surveillance represents separate tests, the Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 3. The Note only applies to Unit 2, thus the Unit 2 Surveillances shall not be performed with Unit 2 in MODE 1, 2, or 3. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.20

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

The minimum voltage and frequency stated in the SR are those necessary to ensure the DG can accept DBA loading while maintaining acceptable voltage and frequency levels. Stable operation at the nominal voltage and frequency values is also essential to establishing DG OPERABILITY, but a time constraint is not imposed. This is because a typical DG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not damped out by load application. This period may extend beyond the 10 second acceptance criteria and could be a cause for failing the SR. In lieu of a time constraint in the SR, PBAPS will monitor and trend the actual time to reach steady state operation as a means of ensuring there is no voltage regulator or governor degradation which could cause a DG to become inoperable.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.20 (continued)

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 8). This SR is modified by two Notes. The reason for Note 1 is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations. To minimize testing of the DGs, Note 2 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit. If a DG fails one of these Surveillances, a DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.21

With the exception of this Surveillance, all other Surveillances of this Specification (SR 3.8.1.1 through SR 3.8.1.20) are applied only to the Unit 2 AC sources. This Surveillance is provided to direct that the appropriate Surveillances for the required Unit 3 AC sources are governed by the applicable Unit 3 Technical Specifications. Performance of the applicable Unit 3 Surveillances will satisfy Unit 3 requirements, as well as satisfying this Unit 2 Surveillance Requirement. Six exceptions are noted to the Unit 3 SRs of LCO 3.8.1. SR 3.8.1.8 is excepted when only one Unit 3 offsite circuit is required by the Unit 2 Specification, since there is not a second circuit to transfer to. SR 3.8.1.12, SR 3.8.1.13, SR 3.8.1.17, SR 3.8.1.18 (ECCS load block requirements only), and SR 3.8.1.19 are excepted since these SRs test the Unit 3 ECCS initiation signal, which is not needed for the AC sources to be OPERABLE on Unit 2.

The Frequency required by the applicable Unit 3 SR also governs performance of that SR for Unit 2.

As Noted, if Unit 3 is in MODE 4 or 5, or moving irradiated fuel assemblies in the secondary containment, the Note to Unit 3 SR 3.8.2.1 is applicable. This ensures that a Unit 2 SR will not require a Unit 3 SR to be performed, when the

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.8.1.21 (continued) Unit 3 Technical Specifications exempts performance of a Unit 3 SR (However, as stated in the Unit 3 SR 3.8.2.1 Note, while performance of an SR is exempted, the SR still must be met).
REFERENCES	1. UFSAR, Sections 1.5 and 8.4.2. 2. UFSAR, Sections 8.3 and 8.4. 3. Regulatory Guide 1.9, July 1993. 4. UFSAR, Chapter 14. 5. Generic Letter 84-15. 6. Regulatory Guide 1.93, December 1974. 7. UFSAR, Section 1.5.1. 8. Regulatory Guide 1.108, August 1977. 9. Regulatory Guide 1.137, October 1979. 10. UFSAR, Section 8.5.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources—Shutdown

BASES

BACKGROUND

A description of the AC sources is provided in the Bases for LCO 3.8.1, "AC Sources—Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC sources during MODES 4 and 5 and during movement of irradiated fuel assemblies in secondary containment ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.

In general, when the unit is shut down the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or loss of all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, and 3 have no specific analyses in MODES 4 and 5. Worst case bounding events are deemed not credible in MODES 4 and 5 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and corresponding stresses result in the probabilities of occurrences significantly reduced or eliminated, and minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

During MODES 1, 2, and 3, various deviations from the analysis assumptions and design requirements are allowed within the ACTIONS. This allowance is in recognition that

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

certain testing and maintenance activities must be conducted, provided an acceptable level of risk is not exceeded. During MODES 4 and 5, performance of a significant number of required testing and maintenance activities is also required. In MODES 4 and 5, the activities are generally planned and administratively controlled. Relaxations from typical MODES 1, 2, and 3 LCO requirements are acceptable during shutdown MODES, based on:

a. The fact that time in an outage is limited. This is a risk prudent goal as well as a utility economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operation MODE analyses, or both.

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODES 1, 2, and 3 OPERABILITY requirements) with systems assumed to function during an event.

In the event of an accident during shutdown, this LCO ensures the capability of supporting systems necessary for avoiding immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite (diesel generator (DG)) power.

The AC sources satisfy Criterion 3 of the NRC Policy Statement.

LCO

One offsite circuit supplying the Unit 2 onsite Class 1E power distribution subsystem(s) of LCO 3.8.8, "Distribution Systems—Shutdown," ensures that all required Unit 2 powered loads are powered from offsite power. Two OPERABLE DGs, associated with the Unit 2 onsite Class 1E power distribution subsystem(s) required OPERABLE by LCO 3.8.8, ensures that a diverse power source is available for providing electrical power support assuming a loss of the

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BASES

LCO
(continued)

offsite circuit. In addition, some equipment that may be required by Unit 2 is powered from Unit 3 sources (e.g., Standby Gas Treatment (SGT) System). Therefore, one qualified circuit between the offsite transmission network and the Unit 3 onsite Class 1E AC electrical power distribution subsystem(s), and one DG (not necessarily a different DG than those being used to meet LCO 3.8.2.b requirements) capable of supplying power to one of the required Unit 3 subsystems of each of the required components must also be OPERABLE. Together, OPERABILITY of the required offsite circuit(s) and required DG(s) ensures the availability of sufficient AC sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and reactor vessel draindown).

The qualified Unit 2 offsite circuit must be capable of maintaining rated frequency and voltage while connected to the respective Unit 2 4 kV emergency bus(es), and of accepting required loads during an accident. Qualified offsite circuits are those that are described in the UFSAR and are part of the licensing basis for the unit. A Unit 2 offsite circuit consists of the incoming breaker and disconnect to the startup and emergency auxiliary transformer, the respective circuit path to the emergency auxiliary transformer, and the circuit path to the Unit 2 4 kV emergency buses required by LCO 3.8.8, including feeder breakers to the required Unit 2 4 kV emergency buses. A qualified Unit 3 offsite circuit's requirements are the same as the Unit 2 circuit's requirements, except that the circuit path, including the feeder breakers, is to the Unit 3 4 kV emergency buses required to be OPERABLE by LCO 3.8.8.

The required DGs must be capable of starting, accelerating to rated speed and voltage, and connecting to their respective Unit 2 emergency bus on detection of bus undervoltage. This sequence must be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the 4 kV emergency buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with engine hot and DG in standby with engine at ambient conditions. Additional

(continued)

BASES

LCO (continued)

DG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode. Proper sequencing of loads is a required function for DG OPERABILITY. The necessary portions of the Emergency Service Water System are also required to provide appropriate cooling to each required DG.

The OPERABILITY requirements for the DG capable of supplying power to the Unit 3 powered equipment are the same as described above, except that the required DG must be capable of connecting to its respective Unit 3 4 kV emergency bus. (In addition, the Unit 3 ECCS initiation logic SRs are not applicable, as described in SR 3.8.2.2 Bases.)

It is acceptable for 4 kV emergency buses to be cross tied during shutdown conditions, permitting a single offsite power circuit to supply all required buses. No automatic transfer capability is required for offsite circuits to be considered OPERABLE.

APPLICABILITY

The AC sources are required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment to provide assurance that:

a. Systems providing adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core in case of an inadvertent draindown of the reactor vessel;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

AC power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.1.

(continued)

BASES (continued)

ACTIONS

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

A.1 and B.1

With one or more required offsite circuits inoperable, or with one DG inoperable, the remaining required sources may be capable of supporting sufficient required features (e.g., system, subsystem, division, component, or device) to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel. For example, if two or more 4 kV emergency buses are required per LCO 3.8.8, one 4 kV emergency bus with offsite power available may be capable of supplying sufficient required features. By the allowance of the option to declare required features inoperable that are not powered from offsite power (Required Action A.1) or capable of being powered by the required DG (Required Action B.1), appropriate restrictions can be implemented in accordance with the affected feature(s) LCOs' ACTIONS. Required features remaining powered from a qualified offsite power circuit, even if that circuit is considered inoperable because it is not powering other required features, are not declared inoperable by this Required Action. If a single DG is credited with meeting both LCO 3.8.2.d and one of the DG requirements of LCO 3.8.2.b, then the required features remaining capable of being powered by the DG are not declared inoperable by this Required Action, even if the DG is considered inoperable because it is not capable of powering other required features.

A.2.1, A.2.2, A.2.3, A.2.4, B.2.1, B.2.2, B.2.3, B.2.4, C.1, C.2, C.3, and C.4

With an offsite circuit not available to all required 4 kV emergency buses or one required DG inoperable, the option still exists to declare all required features inoperable

(continued)

BASES

ACTIONS

A.2.1, A.2.2, A.2.3, A.2.4, B.2.1, B.2.2, B.2.3, B.2.4, C.1, C.2, C.3, and C.4 (continued)

(per Required Actions A.1 and B.1). Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. With two or more required DGs inoperable, the minimum required diversity of AC power sources may not be available. It is, therefore, required to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in the secondary containment, and activities that could result in inadvertent draining of the reactor vessel.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC sources and to continue this action until restoration is accomplished in order to provide the necessary AC power to the plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A have been modified by a Note to indicate that when Condition A is entered with no AC power to any required 4 kV emergency bus, ACTIONS for LCO 3.8.8 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit whether or not a required bus is de-energized. LCO 3.8.8 provides the appropriate restrictions for the situation involving a de-energized bus.

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the Unit 2 AC sources in other than MODES 1, 2, and 3. SR 3.8.1.8 is not

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1 (continued)

required to be met since only one offsite circuit is required to be OPERABLE. SR 3.8.1.17 is not required to be met because the required OPERABLE DG(s) is not required to undergo periods of being synchronized to the offsite circuit. SR 3.8.1.20 is excepted because starting independence is not required with the DG(s) that is not required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during the performance of SRs, and to preclude de-energizing a required 4 kV emergency bus or disconnecting a required offsite circuit during performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DG and offsite circuit are required to be OPERABLE.

SR 3.8.2.2

This Surveillance is provided to direct that the appropriate Surveillances for the required Unit 3 AC sources are governed by the Unit 3 Technical Specifications. Performance of the applicable Unit 3 Surveillances will satisfy Unit 3 requirements, as well as satisfying this Unit 2 Surveillance Requirement. Seven exceptions are noted to the Unit 3 SRs of LCO 3.8.1. SR 3.8.1.8 is excepted when only one Unit 3 offsite circuit is required by the Unit 2 Specification, since there is not a second circuit to transfer to. SR 3.8.1.12, SR 3.8.1.13, SR 3.8.1.17, SR 3.8.1.18 (ECCS load block requirements only), and SR 3.8.1.19 are excepted since these SRs test the Unit 3 ECCS initiation signal, which is not needed for the AC sources to be OPERABLE on Unit 2. SR 3.8.1.20 is excepted since starting independence is not required with the DG(s) that is not required to be OPERABLE.

The Frequency required by the applicable Unit 3 SR also governs performance of that SR for Unit 2.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.2.2 (continued)

As Noted, if Unit 3 is not in MODE 1, 2, or 3, the Note to Unit 3 SR 3.8.2.1 is applicable. This ensures that a Unit 2 SR will not require a Unit 3 SR to be performed, when the Unit 3 Technical Specifications exempts performance of a Unit 3 SR or when Unit 3 is defueled. (However, as stated in the Unit 3 SR 3.8.2.1 Note, while performance of an SR is exempted, the SR still must be met).

REFERENCES

None.

B 3.8 ELECTRICAL POWER SYSTEMS

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

BASES

BACKGROUND

Each of the four diesel generators (DGs) is provided with an associated storage tank which collectively have a fuel oil capacity sufficient to operate all four DGs for a period of 7 days while the DG is supplying maximum post loss of coolant accident (LOCA) load demand discussed in UFSAR, Section 8.5.2 (Ref. 1). The maximum load demand is calculated using the time dependent loading of each DG and the assumption that all four DGs are available. This onsite fuel oil capacity is sufficient to operate the DGs for longer than the time to replenish the onsite supply from outside sources. Post accident electrical loading and fuel consumption is not equally shared among the DGs. Therefore, it may be necessary to transfer post accident loads between DGs or to transfer fuel oil between storage tanks to achieve 7 days of post accident operation for all four DGs. Each storage tank contains sufficient fuel to support the operation of the DG with the heaviest load for greater than 6 days.

Each DG is equipped with a day tank and an associated fuel transfer pump that will automatically transfer oil from a fuel storage tank to the day tank of the associated DG when actuated by a float switch in the day tank. Additionally, the capability exists to transfer fuel oil between storage tanks. Redundancy of pumps and piping precludes the failure of one pump, or the rupture of any pipe valve, or tank to result in the loss of more than one DG. All outside tanks and piping are located underground.

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

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BASES

BACKGROUND (continued)

The DG lubrication system is designed to provide sufficient lubrication to permit proper operation of its associated DG under all loading conditions. The system is required to circulate the lube oil to the diesel engine working surfaces and to remove excess heat generated by friction during operation. Each engine oil sump and associated lube oil storage tank contain an inventory capable of supporting a minimum of 7 days of operation. Each lube oil sump utilizes a mechanical float-type level controller to automatically maintain the sump at the "full level running" level via gravity feed from the associated lube oil storage tank. Onsite storage of lube oil also helps ensure a 7 day supply is maintained. This supply is sufficient to allow the operator to replenish lube oil from outside sources.

Each DG has an air start system that includes two air start receivers; each with adequate capacity for five successive normal starts on the DG without recharging the air start receiver.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in UFSAR, Chapter 8 (Ref. 4), and Chapter 14 (Ref. 5), assume Engineered Safety Feature (ESF) systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems.

Since diesel fuel oil, lube oil, and starting air subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of the NRC Policy Statement.

LCO

Stored diesel fuel oil is required to have sufficient supply for 7 days of operation at the worst case post accident time-dependent load profile. It is also required to meet specific standards for quality. Additionally, sufficient lube oil supply must be available to ensure the capability to operate at full load for 7 days. This requirement, in

(continued)

BASES

LCO (continued)

conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of DGs required to shut down both the Unit 2 and Unit 3 reactors and to maintain them in a safe condition for an abnormal operational transient or a postulated DBA in one unit with loss of offsite power. DG day tank fuel oil requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources—Operating," and LCO 3.8.2, "AC Sources—Shutdown."

The starting air system is required to have a minimum capacity for five successive DG normal starts without recharging the air start receivers. Only one air start receiver per DG is required, since each air start receiver has the required capacity.

APPLICABILITY

The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down both the Unit 2 and Unit 3 reactors and maintain them in a safe shutdown condition after an abnormal operational transient or a postulated DBA in either Unit 2 or Unit 3. Because stored diesel fuel oil, lube oil, and starting air subsystem support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil, lube oil, and starting air are required to be within limits when the associated DG is required to be OPERABLE.

ACTIONS

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

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ACTIONS (continued)

A.1

With fuel oil level < 29,000 gal in a storage tank, the 7 day fuel oil supply for a DG is not available. However, the Condition is restricted to fuel oil level reductions that maintain at least a 6 day supply. These circumstances may be caused by events such as:

a. Full load operation required for an inadvertent start while at minimum required level; or

b. Feed and bleed operations that may be necessitated by increasing particulate levels or any number of other oil quality degradations.

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

B.1

With lube oil inventory < 350 gal, sufficient lube oil to support 7 days of continuous DG operation at full load conditions may not be available. However, the Condition is restricted to lube oil volume reductions that maintain at least a 6 day supply. This restriction allows sufficient time for obtaining the requisite replacement volume. A period of 48 hours is considered sufficient to complete restoration of the required volume prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the low rate of usage, the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

(continued)

BASES

ACTIONS (continued)

C.1

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

D.1

With the new fuel oil properties defined in the Bases for SR 3.8.3.3 not within the required limits, a period of 30 days is allowed for restoring the stored fuel oil properties. This period provides sufficient time to test the stored fuel oil to determine that the new fuel oil, when mixed with previously stored fuel oil, remains acceptable, or to restore the stored fuel oil properties. This restoration may involve feed and bleed procedures, filtering, or combination of these procedures. Even if a DG start and load was required during this time interval and the fuel oil properties were outside limits, there is high likelihood that the DG would still be capable of performing its intended function.

E.1

With required starting air receiver pressure < 225 psig, sufficient capacity for five successive DG normal starts does not exist. However, as long as the receiver pressure is > 150 psig, there is adequate capacity for at least one start attempt, and the DG can be considered OPERABLE while

(continued)

BASES

ACTIONS

E.1 (continued)

the air receiver pressure is restored to the required limit. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the DG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most DG starts are accomplished on the first attempt, and the low probability of an event during this brief period.

F.1

With a Required Action and associated Completion Time of Condition A, B, C, D, or E not met, or the stored diesel fuel oil, lube oil, or starting air subsystem not within limits for reasons other than addressed by Conditions A through E, the associated DG may be incapable of performing its intended function and must be immediately declared inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate useable inventory of fuel oil in the storage tanks to support each DG's operation of all four DGs for 7 days at the worst case post accident time-dependent load profile. The 7 day period is sufficient time to place both Unit 2 and Unit 3 in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

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

SR 3.8.3.2

This Surveillance ensures that sufficient lubricating oil inventory (combined inventory in the DG lube oil sump, lube oil storage tank, and in the warehouse) is available to support at least 7 days of full load operation for each DG. The 350 gal requirement is conservative with respect to the DG manufacturer's consumption values for the run time of the DG. Implicit in this SR is the requirement to verify the

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.2 (continued)

capability to transfer the lube oil from its storage location to the DG to maintain adequate inventory for 7 days of full load operation without the level reaching the manufacturer's recommended minimum level.

A 31 day Frequency is adequate to ensure that a sufficient lube oil supply is onsite, since DG starts and run time are closely monitored by the plant staff.

SR 3.8.3.3

The tests of new fuel oil prior to addition to the storage tanks are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between the sample (and corresponding results) of new fuel and addition of new fuel oil to the storage tanks to exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4057-81 (Ref. 6);

b. Verify in accordance with the tests specified in ASTM D975-81 (Ref. 6) as discussed in Reference 7 that the sample has a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes (if specific gravity was not determined by comparison with the supplier's certification), and a flash point of ≥ 125°F;

c. Verify in accordance with tests specified in ASTM D1298-80 (Ref. 6) as discussed in Reference 7 that the sample has an absolute specific gravity at 60/60°F of ≥ 0.83 and ≤ 0.89, or an absolute specific gravity of within 0.0016 at 60/60°F when compared to the supplier's certificate, or an API gravity at 60°F of ≥ 27° and ≤ 39°, or an API gravity of within 0.3° at 60°F when compared to the supplier's certification; and

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

d. Verify that the new fuel oil has a clear and bright appearance with proper color when tested in accordance with ASTM D4176-82 (Ref. 6) as discussed in Reference 7; or verify, in accordance with ASTM D975-81 (Ref. 6), that the sample has a water and sediment content ≤ 0.05 volume percent when dyes have been intentionally added to fuel oil (for example due to sulfur content).

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

Following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-81 (Ref. 6) are met for new fuel oil when tested in accordance with ASTM D975-81 (Ref. 6) as discussed in Reference 7, except that the analysis for sulfur may be performed in accordance with ASTM D1552-79 (Ref. 6) or ASTM D2622-82 (Ref. 6) as discussed in Reference 7. These additional analyses are required by Specification 5.5.9, "Diesel Fuel Oil Testing Program," to be performed within 31 days following sampling and addition. This 31 day requirement is intended to assure that: 1) the new fuel oil sample taken is no more than 31 days old at the time of adding the new fuel oil to the DG storage tank, and 2) the results of the new fuel oil sample are obtained within 31 days after addition of the new fuel oil to the DG storage tank. The 31 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate effect on DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs.

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

Particulate concentrations should be determined in accordance with ASTM D2276-78 (Ref. 6), Method A, as discussed in Reference 7 except that the filters specified

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

in ASTM D2276-78, (Sections 3.1.6 and 3.1.7) may have a nominal pore size up to three microns. This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing. For the Peach Bottom Atomic Power Station design in which the total volume of stored fuel oil is contained in four interconnected tanks, each tank must be considered and tested separately.

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

SR 3.8.3.4

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each DG is available. The system design requirements provide for a minimum of five normal engine starts without recharging. The pressure specified in this SR is intended to reflect the lowest value at which the five starts can be accomplished.

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

SR 3.8.3.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel storage tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.5 (continued)

breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are consistent with Regulatory Guide 1.137 (Ref. 2). This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during performance of the Surveillance.

REFERENCES

1. UFSAR, Section 8.5.2.
2. Regulatory Guide 1.137, Revision 1.
3. ANSI N195, 1976.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 14.
6. ASTM Standards: D4057-81; D975-81; D1298-80; D4176-82; D1552-79; D2622-82; and D2276-78.
7. Letter from G. A. Hunger (PECO Energy) to USNRC Document Control Desk; Peach Bottom Atomic Power Station Units 2 and 3, Supplement 7 to TSCR 93-16, Conversion to Improved Technical Specifications; dated May 24, 1995.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources—Operating

BASES

BACKGROUND

The DC electrical power system provides the AC emergency power system with control power. It also provides a source of reliable, uninterruptible 125/250 VDC power and 125 VDC control power and instrument power to Class 1E and non-Class 1E loads during normal operation and for safe shutdown of the plant following any plant design basis event or accident as documented in the UFSAR (Ref. 1), independent of AC power availability. The DC Electrical Power System meets the intent of the Proposed IEEE Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations (Ref. 2). The DC electrical power system is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure.

The DC power sources provide both motive and control power, and instrument power, to selected safety related equipment, as well as to the nonsafety related equipment. There are two independent divisions per unit, designated Division I and Division II. Each division consists of two 125 VDC batteries. The two 125 VDC batteries in each division are connected in series. Each 125 VDC battery has two chargers (one normally inservice charger and one spare charger) that are exclusively associated with that battery and cannot be interconnected with any other 125 VDC battery. The chargers are supplied from separate 480 V motor control centers (MCCs). Each of these MCCs is connected to an independent emergency AC bus. Some of the chargers are capable of being supplied by Unit 3 MCCs, which receive power from a 4 kV emergency bus, via manual transfer switches. However, for a required battery charger to be considered OPERABLE when the unit is in MODE 1, 2, or 3, it must receive power from its associated Unit 2 MCC. The safety related loads between the 125/250 VDC subsystem are not transferable except for the Automatic Depressurization System (ADS) valves and logic circuits and the main steam safety/relief valves. The ADS logic circuits and valves and the main steam safety/relief valves are normally fed from the Division I DC system.

(continued)

BASES

BACKGROUND (continued)

During normal operation, the DC loads are powered from the battery chargers with the batteries floating on the system. In case of loss of normal power to the battery charger, the DC loads are powered from the batteries.

The DC power distribution system is described in more detail in Bases for LCO 3.8.7, "Distribution System—Operating," and LCO 3.8.8, "Distribution System—Shutdown."

Each battery has adequate storage capacity to carry the required load continuously for approximately 2 hours.

Each of the unit's two DC electrical power divisions, consisting of two 125 V batteries in series, four battery chargers (two normally inservice chargers and two spare chargers), and the corresponding control equipment and interconnecting cabling, is separately housed in a ventilated room apart from its chargers and distribution centers. Each division is separated electrically from the other division to ensure that a single failure in one division does not cause a failure in a redundant division. There is no sharing between redundant Class 1E divisions such as batteries, battery chargers, or distribution panels.

The batteries for DC electrical power subsystems are sized to produce required capacity at 80% of nameplate rating, corresponding to warranted capacity at end of life cycles and the 100% design demand. The minimum design voltage for sizing the battery using the methodology in IEEE 485 (Ref. 3) is based on a traditional 1.81 volts per cell at the end of a 2 hour load profile. The battery terminal voltage using 1.81 volts per cell is 105 V. Using the LOOP/LOCA load profile, the predicted value of the battery terminals is greater than 105 VDC at the end of the profile. Many 1E loads operate exclusively at the beginning of the profile and require greater than the design minimum terminal voltage. The analyzed voltage of the distribution panels and the MCCs is greater than that required during the LOOP/LOCA to support the operation of the 1E loads during the time period they are required to operate.

Each required battery charger of DC electrical power subsystem has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery

(continued)

BASES

BACKGROUND (continued)

bank fully charged. Each battery charger has sufficient capacity to restore the battery from the design minimum charge to its fully charged state within 20 hours while supplying normal steady state loads following a LOCA coincident with a loss of offsite power.

A description of the Unit 3 DC power sources is provided in the Bases for Unit 3 LCO 3.8.4, "DC Sources—Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 14 (Ref. 1), assume that Engineered Safety Feature (ESF) systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation. The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining DC sources OPERABLE during accident conditions in the event of:

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

b. A worst case single failure.

The DC sources satisfy Criterion 3 of the NRC Policy Statement.

LCO

The Unit 2 Division I and Division II DC electrical power subsystems, with each DC subsystem consisting of two 125 V station batteries in series, two battery chargers (one per battery), and the corresponding control equipment and interconnecting cabling supplying power to the associated bus, are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an abnormal operational transient or a postulated DBA. In addition, DC control power (which provides control power for the 4 kV load circuit breakers and the feeder breakers to the 4 kV emergency bus) for two of the four 4 kV emergency buses, as well as control power for two of the diesel generators, is provided by the Unit 3 DC electrical power subsystems. Therefore, Unit 3 Division I and Division II DC electrical power subsystems are also required to be OPERABLE. A Unit 3

(continued)

BASES

LCO (continued)	DC electrical power subsystem OPERABILITY requirements are the same as those required for a Unit 2 DC electrical power subsystem, except that the Unit 3: 1) Division I DC electrical power subsystem is allowed to consist of only the 125 V battery C, an associated battery charger, and the corresponding control equipment and interconnecting cabling supplying 125 V power to the associated bus; and 2) Division II DC electrical power subsystem is allowed to consist of only the 125 V battery D, an associated battery charger, and the corresponding control equipment and interconnecting cabling supplying 125 V power to the associated bus. This exception is allowed only if all 250 VDC loads are removed from the associated bus. In addition, a Unit 3 battery charger can be powered from a Unit 2 AC source, (as described in the Background section of the Bases for Unit 3 LCO 3.8.4, "DC Sources—Operating"), and be considered OPERABLE for the purposes of meeting this LCO. Thus, loss of any DC electrical power subsystem does not prevent the minimum safety function from being performed.

APPLICABILITY

The DC electrical power sources are required to be OPERABLE in MODES 1, 2, and 3 to ensure safe unit operation and to ensure that:

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

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

The DC electrical power requirements for MODES 4 and 5 are addressed in LCO 3.8.5, "DC Sources— Shutdown."

ACTIONS

A.1

Pursuant to LCO 3.0.6, the Distribution Systems—Operating ACTIONS would not be entered even if the DC electrical power subsystem inoperability resulted in de-energization of an AC or DC bus. Therefore, the Required Actions of Condition A are modified by a Note to indicate that when Condition A

(continued)

BASES

ACTIONS

A.1 (continued

results in de-energization of a Unit 2 4 kV emergency bus or a Unit 3 DC bus, Actions for LCO 3.8.7 must be immediately entered. This allows Condition A to provide requirements for the loss of a Unit 3 DC electrical power subsystem (due to performance of SR 3.8.4.7 or SR 3.8.4.8) without regard to whether a bus is de-energized. LCO 3.8.7 provides the appropriate restriction for a de-energized bus.

If one Unit 3 DC electrical power subsystem is inoperable due to performance of SR 3.8.4.7 or SR 3.8.4.8, the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. In the case of an inoperable Unit 3 DC electrical power subsystem, since a subsequent postulated worst case single failure could result in the loss of safety function, continued power operation should not exceed 7 days. The 7 day Completion Time is based upon the Unit 3 DC electrical power subsystem being inoperable due to performance of SR 3.8.4.7 or SR 3.8.4.8. Performance of these two SRs will result in inoperability of the Unit 3 DC divisional batteries since these batteries are needed for Unit 2 operation, more time is provided to restore the batteries, if the batteries are inoperable for performance of required Surveillances, to preclude the need for a dual unit shutdown to perform these Surveillances. The Unit 3 DC electrical power subsystems also do not provide power to the same type of equipment as the Unit 2 DC sources. The Completion Time also takes into account the capacity and capability of the remaining DC sources.

B.1

Pursuant to LCO 3.0.6, the Distribution Systems—Operating ACTIONS would not be entered even if the DC electrical power subsystem inoperability resulted in de-energization of an AC bus. Therefore, the Required Actions of Condition A are modified by a Note to indicate that when Condition A results in de-energization of a Unit 2 4 kV emergency bus, Actions for LCO 3.8.7 must be immediately entered. This allows Condition A to provide requirements for the loss of a Unit 3 DC electrical power subsystem without regard to whether a bus is de-energized. LCO 3.8.7 provides the appropriate restriction for a de-energized bus.

(continued)

BASES

ACTIONS

B.1 (continued)

If one of the Unit 3 DC electrical power subsystems is inoperable for reasons other than Condition A, the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure could, however, result in a loss of minimum necessary DC electrical subsystems to mitigate a worst case accident, continued power operation should not exceed 12 hours. The 12 hour Completion Time reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and takes into consideration the importance of the Unit 3 DC electrical power subsystem.

C.1

Condition C represents one Unit 2 division with a loss of ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation. It is therefore imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for complete loss of DC power.

If one of the Unit 2 DC electrical power subsystems is inoperable (e.g., inoperable battery/batteries, inoperable required battery charger/chargers, or inoperable required battery charger/chargers and associated battery/batteries), the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure could result in the loss of minimum necessary DC electrical subsystems to mitigate a worst case accident, continued power operation should not exceed 2 hours. The 2 hour Completion Time is consistent with Regulatory Guide 1.93 (Ref. 4) and reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power division and, if the Unit 2 DC electrical power division is not restored to OPERABLE status, to prepare to initiate an orderly and safe unit shutdown. The 2 hour limit is also consistent with the allowed time for an inoperable Unit 2 DC Distribution System division.

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BASES

ACTIONS (continued)

D.1 and D.2

If the DC electrical power subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 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. The Completion Time to bring the unit to MODE 4 is consistent with the time specified in Regulatory Guide 1.93 (Ref. 4).

E.1

Condition E corresponds to a level of degradation in the DC electrical power subsystems that causes a required safety function to be lost. When more than one DC source is lost, this results in a loss of a required function, thus the plant is in a condition outside the accident analysis. Therefore, no additional time is justified for continued operation. LCO 3.0.3 must be entered immediately to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

As Noted at the beginning of the SRs, SR 3.8.4.1 through SR 3.8.4.8 are applicable only to the Unit 2 DC electrical power subsystems and SR 3.8.4.9 is applicable only to the Unit 3 DC electrical power subsystems.

SR 3.8.4.1

Verifying battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the charging system and the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery (or battery cell) and maintain the battery (or a battery cell) in a fully charged state. The voltage requirements are

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1 (continued)

based on the minimum cell voltage that will maintain a charged cell. This is consistent with the assumptions in the battery sizing calculations. The SR must be performed every 7 days, unless (as specified by the Note in the Frequency) the battery is on equalize charge or has been on equalize charge any time during the previous 1 day. This allows the routine 7 day Frequency to be extended until such a time that the SR can be properly performed and meaningful results obtained. The 14 day Frequency is not modified by the Note, thus regardless of how often the battery is placed on equalize charge, the SR must be performed every 14 days.

SR 3.8.4.2

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

The battery connection resistance limits are established to maintain connection resistance as low as reasonably possible to minimize the overall voltage drop across the battery, and the possibility of battery damage due to heating of connections.

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

SR 3.8.4.3

Visual inspection of the battery cells, cell plates, and battery racks provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance. The presence of physical damage or deterioration does not necessarily represent a failure of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.3 (continued)

this SR, provided an evaluation determines that the physical damage or deterioration does not affect the OPERABILITY of the battery (its ability to perform its design function).

The 12 month Frequency for these SRs is consistent with IEEE-450 (Ref. 5), which recommends detailed visual inspection of cell condition and rack integrity on a yearly basis.

SR 3.8.4.4 and SR 3.8.4.5

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

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

The battery connection resistance limits are established to maintain connection resistance as low as reasonably possible to minimize the overall voltage drop across the battery, and the possibility of battery damage due to heating of connections.

The 12 month Frequency of these SRs is consistent with IEEE-450 (Ref. 5), which recommends detailed visual inspection of cell condition and inspection of cell to cell and terminal connection resistance on a yearly basis.

SR 3.8.4.6

Battery charger capability requirements are based on the design capacity of the chargers. The minimum charging capacity requirement is based on the capacity to maintain the associated battery in its fully charged condition, and

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.6 (continued)

to restore the battery to its fully charged condition following the worst case design discharge while supplying normal steady state loads. The minimum required amperes and duration ensures that these requirements can be satisfied.

The Frequency is acceptable, given battery charger reliability and the administrative controls existing to ensure adequate charger performance during these 24 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths. B

SR 3.8.4.7

A battery service test is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC Electrical Power System. The discharge rate and test length corresponds to the design duty cycle requirements.

The Frequency is acceptable, given the unit conditions required to perform the test and the other requirements existing to ensure adequate battery performance during these 24 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

This SR is modified by two Notes. Note 1 allows performance of either a modified performance discharge test or a performance discharge test (described in the Bases for SR 3.8.4.8) in lieu of a service test once per 60 months provided the test performed envelops the duty cycle of the battery. This substitution is acceptable because as long as the test current is greater than or equal to the actual duty cycle of the battery, SR 3.8.4.8 represents a more severe test of battery capacity than a service test. In addition, since PBAPS refueling outage cycle is 24 months, SR 3.8.4.8 is performed every 48 months to ensure the 60 month Frequency is met. Therefore, SR 3.8.4.8 is performed in lieu of SR 3.8.4.7 every second refueling outage.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.7 (continued)

The reason for Note 2 is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the Electrical Distribution System, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance.

SR 3.8.4.8

A battery performance discharge test is a test of the constant current capacity of a battery, performed between 3 and 30 days after an equalize charge of the battery, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

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

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

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.8; however, the discharge test may be

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.8 (continued)

used to satisfy SR 3.8.4.8 while satisfying the requirements of SR 3.8.4.7 at the same time only if the test envelops the duty cycle of the battery.

The acceptance criteria for this Surveillance is consistent with IEEE-450 (Ref. 5) and IEEE-485 (Ref. 3). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements.

The Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturers rating, the Surveillance Frequency is reduced to 12 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's rating. Degradation is indicated, according to IEEE-450 (Ref. 5), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is 10% below the manufacturer's rating. If the rate of discharge varies significantly from the previous discharge test, the absolute battery capacity may change significantly, resulting in a capacity drop exceeding the criteria specified above. This absolute battery capacity change could be a result of acid concentration in the plate material, which is not an indication of degradation. Therefore, results of tests with significant rate differences should be discussed with the vendor and evaluated to determine if degradation has occurred. All these Frequencies, with the exception of the 24 month Frequency, are consistent with the recommendations in IEEE-450 (Ref. 5). The 24 month Frequency is acceptable, given the battery has shown no signs of degradation, the unit conditions required to perform the test and other requirements existing to ensure battery performance during these 24 month intervals. In addition, the 24 month Frequency is intended to be consistent with expected fuel cycle lengths.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.8 (continued)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance. The DC batteries of the other unit are exempted from this restriction since they are required to be OPERABLE by both units and the Surveillance cannot be performed in the manner required by the Note without resulting in a dual unit shutdown.

SR 3.8.4.9

With the exception of this Surveillance, all other Surveillances of this Specification (SR 3.8.4.1 through SR 3.8.4.8) are applied only to the Unit 2 DC electrical power subsystems. This Surveillance is provided to direct that the appropriate Surveillances for the required Unit 3 DC electrical power subsystems are governed by the Unit 3 Technical Specifications. Performance of the applicable Unit 3 Surveillances will satisfy Unit 3 requirements, as well as satisfying this Unit 2 Surveillance Requirement.

The Frequency required by the applicable Unit 3 SR also governs performance of that SR for Unit 2. As Noted, if Unit 3 is in MODE 4 or 5, or moving irradiated fuel assemblies in the secondary containment, the Note to Unit 3 SR 3.8.5.1 is applicable. This ensures that a Unit 2 SR will not require a Unit 3 SR to be performed, when the Unit 3 Technical Specifications exempts performance of a Unit 3 SR. (However, as stated in the Unit 3 SR 3.8.5.1 Note, while performance of the SR is exempted, the SR still must be met.)

REFERENCES

1. UFSAR, Chapter 14.

2. "Proposed IEEE Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations," June 1969.

3. IEEE Standard 485, 1983.

(continued)

BASES

REFERENCES (continued)	4.	Regulatory Guide 1.93, December 1974.
	5.	IEEE Standard 450, 1987.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 DC Sources—Shutdown

BASES

BACKGROUND

A description of the DC sources is provided in the Bases for LCO 3.8.4, "DC Sources—Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the UFSAR, Chapter 14 (Ref. 1), assume that Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the diesel generators (DGs), emergency auxiliaries, and control and switching during all MODES of operation.

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum DC electrical power sources during MODES 4 and 5 and during movement of irradiated fuel assemblies in secondary containment ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate DC electrical power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.

The DC sources satisfy Criterion 3 of the NRC Policy Statement.

LCO

The Unit 2 DC electrical power subsystems, with each DC subsystem consisting of two 125 V station batteries in series, two battery chargers (one per battery), and the corresponding control equipment and interconnecting cabling supplying power to the associated bus, are required to be

(continued)

BASES

LCO (continued)	OPERABLE to support Unit 2 DC distribution subsystems required OPERABLE by LCO 3.8.8, "Distribution Systems—Shutdown." When the equipment required OPERABLE: 1) does not require 250 VDC from the DC electrical power subsystem; and 2) does not require 125 VDC from one of the two 125 V batteries of the DC electrical power subsystem, the Unit 2 DC electrical power subsystem requirements can be modified to only include one 125 V battery (the battery needed to provide power to required equipment), an associated battery charger, and the corresponding control equipment and interconnecting cabling supplying 125 V power to the associated bus. This exception is allowed only if all 250 VDC loads are removed from the associated bus. In addition, DC control power (which provides control power for the 4 kV load circuit breakers and the feeder breakers to the 4 kV emergency bus) for two of the four 4 kV emergency buses, as well as control power for two of the diesel generators, is provided by the Unit 3 DC electrical power subsystems. Therefore, the Unit 3 DC electrical power subsystems needed to support required components are also required to be OPERABLE. The Unit 3 DC electrical power subsystem OPERABILITY requirements are the same as those required for a Unit 2 DC electrical power subsystem. In addition, battery chargers (Unit 2 and Unit 3) can be powered from the opposite unit's AC source (as described in the Background section of the Bases for LCO 3.8.4, "DC Sources—Operating"), and be considered OPERABLE for the purpose of meeting this LCO. This requirement ensures the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and inadvertent reactor vessel draindown).
APPLICABILITY	The DC electrical power sources required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment provide assurance that: a. Required features to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core in case of an inadvertent draindown of the reactor vessel;

(continued)

BASES

APPLICABILITY (continued)

b. Required features needed to mitigate a fuel handling accident are available;

c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The DC electrical power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.4.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

A.1, A.2.1, A.2.2, A.2.3, and A.2.4

If more than one DC distribution subsystem is required according to LCO 3.8.8, the DC electrical power subsystems remaining OPERABLE with one or more DC electrical power subsystems inoperable may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel.

By allowance of the option to declare required features inoperable with associated DC electrical power subsystems inoperable, appropriate restrictions are implemented in accordance with the affected system LCOs' ACTIONS. However, in many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in secondary containment, and any activities that could result in inadvertent draining of the reactor vessel).

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4 (continued)

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required DC electrical power subsystems and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required DC electrical power subsystems should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 requires performance of all Surveillances required by SR 3.8.4.1 through SR 3.8.4.8. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC electrical power subsystems from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

SR 3.8.5.2

This Surveillance is provided to direct that the appropriate Surveillances for the required Unit 3 DC electrical power subsystems are governed by the Unit 3 Technical Specifications. Performance of the applicable Unit 3 Surveillances will satisfy Unit 3 requirements, as well as satisfying this Unit 2 Surveillance Requirement. The Frequency required by the applicable Unit 3 SR also governs performance of that SR for Unit 2.

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BASES

SURVEILLANCE REQUIREMENTS	SR 3.8.5.2 (continued) As Noted, if Unit 3 is in MODE 4 or 5, or moving irradiated fuel assemblies in the secondary containment, the Note to Unit 3 SR 3.8.5.1 is applicable. This ensures that a Unit 2 SR will not require a Unit 3 SR to be performed, when the Unit 3 Technical Specifications exempts performance of a Unit 3 SR. (However, as stated in the Unit 3 SR 3.8.5.1 Note, while performance of an SR is exempted, the SR still must be met.)
REFERENCES	1. UFSAR, Chapter 14.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Cell Parameters

BASES

BACKGROUND	This LCO delineates the limits on electrolyte temperature, level, float voltage, and specific gravity for the DC electrical power subsystems batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.4, "DC Sources—Operating," and LCO 3.8.5, "DC Sources—Shutdown."
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident (DBA) and transient analyses in UFSAR, Chapter 14 (Ref. 1), assume Engineered Safety Feature systems are OPERABLE. The DC electrical power subsystems provide normal and emergency DC electrical power for the diesel generators (DGs), emergency auxiliaries, and control and switching during all MODES of operation. The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit as discussed in the Bases of LCO 3.8.4, "DC Sources—Operating," and LCO 3.8.5, "DC Sources—Shutdown. Since battery cell parameters support the operation of the DC electrical power subsystems, they satisfy Criterion 3 of the NRC Policy Statement.
LCO	Battery cell parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an abnormal operational transient or a postulated DBA. Electrolyte limits are conservatively established, allowing continued DC electrical system function even with Category A and B limits not met.
APPLICABILITY	The battery cell parameters are required solely for the support of the associated DC electrical power subsystem. Therefore, these cell parameters are only required when the DC power source is required to be OPERABLE. Refer to the Applicability discussions in Bases for LCO 3.8.4 and LCO 3.8.5.

(continued)

BASES (continued)

ACTIONS

A.1, A.2, and A.3

With parameters of one or more cells in one or more batteries not within limits (i.e., Category A limits not met or Category B limits not met, or Category A and B limits not met) but within the Category C limits specified in Table 3.8.6-1, the battery is degraded but there is still sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of Category A or B limits not met, and continued operation is permitted for a limited period.

The pilot cell electrolyte level and float voltage are required to be verified to meet the Category C limits within 1 hour (Required Action A.1). This check provides a quick indication of the status of the remainder of the battery cells. One hour provides time to inspect the electrolyte level and to confirm the float voltage of the pilot cells. One hour is considered a reasonable amount of time to perform the required verification.

Verification that the Category C limits are met (Required Action A.2) provides assurance that during the time needed to restore the parameters to the Category A and B limits, the battery is still capable of performing its intended function. A period of 24 hours is allowed to complete the initial verification because specific gravity measurements must be obtained for each connected cell. Taking into consideration both the time required to perform the required verification and the assurance that the battery cell parameters are not severely degraded, this time is considered reasonable. The verification is repeated at 7 day intervals until the parameters are restored to Category A or B limits. This periodic verification is consistent with the normal Frequency of pilot cell surveillances.

Continued operation is only permitted for 31 days before battery cell parameters must be restored to within Category A and B limits. Taking into consideration that, while battery capacity is degraded, sufficient capacity exists to perform the intended function and to allow time to fully restore the battery cell parameters to normal limits, this time is acceptable for operation prior to declaring the DC batteries inoperable.

(continued)

BASES

ACTIONS (continued)

B.1

When any battery parameter is outside the Category C limit for any connected cell, sufficient capacity to supply the maximum expected load requirement is not ensured and the corresponding DC electrical power subsystem must be declared inoperable. Additionally, other potentially extreme conditions, such as not completing the Required Actions of Condition A within the required Completion Time or average electrolyte temperature of representative cells falling below 40°F, also are cause for immediately declaring the associated DC electrical power subsystem inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

This SR verifies that Category A battery cell parameters are consistent with IEEE-450 (Ref. 2), which recommends regular battery inspections (at least one per month) including voltage, specific gravity, and electrolyte temperature of pilot cells. The SR must be performed every 7 days, unless (as specified by the Note in the Frequency) the battery is on equalize charge or has been on equalize charge any time during the previous 4 days. This allows the routine 7 day Frequency to be extended until such a time that the SR can be properly performed and meaningful results obtained. The 14 day Frequency is not modified by the Note, thus regardless of how often the battery is placed on equalize charge, the SR must be performed every 14 days.

SR 3.8.6.2

The quarterly inspection of specific gravity and voltage is consistent with IEEE-450 (Ref. 2). In addition, within 24 hours of a battery discharge < 100 V or within 24 hours of a battery overcharge > 145 V, the battery must be demonstrated to meet Category B limits. Transients, such as motor starting transients which may momentarily cause battery voltage to drop to ≤ 100 V, do not constitute battery discharge provided the battery terminal voltage and float current return to pre-transient values. This inspection is also consistent with IEEE-450 (Ref. 2), which recommends special inspections following a severe discharge or overcharge, to ensure that no significant degradation of the battery occurs as a consequence of such discharge or overcharge.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.6.3

This Surveillance verification that the average temperature of representative cells is within limits is consistent with a recommendation of IEEE-450 (Ref. 2) that states that the temperature of electrolytes in representative cells should be determined on a quarterly basis.

Lower than normal temperatures act to inhibit or reduce battery capacity. This SR ensures that the operating temperatures remain within an acceptable operating range.

Table 3.8.6-1

This table delineates the limits on electrolyte level, float voltage, and specific gravity for three different categories. The meaning of each category is discussed below.

Category A defines the normal parameter limit for each designated pilot cell in each battery. The cells selected as pilot cells are those whose temperature, voltage, and electrolyte specific gravity approximate the state of charge of the entire battery.

The Category A limits specified for electrolyte level are based on manufacturer's recommendations and are consistent with the guidance in IEEE-450 (Ref. 2), with the extra ½ inch allowance above the high water level indication for operating margin to account for temperature and charge effects. In addition to this allowance, footnote a to Table 3.8.6-1 permits the electrolyte level to be above the specified maximum level during equalizing charge, provided it is not overflowing. These limits ensure that the plates suffer no physical damage, and that adequate electron transfer capability is maintained in the event of transient conditions. IEEE-450 (Ref. 2) recommends that electrolyte level readings should be made only after the battery has been at float charge for at least 72 hours.

The Category A limit specified for float voltage is ≥ 2.13 V per cell. This value is based on the recommendation of IEEE-450 (Ref. 2), which states that prolonged operation of cells below 2.13 V can reduce the life expectancy of cells. The Category A limit specified for specific gravity for each pilot cell is ≥ 1.195 (0.020 below the manufacturer's fully

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

charged nominal specific gravity or a battery charging current that had stabilized at a low value). This value is characteristic of a charged cell with adequate capacity. According to IEEE-450 (Ref. 2), the specific gravity readings are based on a temperature of 77°F (25°C).

The specific gravity readings are corrected for actual electrolyte temperature and level. For each 3°F (1.67°C) above 77°F (25°C), 1 point (0.001) is added to the reading; 1 point is subtracted for each 3°F below 77°F. The specific gravity of the electrolyte in a cell increases with a loss of water due to electrolysis or evaporation. Level correction will be in accordance with manufacturer's recommendations.

Category B defines the normal parameter limits for each connected cell. The term "connected cell" excludes any battery cell that may be jumpered out.

The Category B limits specified for electrolyte level and float voltage are the same as those specified for Category A and have been discussed above. The Category B limit specified for specific gravity for each connected cell is ≥ 1.195 (0.020 below the manufacturer's fully charged, nominal specific gravity) with the average of all connected cells 1.205 (0.010 below the manufacturer's fully charged, nominal specific gravity). These values were developed from manufacturer's recommendations. The minimum specific gravity value required for each cell ensures that the effects of a highly charged or newly installed cell do not mask overall degradation of the battery.

Category C defines the limit for each connected cell. These values, although reduced, provide assurance that sufficient capacity exists to perform the intended function and maintain a margin of safety. When any battery parameter is outside the Category C limit, the assurance of sufficient capacity described above no longer exists, and the battery must be declared inoperable.

The Category C limit specified for electrolyte level (above the top of the plates and not overflowing) ensure that the plates suffer no physical damage and maintain adequate electron transfer capability. The Category C Allowable Value for voltage is based on IEEE-450 (Ref. 2), which

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

states that a cell voltage of 2.07 V or below, under float conditions and not caused by elevated temperature of the cell, indicates internal cell problems and may require cell replacement.

The Category C limit of average specific gravity ≥ 1.190, is based on manufacturer's recommendations. In addition to that limit, it is required that the specific gravity for each connected cell must be no less than 0.020 below the average of all connected cells. This limit ensures that the effect of a highly charged or new cell does not mask overall degradation of the battery.

The footnotes to Table 3.8.6-1 that apply to specific gravity are applicable to Category A, B, and C specific gravity. Footnote b of Table 3.8.6-1 requires the above mentioned correction for electrolyte level and temperature, with the exception that level correction is not required when battery charging current, while on float charge, is < 1 amp. This current provides, in general, an indication of overall battery condition.

Because of specific gravity gradients that are produced during the recharging process, delays of several days may occur while waiting for the specific gravity to stabilize. A stabilized charger current is an acceptable alternative to specific gravity measurement for determining the state of charge of the designated pilot cell. This phenomenon is discussed in IEEE-450 (Ref. 2). Footnote c to Table 3.8.6-1 allows the float charge current to be used as an alternate to specific gravity for up to 180 days following a battery recharge after a deep discharge. Within 180 days each connected cell's specific gravity must be measured to confirm the state of charge. Following a minor battery recharge (such as equalizing charge that does not follow a deep discharge) specific gravity gradients are not significant, and confirming measurements must be made within 30 days.

REFERENCES

1. UFSAR, Chapter 14.

2. IEEE Standard 450, 1987.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Distribution Systems—Operating

BASES

BACKGROUND

The onsite Class 1E AC and DC electrical power distribution system is divided into redundant and independent AC and DC electrical power distribution subsystems.

The primary AC distribution system for Unit 2 consists of four 4 kV emergency buses each having two offsite sources of power as well as an onsite diesel generator (DG) source. Each 4 kV emergency bus is connected to its normal source of power via either emergency auxiliary transformer no. 2 or no. 3. During a loss of the normal supply of offsite power to the 4 kV emergency buses, the alternate supply breaker from the alternate supply of offsite power for the 4 kV emergency buses attempts to close. If all offsite sources are unavailable, the onsite emergency DGs supply power to the 4 kV emergency buses. (However, these supply breakers are not governed by this LCO; they are governed by LCO 3.8.1, "AC Sources—Operating".)

The secondary plant distribution system for Unit 2 includes 480 VAC load centers E124, E224, E324, and E424.

There are two independent 125/250 VDC electrical power distribution subsystems for Unit 2 that support the necessary power for ESF functions.

In addition, since some components required by Unit 2 receive power through Unit 3 electrical power distribution subsystems, the Unit 3 AC and DC electrical power distribution subsystems needed to support the required equipment are also addressed in LCO 3.8.7. A description of the Unit 3 AC and DC Electrical Power Distribution System is provided in the Bases for Unit 3 LCO 3.8.7, "Distribution System—Operating."

The list of required Unit 2 distribution buses is presented in Table B 3.8.7-1.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 14 (Ref. 1), assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC and DC electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6 Containment Systems.

The OPERABILITY of the AC and DC electrical power distribution subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining distribution systems OPERABLE during accident conditions in the event of:

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

b. A postulated worst case single failure.

The AC and DC electrical power distribution system satisfies Criterion 3 of the NRC Policy Statement.

LCO

The Unit 2 AC and DC electrical power distribution subsystems are required to be OPERABLE. The required Unit 2 electrical power distribution subsystems listed in Table B 3.8.7-1 ensure the availability of AC and DC electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an abnormal operational transient or a postulated DBA. As stated in the Table, each division of the AC and DC electrical power distribution systems is a subsystem. In addition, since some components required by Unit 2 receive power through Unit 3 electrical power distribution subsystems (e.g., Standby Gas Treatment (SGT) System, emergency heat sink components, and DC control power for two of the four 4 kV emergency buses, as well as control power for two of the diesel generators), the Unit 3 AC and DC

(continued)

BASES

LCO (continued)

electrical power distribution subsystems needed to support the required equipment must also be OPERABLE. The Unit 3 electrical power distribution subsystems that may be required are listed in Unit 3 Table B 3.8.7-1.

Maintaining the Unit 2 Division I and II and required Unit 3 AC and DC electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Therefore, a single failure within any system or within the electrical power distribution subsystems will not prevent safe shutdown of the reactor.

The Unit 2 and Unit 3 AC electrical power distribution subsystems require the associated buses and electrical circuits to be energized to their proper voltages. The Unit 2 and Unit 3 DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated batteries or chargers. However, when a Unit 3 DC electrical power subsystem is only required to have one 125 V battery and associated battery charger to be considered OPERABLE (as described in the LCO section of the Bases for LCO 3.8.4, "DC Sources—Operating"), the proper voltage to which the associated bus is required to be energized is lowered from 250 V to 125 V (as read from the associated battery charger).

Based on the number of safety significant electrical loads associated with each electrical power distribution component (i.e., bus, load center, or distribution panel) listed in Table B 3.8.7-1, if one or more of the electrical power distribution components within a division (listed in Table 3.8.7-1) becomes inoperable, entry into the appropriate ACTIONS of LCO 3.8.7 is required. Other electrical power distribution components such as motor control centers (MCC) and distribution panels, which help comprise the AC and DC distribution systems are not listed in Table B 3.8.7-1. The loss of electrical loads associated with these electrical power distribution components may not result in a complete loss of a redundant safety function necessary to shut down the reactor and maintain it in a safe condition. Therefore, should one or more of these electrical power distribution components become inoperable due to a failure not affecting the OPERABILITY of an electrical power distribution component listed in Table B 3.8.7-1 (e.g., a breaker supplying a single MCC fails open), the individual loads on the electrical power distribution component would be

(continued)

BASES

LCO (continued)

considered inoperable, and the appropriate Conditions and Required Actions of the LCOs governing the individual loads would be entered. If however, one or more of these electrical power distribution components is inoperable due to a failure also affecting the OPERABILITY of an electrical power distribution component listed in Table B 3.8.7-1 (e.g., loss of a 4 kV emergency bus, which results in de-energization of all electrical power distribution components powered from the 4 kV emergency bus), while these electrical power distribution components and individual loads are still considered inoperable, the Conditions and Required Actions of the LCO for the individual loads are not required to be entered, since LCO 3.0.6 allows this exception (i.e., the loads are inoperable due to the inoperability of a support system governed by a Technical Specification; the 4 kV emergency bus).

In addition, transfer switches between redundant safety related Unit 2 and Unit 3 AC and DC power distribution subsystems must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, which could cause the failure of a redundant subsystem and a loss of essential safety function(s). If any transfer switches are closed, the electrical power distribution subsystem which is not being powered from its normal source (i.e., it is being powered from its redundant electrical power distribution subsystem) is considered inoperable. This applies to the onsite, safety related, redundant electrical power distribution subsystems. It does not, however, preclude redundant Class 1E 4 kV emergency buses from being powered from the same offsite circuit.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

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

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

(continued)

BASES

APPLICABILITY (continued)

Electrical power distribution subsystem requirements for MODES 4 and 5 and other conditions in which AC and DC electrical power distribution subsystems are required, are covered in LCO 3.8.8, "Distribution Systems—Shutdown."

ACTIONS

A.1

Pursuant to LCO 3.0.6, the DC Sources—Operating ACTIONS would not be entered even if the AC electrical power distribution subsystem inoperability resulted in de-energization of a required battery charger. Therefore, the Required Actions of Condition A are modified by a Note to indicate that when Condition A results in de-energization of a required Unit 3 battery charger, Actions for LCO 3.8.4 must be immediately entered. This allows Condition A to provide requirements for the loss of a Unit 3 AC electrical power distribution subsystem without regard to whether a battery charger is de-energized. LCO 3.8.4 provides the appropriate restriction for a de-energized battery charger.

If one or more of the required Unit 3 AC electrical power distribution subsystems are inoperable, and a loss of function has not occurred as described in Condition F, the remaining AC electrical power distribution subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure could, however, result in the loss of certain safety functions, continued power operation should not exceed 7 days. The 7 day Completion Time takes into account the capacity and capability of the remaining AC electrical power distribution subsystems, and is based on the shortest restoration time allowed for the systems affected by the inoperable AC electrical power distribution subsystem in the respective system Specification.

B.1

If one of the Unit 3 DC electrical power distribution subsystems is inoperable, the remaining DC electrical power distribution subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure could, however, result in the loss of safety function, continued power operation should not exceed 12 hours. The 12 hour Completion Time

(continued)

BASES

ACTIONS

B.1 (continued)

reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power distribution subsystem and takes into consideration the importance of the Unit 3 DC electrical power distribution subsystem.

C.1

With one Unit 2 AC electrical power distribution subsystem inoperable, the remaining AC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the Unit 2 AC electrical power distribution subsystem must be restored to OPERABLE status within 8 hours.

The Condition C worst scenario is one 4 kV emergency bus without AC power (i.e., no offsite power to the 4 kV emergency bus and the associated DG inoperable). In this Condition, the unit is more vulnerable to a complete loss of Unit 2 AC power. It is, therefore, imperative that the unit operators' attention be focused on minimizing the potential for loss of power to the remaining buses by stabilizing the unit, and on restoring power to the affected bus(es). The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because:

a. There is a potential for decreased safety if the unit operators' attention is diverted from the evaluations and actions necessary to restore power to the affected bus(es) to the actions associated with taking the unit to shutdown within this time limit.

b. The potential for an event in conjunction with a single failure of a redundant component in the division with AC power. (The redundant component is verified OPERABLE in accordance with Specification 5.5.11, "Safety Function Determination Program (SFDP).")

(continued)

BASES

ACTIONS

C.1 (continued)

The second Completion Time for Required Action C.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.7.a. If Condition C is entered while, for instance, a Unit 2 DC bus is inoperable and subsequently returned OPERABLE, this LCO may already have been not met for up to 2 hours. This situation could lead to a total duration of 10 hours, since initial failure of the LCO, to restore the Unit 2 AC Electrical Power Distribution System. At this time a Unit 2 DC bus could again become inoperable, and Unit 2 AC Electrical Power Distribution System could be restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This results in establishing the "time zero" at the time LCO 3.8.7.a was initially not met, instead of at the time Condition C was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO 3.8.7.a indefinitely.

D.1

With one Unit 2 DC electrical power distribution subsystem inoperable, the remaining DC electrical power distribution subsystem is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the Unit 2 DC electrical power distribution subsystem must be restored to OPERABLE status within 2 hours.

Condition D represents one Unit 2 electrical power distribution subsystem without adequate DC power, potentially with both the battery(s) significantly degraded and the associated charger(s) nonfunctioning. In this situation the plant is significantly more vulnerable to a complete loss of all Unit 2 DC power. It is, therefore, imperative that the operator's attention focus on

(continued)

BASES

ACTIONS

D.1 (continued)

stabilizing the plant, minimizing the potential for loss of power to the remaining electrical power distribution subsystem, and restoring power to the affected electrical power distribution subsystem.

This 2 hour limit is more conservative than Completion Times allowed for the majority of components that would be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

a. The potential for decreased safety when requiring a change in plant conditions (i.e., requiring a shutdown) while not allowing stable operations to continue;

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

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

The 2 hour Completion Time for DC electrical power distribution subsystems is consistent with Regulatory Guide 1.93 (Ref. 2).

The second Completion Time for Required Action D.1 establishes a limit on the maximum time allowed for any combination of required electrical power distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.7.a. If Condition D is entered while, for instance, a Unit 2 AC bus is inoperable and subsequently restored OPERABLE, LCO 3.8.7.a may already have been not met for up to 8 hours. This situation could lead to a total duration of 10 hours, since initial failure of LCO 3.8.7.a, to restore the Unit 2 DC Electrical Power Distribution System. At this time, a Unit 2 AC bus could again become inoperable, and Unit 2 DC Electrical Power Distribution System could be restored OPERABLE. This could continue indefinitely.

(continued)

BASES

ACTIONS

D.1 (continued)

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This allowance results in establishing the "time zero" at the time LCO 3.8.7.a was initially not met, instead of at the time Condition D was entered. The 16 hour Completion Time is an acceptable limitation on this potential of failing to meet the LCO indefinitely.

E.1 and E.2

If the inoperable electrical power distribution subsystem cannot be restored to OPERABLE status within the associated Completion Time, the unit 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.

F.1

Condition F corresponds to a level of degradation in the electrical power distribution system that causes a required safety function to be lost. When more than one Condition is entered, and this results in the loss of a required function, the plant is in a condition outside the accident analysis. Therefore, no additional time is justified for continued operation. LCO 3.0.3 must be entered immediately to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the AC and DC electrical power distribution systems are functioning properly, with the correct circuit breaker alignment (for the AC electrical power distribution system only). The correct AC breaker alignment ensures the appropriate separation and independence of the electrical buses are maintained, and power is available to each required bus. The verification of indicated power availability on the AC and DC buses

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1 (continued)

ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. This may be performed by verification of absence of low voltage alarms. The 7 day Frequency takes into account the redundant capability of the AC and DC electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. UFSAR, Chapter 14.

2. Regulatory Guide 1.93, December 1974.

Table B 3.8.7-1 (page 1 of 1)
AC and DC Electrical Power Distribution Systems

TYPE	VOLTAGE	DIVISION I*	DIVISION II*
AC buses	4160 V	Emergency Buses E12, E32	Emergency Buses E22, E42
	480 V	Load Centers E124, E324	Load Centers E224, E424
DC buses	250 V	Distribution Panel 2AD18	Distribution Panel 2BD18

* Each division of the AC and DC electrical power distribution systems is a subsystem.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Distribution Systems—Shutdown

BASES

BACKGROUND	A description of the AC and DC electrical power distribution system is provided in the Bases for LCO 3.8.7, "Distribution Systems—Operating."
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident and transient analyses in the UFSAR, Chapter 14 (Ref. 1), assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC and DC electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. The OPERABILITY of the AC and DC electrical power distribution system is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY. The OPERABILITY of the minimum AC and DC electrical power sources and associated power distribution subsystems during MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment ensures that: a. The facility can be maintained in the shutdown or refueling condition for extended periods; b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and c. Adequate power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident. The AC and DC electrical power distribution systems satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

Various combinations of subsystems, equipment, and components are required OPERABLE by other LCOs, depending on the specific plant condition. Implicit in those requirements is the required OPERABILITY of necessary support required features. This LCO explicitly requires energization of the portions of the Unit 2 electrical distribution system necessary to support OPERABILITY of Technical Specifications required systems, equipment, and components—both specifically addressed by their own LCO, and implicitly required by the definition of OPERABILITY. In addition, some components that may be required by Unit 2 receive power through Unit 3 electrical power distribution subsystems (e.g., Standby Gas Treatment (SGT) System and DC control power for two of the four 4 kV emergency buses, as well as control power for two of the diesel generators). Therefore, Unit 3 AC and DC electrical power distribution subsystems needed to support the required equipment must also be OPERABLE.

In addition, it is acceptable for required buses to be cross-tied during shutdown conditions, permitting a single source to supply multiple redundant buses, provided the source is capable of maintaining proper frequency (if required) and voltage.

Maintaining these portions of the distribution system energized ensures the availability of sufficient power to operate the plant in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and inadvertent reactor vessel draindown).

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core in case of an inadvertent draindown of the reactor vessel;

b. Systems needed to mitigate a fuel handling accident are available;

(continued)

BASES

APPLICABILITY (continued)

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The AC and DC electrical power distribution subsystem requirements for MODES 1, 2, and 3 are covered in LCO 3.8.7.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5

Although redundant required features may require redundant electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel. By allowing the option to declare required features inoperable with associated electrical power distribution subsystems inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystem LCO's Required Actions. However, in many instances this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made, (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in the secondary containment, and any activities that could result in inadvertent draining of the reactor vessel).

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5 (continued)

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC and DC electrical power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the plant safety systems.

Notwithstanding performance of the above conservative Required Actions, a required residual heat removal-shutdown cooling (RHR-SDC) subsystem may be inoperable. In this case, Required Actions A.2.1 through A.2.4 do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the RHR-SDC ACTIONS would not be entered. Therefore, Required Action A.2.5 is provided to direct declaring RHR-SDC inoperable, which results in taking the appropriate RHR-SDC ACTIONS.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required electrical power distribution subsystems should be completed as quickly as possible in order to minimize the time the plant safety systems may be without power.

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the AC and DC electrical power distribution subsystem is functioning properly, with the buses energized. The verification of indicated power availability on the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. This may be performed by verification of absence of low voltage alarms. The 7 day Frequency takes into account the redundant capability of the electrical power distribution subsystems, as well as other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. UFSAR, Chapter 14.

BASES

APPLICABLE SAFETY ANALYSES (continued)	As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.
LCO	As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Control rod testing may be performed in compliance with the prescribed sequences of LCO 3.1.6, and during these tests, no exceptions to the requirements of LCO 3.1.6 are necessary. For testing performed with a sequence not in compliance with LCO 3.1.6, the requirements of LCO 3.1.6 may be suspended, provided additional administrative controls are placed on the test to ensure that the assumptions of the special safety analysis for the test sequence are satisfied. Assurances that the test sequence is followed can be provided by either programming the test sequence into the RWM, with conformance verified as specified in SR 3.3.2.1.8 and allowing the RWM to monitor control rod withdrawal and provide appropriate control rod blocks if necessary, or by verifying conformance to the approved test sequence by a second licensed operator or other qualified member of the technical staff. These controls are consistent with those normally applied to operation in the startup range as defined in the SRs and ACTIONS of LCO 3.3.2.1, "Control Rod Block Instrumentation."
APPLICABILITY	Control rod testing, while in MODES 1 and 2, with THERMAL POWER greater than 10% RTP, is adequately controlled by the existing LCOs on power distribution limits and control rod block instrumentation. Control rod movement during these conditions is not restricted to prescribed sequences and can be performed within the constraints of LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," and LCO 3.3.2.1. With THERMAL POWER less than or equal to 10% RTP, the provisions of this Special Operations LCO are necessary to perform special tests that are not in conformance with the prescribed sequences of LCO 3.1.6. While in MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with

(continued)

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8

(continued)

B

BASES

BACKGROUND (continued)

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

The 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 abnormal operational transients. 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

GE critical power correlations are applicable for all critical power calculations at pressures ≥ 785 psig and core flows ≥ 10% of rated flow. For operation at low pressures or low flows, another basis is used, as follows:

> The pressure drop in the bypass region is essentially all elevation head with a value > 4.5 psi; therefore, the core pressure drop at low power and flows will always be > 4.5 psi. At power, the static head inside

(continued)

BASES (continued)

SAFETY LIMITS

The reactor core SLs are established to protect the integrity of the fuel clad barrier to the release of radioactive materials to the environs. SL 2.1.1.1 and SL 2.1.1.2 ensure that the core operates within the fuel design criteria. SL 2.1.1.3 ensures that the reactor vessel water level is greater than the top of the active irradiated fuel in order to prevent elevated clad temperatures and resultant clad perforations.

APPLICABILITY

SLs 2.1.1.1, 2.1.1.2, and 2.1.1.3 are applicable in all MODES.

SAFETY LIMIT VIOLATIONS

2.2.1

If any SL is violated, the NRC Operations Center must be notified within 1 hour, in accordance with 10 CFR 50.72 (Ref. 3).

2.2.2

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

2.2.3

If any SL is violated, the senior management of the nuclear plant and the utility shall be notified within 24 hours. The 24 hour period provides time for plant operators and staff to take the appropriate immediate action and assess the condition of the unit before reporting to the senior management.

(continued)

BASES

ACTIONS

A.1, A.2, A.3, and A.4 (continued)

another pair of "slow" control rods adjacent to one another. The description of "slow" control rods is provided in LCO 3.1.4, "Control Rod Scram Times." In addition, the associated control rod drive must be disarmed in 2 hours. The allowed Completion Time of 2 hours is acceptable, considering the reactor can still be shut down, assuming no additional control rods fail to insert, and provides a reasonable time to perform the Required Action in an orderly manner. The control rod must be isolated from both scram and normal insert and withdraw pressure. Isolating the control rod from scram and normal insert and withdraw pressure prevents damage to the CRDM. The control rod should be isolated from scram and normal insert and withdraw pressure, while maintaining cooling water to the CRD.

Monitoring of the insertion capability of each withdrawn control rod must also be performed within 24 hours from discovery of Condition A concurrent with THERMAL POWER greater than the low power setpoint (LPSP) of the RWM. SR 3.1.3.2 and SR 3.1.3.3 perform periodic tests of the control rod insertion capability of withdrawn control rods. Testing each withdrawn control rod ensures that a generic problem does not exist. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." The Required Action A.3 Completion Time only begins upon discovery of Condition A concurrent with THERMAL POWER greater than the actual LPSP of the RWM, since the notch insertions may not be compatible with the requirements of rod pattern control (LCO 3.1.6) and the RWM (LCO 3.3.2.1). The allowed Completion Time of 24 hours from discovery of Condition A concurrent with THERMAL POWER greater than the LPSP of the RWM provides a reasonable time to test the control rods, considering the potential for a need to reduce power to perform the tests.

To allow continued operation with a withdrawn control rod stuck, an evaluation of adequate SDM is also required within 72 hours. Should a DBA or transient require a shutdown, to preserve the single failure criterion, an additional control rod would have to be assumed to fail to insert when required. Therefore, the original SDM demonstration may not be valid. The SDM must therefore be evaluated (by measurement or analysis) with the stuck control rod at its stuck position and the highest worth OPERABLE control rod assumed to be fully withdrawn.

(continued)

BASES

ACTIONS

A.1, A.2, A.3, and A.4 (continued)

The allowed Completion Time of 72 hours to verify SDM is adequate, considering that with a single control rod stuck in a withdrawn position, the remaining OPERABLE control rods are capable of providing the required scram and shutdown reactivity. Failure to reach MODE 4 is only likely if an additional control rod adjacent to the stuck control rod also fails to insert during a required scram. Even with the postulated additional single failure of an adjacent control rod to insert, sufficient reactivity control remains to reach and maintain MODE 3 conditions (Ref. 5).

B.1

With two or more withdrawn control rods stuck, the plant must be brought to MODE 3 within 12 hours. The occurrence of more than one control rod stuck at a withdrawn position increases the probability that the reactor cannot be shut down if required. Insertion of all insertable control rods eliminates the possibility of an additional failure of a control rod to insert. 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.

C.1 and C.2

With one or more control rods inoperable for reasons other than being stuck in the withdrawn position, operation may continue, provided the control rods are fully inserted within 3 hours and disarmed (electrically or hydraulically) within 4 hours. Inserting a control rod ensures the shutdown and scram capabilities are not adversely affected. The control rod is disarmed to prevent inadvertent withdrawal during subsequent operations. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. The control rods can be electrically disarmed by disconnecting power from all four directional control valve solenoids. Required Action C.1 is modified by a Note, which allows the RWM to be bypassed if required to allow insertion of the inoperable control rods and continued operation. LCO 3.3.2.1 provides additional requirements when the RWM is bypassed to ensure compliance with the CRDA analysis.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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

D.1 and D.2

Out of sequence control rods may increase the potential reactivity worth of a dropped control rod during a CRDA. At ≤ 10% RTP, the generic banked position withdrawal sequence (BPWS) analysis (Ref. 5) requires inserted control rods not in compliance with BPWS to be separated by at least two OPERABLE control rods in all directions, including the diagonal. Therefore, if two or more inoperable control rods are not in compliance with BPWS and not separated by at least two OPERABLE control rods, action must be taken to restore compliance with BPWS or restore the control rods to OPERABLE status. Condition D is modified by a Note indicating that the Condition is not applicable when > 10% RTP, since the BPWS is not required to be followed under these conditions, as described in the Bases for LCO 3.1.6. The allowed Completion Time of 4 hours is acceptable, considering the low probability of a CRDA occurring.

E.1

If any Required Action and associated Completion Time of Condition A, C, or D are not met, or there are nine or more inoperable control rods, 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. This ensures all insertable control rods are inserted and places the reactor in a condition that does not require the active function (i.e., scram) of the control rods. The number of control rods permitted to be inoperable when operating above 10% RTP (e.g., no CRDA considerations) could be more than the value specified, but the occurrence of a large number of

(continued)

BASES

ACTIONS

E.1 (continued)

inoperable control rods could be indicative of a generic problem, and investigation and resolution of the potential problem should be undertaken. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

The position of each control rod must be determined to ensure adequate information on control rod position is available to the operator for determining control rod OPERABILITY and controlling rod patterns. Control rod position may be determined by the use of OPERABLE position indicators, by moving control rods to a position with an OPERABLE indicator, or by the use of other appropriate methods. The 24 hour Frequency of this SR is based on operating experience related to expected changes in control rod position and the availability of control rod position indications in the control room.

SR 3.1.3.2 and SR 3.1.3.3

Control rod insertion capability is demonstrated by inserting each partially or fully withdrawn control rod at least one notch and observing that the control rod moves. The control rod may then be returned to its original position. This ensures the control rod is not stuck and is free to insert on a scram signal. These Surveillances are not required when THERMAL POWER is less than or equal to the actual LPSP of the RWM, since the notch insertions may not be compatible with the requirements of the Banked Position Withdrawal Sequence (BPWS) (LCO 3.1.6) and the RWM (LCO 3.3.2.1). The 7 day Frequency of SR 3.1.3.2 is based on operating experience related to the changes in CRD performance and the ease of performing notch testing for fully withdrawn control rods. Partially withdrawn control rods are tested at a 31 day Frequency, based on the potential power reduction required to allow the control rod movement and considering the large testing sample of SR 3.1.3.2. Furthermore, the 31 day Frequency takes into account operating experience related to changes in CRD performance. At any time, if a control rod is immovable, a

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.3.2 and SR 3.1.3.3 (continued)

determination of that control rod's trippability (OPERABILITY) must be made and appropriate action taken. For example, the unavailability of the Reactor Manual Control System does not affect the OPERABILITY of the control rods, provided SR 3.1.3.2 and SR 3.1.3.3 are current in accordance with SR 3.0.2.

SR 3.1.3.4

Verifying that the scram time for each control rod to notch position 06 is ≤ 7 seconds provides reasonable assurance that the control rod will insert when required during a DBA or transient, thereby completing its shutdown function. This SR is performed in conjunction with the control rod scram time testing of SR 3.1.4.1, SR 3.1.4.2, SR 3.1.4.3, and SR 3.1.4.4. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and the functional testing of SDV vent and drain valves in LCO 3.1.8, "Scram Discharge Volume (SDV) Vent and Drain Valves," overlap this Surveillance to provide complete testing of the assumed safety function. The associated Frequencies are acceptable, considering the more frequent testing performed to demonstrate other aspects of control rod OPERABILITY and operating experience, which shows scram times do not significantly change over an operating cycle.

SR 3.1.3.5

Coupling verification is performed to ensure the control rod is connected to the CRDM and will perform its intended function when necessary. The Surveillance requires verifying a control rod does not go to the withdrawn overtravel position. The overtravel position feature provides a positive check on the coupling integrity since only an uncoupled CRD can reach the overtravel position. The verification is required to be performed any time a control rod is withdrawn to the "full out" position (notch position 48) or prior to declaring the control rod OPERABLE after work on the control rod or CRD System that could affect coupling (CRD changeout and blade replacement or complete cell disassembly, i.e., guide tube removal). This includes control rods inserted one notch and then returned

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.3.5 (continued)

to the "full out" position during the performance of SR 3.1.3.2. This Frequency is acceptable, considering the low probability that a control rod will become uncoupled when it is not being moved and operating experience related to uncoupling events.

REFERENCES

1. UFSAR, Sections 1.5.1.1 and 1.5.2.2.
2. UFSAR, Section 14.6.2.
3. UFSAR, Appendix K, Section VI.
4. UFSAR, Chapter 14.
5. NEDO-21231, "Banked Position Withdrawal Sequence," Section 7.2, January 1977.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.8 Scram Discharge Volume (SDV) Vent and Drain Valves

BASES

BACKGROUND

The SDV vent and drain valves are normally open and discharge any accumulated water in the SDV to ensure that sufficient volume is available at all times to allow a complete scram. During a scram, the SDV vent and drain valves close to contain reactor water. As discussed in Reference 1, the SDV vent and drain valves need not be considered primary containment isolation valves (PCIVs) for the Scram Discharge System. (However, at PBAPS, these valves are considered PCIVs.) The SDV is a volume of header piping that connects to each hydraulic control unit (HCU) and drains into an instrument volume. There are two SDVs (headers) and a common instrument volume that receives all of the control rod drive (CRD) discharges. The instrument volume is connected to a common drain line with two valves in series. Each header is connected to a common vent line with two valves in series for a total of four vent valves. The header piping is sized to receive and contain all the water discharged by the CRDs during a scram. The design and functions of the SDV are described in Reference 2.

APPLICABLE SAFETY ANALYSES

The Design Basis Accident and transient analyses assume all of the control rods are capable of scramming. The acceptance criteria for the SDV vent and drain valves are that they operate automatically to close during scram to limit the amount of reactor coolant discharged so that adequate core cooling is maintained and offsite doses remain within the limits of 10 CFR 100 (Ref. 3).

Isolation of the SDV can also be accomplished by manual closure of the SDV valves. Additionally, the discharge of reactor coolant to the SDV can be terminated by scram reset or closure of the HCU manual isolation valves. For a bounding leakage case, the offsite doses are well within the limits of 10 CFR 100 (Ref. 3), and adequate core cooling is maintained (Ref. 1). The SDV vent and drain valves allow continuous drainage of the SDV during normal plant operation to ensure that 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 in the

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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 (Refs. 6, 7, 8, and 9). Flow dependent MCPR limits are determined by steady state thermal hydraulic methods with key physics response inputs benchmarked using the three dimensional BWR simulator code (Ref. 10) to analyze slow flow runout transients. The operating limit is dependent on the maximum core flow limiter setting in the Recirculation Flow Control System. Power dependent MCPR limits ($MCPR_p$) are determined mainly by the one dimensional transient code (Ref. 11). 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 scrams are bypassed, high and low flow $MCPR_p$ operating limits are provided for operating between 25% RTP and the previously mentioned bypass power level. In addition, unique MCPR limits have been established for the Lead Fuel Assemblies (LFAs) manufactured by Siemens Power Corporation (SPC) as discussed in Reference 12. The MCPR satisfies Criterion 2 of the NRC Policy Statement.
LCO	The MCPR operating limits specified in the COLR are the result of the Design Basis Accident (DBA) and transient analysis. The operating limit MCPR is 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 minimum 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 expected at 25% RTP is > 3.5. Studies of the variation of limiting transient behavior have been performed over the range of power and

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	includes allowances for short term transient operation above the operating limit to account for abnormal operational transients, plus an allowance for densification power spiking. The LHGR satisfies Criterion 2 of the NRC Policy Statement.
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	<u>A.1</u> 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. <u>B.1</u> 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 is 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

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.13 (continued)

If any bypass channel's setpoint is nonconservative (i.e., the Functions are bypassed at ≥ 30% RTP, either due to open main turbine bypass valve(s) or other reasons), then the affected Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel is considered OPERABLE.

The Frequency of 24 months is based on engineering judgment and reliability of the components.

SR 3.3.1.1.17

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional testing of control rods (LCO 3.1.3), and SDV vent and drain valves (LCO 3.1.8), 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 will pass the Surveillance when performed at the 24 month Frequency.

SR 3.3.1.1.18

This SR ensures that the individual channel response times are maintained less than or equal to the original design value. The RPS RESPONSE TIME acceptance criterion is included in Reference 11.

B

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.18 (continued)

RPS RESPONSE TIME tests are conducted on a 24 month Frequency. The 24 month Frequency is consistent with the PBAPS 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 occurrences.

REFERENCES

1. UFSAR, Section 7.2.
2. UFSAR, Section Chapter 14.
3. NEDO-23842, "Continuous Control Rod Withdrawal in the Startup Range," April 18, 1978.
4. NEDC-32183P, "Power Rerate Safety Analysis Report for Peach Bottom 2 & 3," dated May 1993.
5. UFSAR, Section 14.6.2.
6. UFSAR, Section 14.5.4.
7. UFSAR, Section 14.5.1.
8. P. Check (NRC) letter to G. Lainas (NRC), "BWR Scram Discharge System Safety Evaluation," December 1, 1980.
9. NEDO-30851-P-A , "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.
10. MDE-87-0485-1, "Technical Specification Improvement Analysis for the Reactor Protection System for Peach Bottom Atomic Power Station Units 2 and 3," October 1987.
11. UFSAR, Section 7.2.3.9.

BASES

ACTIONS

A.1 (continued)

automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

If a channel has not been restored to OPERABLE status in 30 days, this Required Action specifies initiation of action 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 action is appropriate in lieu of a shutdown requirement, since alternative actions are identified before loss of functional capability, and given the likelihood of plant conditions that would require information provided by this instrumentation.

C.1

When one or more Functions have two required channels that are inoperable (i.e., two channels inoperable in the same Function), 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.

(continued)

BASES

ACTIONS (continued)

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.

E.1

For the majority of Functions in Table 3.3.3.1-1, if the Required Action and associated Completion Time of Condition C is not met, the plant must be brought to a MODE in which the LCO not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

F.1

Since alternate means of monitoring drywell high range 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

parameter exceeds the setpoint, the associated device (e.g., internal relay contact) changes state. The Allowable Values are derived from the limiting values of the process parameters obtained from the safety analysis and corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, and instrument drift are accounted for.

The specific Applicable Safety Analyses, LCO, and Applicability discussions for Unit 3 LOP instrumentation are listed below on a Function by Function basis.

In addition, since some equipment required by Unit 3 is powered from Unit 2 sources, the Unit 2 LOP instrumentation supporting the required sources must also be OPERABLE. The OPERABILITY requirements for the Unit 2 LOP instrumentation is the same as described in this section, except Function 4 (4 kV Emergency Bus Undervoltage, Degraded Voltage LOCA) is not required to be OPERABLE, since this Function is related to a LOCA on Unit 2 only. The Unit 2 instrumentation is listed in Unit 2 Table 3.3.8.1-1.

1. 4 kV Emergency Bus Undervoltage (Loss of Voltage)

When both offsite sources are lost, a loss of voltage condition on a 4 kV emergency bus indicates that the respective emergency bus 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. This ensures that adequate power will be available to the required equipment.

The single channel of 4 kV Emergency Bus Undervoltage (Loss of Voltage) Function per associated emergency bus is only required to be OPERABLE when the associated DG and offsite circuit are required to be OPERABLE. This ensures no single instrument failure can preclude the start of three of four DGs. (One channel inputs to each of the four DGs.) Refer to LCO 3.8.1, "AC Sources—Operating," and 3.8.2, "AC Sources—Shutdown," for Applicability Bases for the DGs.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2., 3., 4., 5. 4 kV Emergency Bus Undervoltage (Degraded Voltage) (continued)

Two channels (one channel per source) of 4 kV Emergency Bus Undervoltage (Degraded Voltage) per Function (Functions 2, 3, 4, and 5) per associated bus are only required to be OPERABLE when the associated DG and offsite circuit are required to be OPERABLE. This ensures no single instrument failure can preclude the start of three of four DGs (each logic inputs to each of the four DGs). Refer to LCO 3.8.1 and LCO 3.8.2 for Applicability Bases for the DGs.

ACTIONS

A Note has been provided (Note 1) 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.

A.1

Pursuant to LCO 3.0.6, the AC Sources—Operating ACTIONS would not have to be entered even if the LOP instrumentation inoperability resulted in an inoperable offsite circuit. Therefore, the Required Action of Condition A is modified by a Note to indicate that when performance of a Required Action results in the inoperability of an offsite circuit, Actions for LCO 3.8.1, "AC Sources—Operating," must be immediately entered. A Unit 3 offsite circuit is considered to be inoperable if it is not supplying or not capable of supplying (due to loss of autotransfer capability) at least three Unit 3 4 kV emergency buses when the other offsite circuit is providing power or capable of supplying power to all four Unit 3 4 kV emergency buses. A Unit 3 offsite circuit is also considered to be inoperable if the Unit 3

(continued)

BASES

ACTIONS

A.1 (continued)

4 kV emergency buses being powered or capable of being powered from the two offsite circuits are all the same when at least one of the two circuits does not provide power or is not capable of supplying power to all four Unit 3 4 kV emergency buses. Inoperability of a Unit 2 offsite circuit is the same as described for a Unit 3 offsite circuit, except that the circuit path is to the Unit 2 4 kV emergency buses required to be OPERABLE by LCO 3.8.7, "Distribution Systems - Operating." The Note allows Condition A to provide requirements for the loss of a LOP instrumentation channel without regard to whether an offsite circuit is rendered inoperable. LCO 3.8.1 provides appropriate restriction for an inoperable offsite circuit.

Required Action A.1 is applicable when one 4 kV emergency bus has one or two required Function 3 (Degraded Voltage High Setting) channels inoperable or when one 4 kV emergency bus has one or two required Function 5 (Degraded Voltage Non-LOCA) channels inoperable. In this Condition, the affected Function may not be capable of performing its intended function automatically for these buses. However, the operators would still receive indication in the control room of a degraded voltage condition on the unaffected buses and a manual transfer of the affected bus power supply to the alternate source could be made without damaging plant equipment. Therefore, Required Action A.1 allows 14 days to restore the inoperable channel(s) to OPERABLE status or place the inoperable channel(s) in trip. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore design trip capability to the LOP instrumentation, and allow operation to continue. Alternatively, 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 DG initiation), Condition D must be entered and its Required Action taken.

The 14 day Completion Time is intended to allow time to restore the channel(s) to OPERABLE status. The Completion Time takes into consideration the diversity of the Degraded Voltage Functions, the capabilities of the remaining OPERABLE LOP Instrumentation Functions on the affected 4 kV emergency bus and on the other 4 kV emergency buses (only one 4 kV emergency bus is affected by the inoperable channels), the fact that the Degraded Voltage High Setting

(continued)

BASES

ACTIONS

A.1 (continued)

and Degraded Voltage Non-LOCA Functions provide only a marginal increase in the protection provided by the voltage monitoring scheme, the low probability of the grid operating in the voltage band protected by these Functions, and the ability of the operators to perform the Functions manually.

B.1

Pursuant to LCO 3.0.6, the AC Sources—Operating ACTIONS would not have to be entered even if the LOP instrumentation inoperability resulted in an inoperable offsite circuit. Therefore, the Required Action of Condition B is modified by a Note to indicate that when performance of a Required Action results in the inoperability of an offsite circuit, Actions for LCO 3.8.1, "AC Sources—Operating," must be immediately entered. A Unit 3 offsite circuit is considered to be inoperable if it is not supplying or not capable of supplying (due to loss of autotransfer capability) at least three Unit 3 4 kV emergency buses when the other offsite circuit is providing power or capable of supplying power to all four Unit 3 4 kV emergency buses. A Unit 3 offsite circuit is also considered to be inoperable if the Unit 3 4 kV emergency buses being powered or capable of being powered from the two offsite circuits are all the same when at least one of the two circuits does not provide power or is not capable of supplying power to all four Unit 3 4 kV emergency buses. Inoperability of a Unit 2 offsite circuit is the same as described for a Unit 3 offsite circuit, except that the circuit path is to the Unit 2 4 kV emergency buses required to be OPERABLE by LCO 3.8.7, "Distribution Systems - Operating." This allows Condition B to provide requirements for the loss of a LOP instrumentation channel without regard to whether an offsite circuit is rendered inoperable. LCO 3.8.1 provides appropriate restriction for an inoperable offsite circuit.

Required Action B.1 is applicable when two 4 kV emergency buses have one required Function 3 (Degraded Voltage High Setting) channel inoperable, or when two 4 kV emergency buses have one required Function 5 (Degraded Voltage Non-LOCA) channel inoperable, or when one 4 kV emergency bus has one required Function 3 channel inoperable and a different 4 kV emergency bus has one required Function 5 channel inoperable. In this Condition, the affected Function may

(continued)

BASES

ACTIONS

B.1 (continued)

not be capable of performing its intended function automatically for these buses. However, the operators would still receive indication in the control room of a degraded voltage condition on the unaffected buses and a manual transfer of the affected bus power supply to the alternate source could be made without damaging plant equipment. Therefore, Required Action B.1 allows 24 hours to restore the inoperable channels to OPERABLE status or place the inoperable channels in trip. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore design trip capability to the LOP instrumentation, and allow operation to continue. Alternatively, 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 DG initiation), Condition D must be entered and its Required Action taken.

The 24 hour Completion Time is intended to allow time to restore the channel(s) to OPERABLE status. The Completion Time takes into consideration the diversity of the Degraded Voltage Functions, the capabilities of the remaining OPERABLE LOP Instrumentation Functions on the affected 4 kV emergency buses and on the other 4 kV emergency buses (only two 4 kV emergency buses are affected by the inoperable channels), the fact that the Degraded Voltage High Setting and Degraded Voltage Non-LOCA Functions provide only a marginal increase in the protection provided by the voltage monitoring scheme, the low probability of the grid operating in the voltage band protected by these Functions, and the ability of the operators to perform the Functions manually.

C.1

Pursuant to LCO 3.0.6, the AC Sources—Operating ACTIONS would not have to be entered even if the LOP Instrumentation inoperability resulted in an inoperable offsite circuit. Therefore, the Required Action of Condition C is modified by a Note to indicate that when performance of the Required Action results in the inoperability of an offsite circuit, Actions for LCO 3.8.1, "AC Sources—Operating," must be immediately entered. A Unit 3 offsite circuit is considered to be inoperable if it is not supplying or not capable of supplying (due to loss of autotransfer capability) at least three Unit 3 4 kV emergency buses when

(continued)

BASES

ACTIONS

C.1 (continued)

the other offsite circuit is providing power or capable of supplying power to all four Unit 3 4 kV emergency buses. A Unit 3 offsite circuit is also considered to be inoperable if the Unit 3 4 kV emergency buses being powered or capable of being powered from the two offsite circuits are all the same when at least one of the two circuits does not provide power or is not capable of supplying power to all four Unit 3 4 kV emergency buses. Inoperability of a Unit 2 offsite circuit is the same as described for a Unit 3 offsite circuit, except that the circuit path is to the Unit 2 4 kV emergency buses required to be OPERABLE by LCO 3.8.7, "Distribution Systems - Operating." The Note allows Condition C to provide requirements for the loss of a LOP instrumentation channel without regard to whether an offsite circuit is rendered inoperable. LCO 3.8.1 provides appropriate restriction for an inoperable offsite circuit.

Required Action C.1 is applicable when one or more 4 kV emergency buses have one or more required Function 1, 2, or 4 (the Loss of Voltage, the Degraded Voltage Low Setting, and the Degraded Voltage LOCA Functions, respectively) channels inoperable, or when one 4 kV emergency bus has one required Function 3 (Degraded Voltage High Setting) channel and one required Function 5 (Degraded Voltage Non-LOCA) channel inoperable, or when any combination of three or more required Function 3 and Function 5 channels are inoperable. In this Condition, the affected Function may not be capable of performing the intended function and the potential consequences associated with the inoperable channel(s) are greater than those resulting from Condition A or Condition B. 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 design trip capability to the LOP instrumentation, 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 DG initiation), Condition D must be entered and its Required Action taken. B

(continued)

BASES

ACTIONS

C.1 (continued)

The Completion Time is based on the potential consequences associated with the inoperable channel(s) and is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

B

D.1

If any Required Action and associated Completion Time are not met, the associated Function is not capable of performing the intended function. Therefore, the associated DG(s) is declared inoperable immediately. This requires entry into applicable Conditions and Required Actions of LCO 3.8.1 and LCO 3.8.2, which provide appropriate actions for the inoperable DG(s).

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each Unit 3 LOP instrumentation Function are located in the SRs column of Table 3.3.8.1-1. SR 3.3.8.1.5 is applicable only to the Unit 2 LOP instrumentation.

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 2 hours provided: (a) for Function 1, the associated Function maintains initiation capability for three DGs; and (b) for Functions 2, 3, 4, 5, the associated Function maintains undervoltage transfer capability for three 4 kV emergency buses. The loss of function for one DG or undervoltage transfer capability for the 4 kV emergency bus for this short period is appropriate since only three of four DGs are required to start within the required times and because there is no appreciable impact on risk. Also, upon completion of the Surveillance, or expiration of the 2 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.1.1 and SR 3.3.8.1.3

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.

The Frequency of 31 days is based on operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one degraded voltage channel of a given Function in any 31 day interval is a rare event. The Frequency of 24 months is based on operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of the loss of voltage channel in any 24 month interval is a rare event.

SR 3.3.8.1.2

A CHANNEL CALIBRATION is a complete check of the relay circuitry and associated time delay relays. 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 assumptions of the current plant specific setpoint methodology.

The 18 month Frequency for the degraded voltage Functions is based upon the assumption 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.1.5

With the exception of this Surveillance, all other Surveillances of this Specification (SR 3.3.8.1.1 through SR 3.3.8.1.4) are applied only to the Unit 3 LOP instrumentation. This Surveillance is provided to direct that the appropriate Surveillances for the required Unit 2 LOP instrumentation are governed by the Unit 2 Technical Specifications. Performance of the applicable Unit 2 Surveillances will satisfy Unit 2 requirements, as well as satisfying this Unit 3 Surveillance Requirement.

The Frequency required by the applicable Unit 2 SR also governs performance of that SR for Unit 3.

REFERENCES

1. UFSAR, Chapter 14.

B 3.3 INSTRUMENTATION

B 3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

BASES

BACKGROUND

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 of the essential safety circuits. Some of the essential equipment powered from the RPS buses includes the RPS logic and scram solenoids.

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 in series 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, 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 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 if in service. Each of these circuit breakers has an associated independent set

(continued)

BASES

BACKGROUND (continued)

of Class 1E overvoltage, undervoltage, underfrequency relays, time delay relays (MG sets only), and sensing logic. Together, a circuit breaker, its associated relays, and sensing logic constitute an electric power monitoring assembly. If the output of the MG set or alternate power supply exceeds 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

The 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 components that receive power from the RPS buses, by acting to disconnect the RPS from the power supply under specified conditions that could damage the RPS equipment.

RPS electric power monitoring satisfies Criterion 3 of the NRC Policy Statement.

LCO

The OPERABILITY of each RPS electric power monitoring assembly is dependent on 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. 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 components. Each inservice electric power monitoring assembly's trip logic setpoints are required to be within the specified Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each RPS electric power monitoring assembly trip logic (refer to SR 3.3.8.2.2). Trip setpoints are specified in design documents. The trip setpoints are selected based on engineering judgement and operational experience to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setting less conservative than the trip setpoint, but within its Allowable Value, is

(continued)

BASES

LCO (continued)

acceptable. A channel is inoperable if its actual trip setting 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 changes state.

The overvoltage Allowable Values for the RPS electrical power monitoring assembly trip logic are derived from vendor specified voltage requirements.

The underfrequency Allowable Values for the RPS electrical power monitoring assembly trip logic are based on tests performed at Peach Bottom which concluded that the lowest frequency which would be reached was 54.4 Hz in 7.5 to 11.0 seconds depending load. Bench tests were also performed on RPS components (HFA relays, scram contactors, and scram solenoid valves) under conditions more severe than those expected in the plant (53 Hz during 11.0 and 15.0 second intervals). Examination of these components concluded that the components functioned correctly under these conditions.

The undervoltage Allowable Values for the RPS electrical power monitoring assembly trip logic were confirmed to be acceptable through testing. Testing has shown the scram pilot solenoid valves can be subjected to voltages below 95 volts with no degradation in their ability to perform their safety function. It was concluded the RPS logic relays and scram contactors will not be adversely affected by voltage below 95 volts since these components will dropout under these voltage conditions thereby satisfying their safety function.

APPLICABILITY

The operation of the RPS electric power monitoring assemblies is essential to disconnect the RPS 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 components are required to be OPERABLE. This results in the RPS Electric Power Monitoring System OPERABILITY being required in MODES 1 and 2; and in MODES 3, 4, and 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.

(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 components under degraded voltage or frequency conditions. However, the reliability and redundancy of the RPS Electric Power Monitoring System is reduced, and only a limited time (72 hours) is allowed to restore the inoperable assembly to OPERABLE status. If the inoperable assembly cannot be restored to OPERABLE status, the associated power supply(s) must be removed from service (Required Action A.1). This places the RPS bus in a safe condition. An alternate power supply with OPERABLE powering 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.

Alternately, if it is not desired to remove the power supply 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 supply(s) must be removed from service within 1 hour (Required Action B.1). An alternate power supply with OPERABLE assemblies may then be used to power one RPS bus.

(continued)

BASES

ACTIONS

B.1 (continued)

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 or 2, 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. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 3, 4, or 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 D.1 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.1

A CHANNEL FUNCTIONAL TEST is performed on each overvoltage, undervoltage, and underfrequency channel to ensure that the entire channel will perform the intended function. Any setpoint adjustment shall be consistent with design documents.

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). As such, this Surveillance is required to be performed when the unit is in MODE 4 for ≥ 24 hours and the test has not been performed in the previous 184 days. This Surveillance must be performed prior to entering MODE 2 or 3 from MODE 4 if a performance is required. The 24 hours is intended to indicate an outage of sufficient duration to allow for scheduling and proper performance of the Surveillance.

The 184 day Frequency and the Note in the Surveillance are based on guidance provided in Generic Letter 91-09 (Ref. 2).

SR 3.3.8.2.2 and SR 3.3.8.2.3

CHANNEL CALIBRATION is a complete check of the relay circuitry and applicable time delay relays. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted between successive calibrations consistent with the plant design documents.

The Frequency is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.8.2.4

Performance of a system functional test demonstrates that, with a required system actuation (simulated or actual) signal, the logic of the system will automatically trip open the associated power monitoring assembly. Only one signal

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.4 (continued)

per power monitoring assembly is required to be tested. This Surveillance overlaps with the CHANNEL CALIBRATION to provide complete testing of the safety function. The system functional test of the Class 1E circuit breakers is included as part of this test to provide complete testing of the safety function. If the breakers are incapable of operating, the associated electric power monitoring assembly would be inoperable.

The 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 will pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. UFSAR, Section 7.2.3.2.
2. NRC Generic Letter 91-09, "Modification of Surveillance Interval for the Electrical Protective Assemblies in Power Supplies for the Reactor Protection System."

(continued)

B

(continued)

TABLE OF CONTENTS (continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Plant specific LOCA and average power range monitor/rod block monitor Technical Specification/maximum extended load line limit analyses have been performed assuming only one operating recirculation loop. These analyses demonstrate 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 (Refs. 2, 3, and 4).

The transient analyses of Chapter 14 of the UFSAR have also been performed for single recirculation loop operation (Ref. 5) 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 (RPS) 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 MCPR limits and APLHGR limits (power-dependent APLHGR multipliers, $MAPFAC_p$, and flow-dependent APLHGR multipliers, $MAPFAC_f$) for single loop operation are specified in the COLR. The APRM Flow Biased High Scram Allowable Value is in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation."

Safety analyses performed for UFSAR Chapter 14 implicitly assume core conditions are stable. However, at the high power/low flow corner of the power/flow map, an increased probability for limit cycle oscillations exists (Ref. 6) depending on combinations of operating conditions (e.g., power shape, bundle power, and bundle flow). Generic evaluations indicate that when regional power oscillations become detectable on the APRMs, the safety margin may be insufficient under some operating conditions to ensure actions taken to respond to the APRMs signals would prevent violation of the MCPR Safety Limit (Ref. 7). NRC Generic Letter 86-02 (Ref. 8) addressed stability calculation methodology and stated that due to uncertainties, 10 CFR 50, Appendix A, General Design Criteria (GDC) 10 and 12 could not be met using analytic procedures on a BWR 4 design. However, Reference 8 concluded that operating limitations which provide for the detection (by monitoring neutron flux noise levels) and suppression of flux oscillations in operating regions of potential instability consistent with

(continued)

BASES

LCO (continued)

in operation, modifications to the required APLHGR limits (power- and flow-dependent APLHGR multipliers, $MAPFAC_P$ and $MAPFAC_F$, respectively of LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"), MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and APRM Flow Biased High Scram Allowable Value (LCO 3.3.1.1) must be applied to allow continued operation consistent with the assumptions of References 5 and 6.

The LCO is modified by a Note which allows up to 12 hours before having to put in effect the required modifications to required limits after a change in the reactor operating conditions from two recirculation loops operating to single recirculation loop operation. If the required limits are not in compliance with the applicable requirements at the end of this period, the associated equipment must be declared inoperable or the limits "not satisfied," and the ACTIONS required by nonconformance with the applicable specifications implemented. This time is provided due to the need to stabilize operation with one recirculation loop, including the procedural steps necessary to limit flow in the operating loop, limit total THERMAL POWER, monitor for excessive APRM and local power range monitor (LPRM) neutron flux noise levels; and the complexity and detail required to fully implement and confirm the required limit modifications.

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

With one or two recirculation loops in operation with core flow as a function of THERMAL POWER in the "Restricted" Region of Figure 3.4.1-1, the plant is operating in a region where the potential for thermal hydraulic instability exists. In order to assure sufficient margin is provided for operator response to detect and suppress potential limit cycle oscillations, APRM and local power range monitor

(continued)

BASES

ACTIONS

A.1 (continued)

(LPRM) neutron flux noise levels must be periodically monitored and verified to be ≤ 4% and ≤ 3 times baseline noise levels. Detector levels A and C of one LPRM string per core quadrant plus detectors A and C of one LPRM string in the center of the core shall be monitored. A minimum of four APRMs shall also be monitored. The Completion Times of this verification (within 1 hour and once per 8 hours thereafter and within 1 hour after completion of any THERMAL POWER increase ≥ 5% RATED THERMAL POWER) are acceptable for ensuring potential limit cycle oscillations are detected to allow operator response to suppress the oscillation. These Completion Times were developed considering the operator's inherent knowledge of reactor status and sensitivity to potential thermal hydraulic instabilities when operating in this condition.

B.1

With the Required Action and associated Completion Time of Condition A not met, sufficient margin may not be available for operator response to suppress potential limit cycle oscillations since APRM or LPRM neutron flux noise levels may be > 4% and > 3 times baseline noise levels. As a result, action must be immediately initiated to restore noise levels to within required limits. The 2 hour Completion Time for restoring APRM and LPRM neutron flux noise levels to within required limits is acceptable because it minimizes risk while allowing time for restoration before subjecting the plant to transients associated with shutdown.

C.1 and C.2

With one recirculation loop in operation with core flow ≤ 39% of rated core flow and THERMAL POWER in the "Restricted" Region of Figure 3.4.1-1, an increased potential for thermal hydraulic instability exists. As a result, immediate action should be initiated to reduce THERMAL POWER to the "Unrestricted" Region of Figure 3.4.1-1 or increase core flow to > 39% of rated core flow. The

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

4 hour Completion Time provides a reasonable amount of time to complete the Required Action and is considered acceptable based on the frequent core monitoring by the operators (Required Action A.1) allowing potential limit cycle oscillations to be quickly detected.

D.1

With the requirements of the LCO not met for reasons other than Conditions A, B, C, and F, the recirculation loops must be restored to operation with matched flows within 24 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. The loop with the lower flow must be considered not in operation. (However, the flow rate of both loops shall be used for the purposes of determining if the THERMAL POWER and core flow combination is in the Unrestricted Region of Figure 3.4.1-1.) 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 and RPS setpoints, operation with only one recirculation loop would satisfy the requirements of the LCO and the initial conditions of the accident sequence.

The 24 hour Completion Time is 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.

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

(continued)

BASES

ACTIONS

D.1 (continued)

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.

E.1

With any Required Action and associated Completion Time of Condition B, C, or D 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 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.

F.1

With no recirculation loops in operation, the plant must be brought to a MODE in which the LCO does not apply. Action must be initiated immediately to reduce THERMAL POWER to be within the "Unrestricted" Region of Figure 3.4.1-1 to assure thermal hydraulic stability concerns are addressed. The plant is then required to be placed in MODE 3 in 6 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 is reasonable to reach MODE 3 considering the potential for thermal hydraulic instability in this condition.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

This SR ensures the recirculation loops are within the allowable limits for mismatch. At low core flow (i.e., < 71.75×10^6 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1 (continued)

can therefore be allowed when core flow is < 71.75 X 10^6 lbm/hr. The recirculation loop jet pump flow, as used in this Surveillance, is the summation of the flows from all of the jet pumps associated with a single recirculation loop.

The mismatch is measured in terms of core flow. (Rated core flow is 102.5 X 10^6 lbm/hr. The first limit is based on mismatch ≤ 10% of rated core flow when operating at < 70% of rated core flow. The second limit is based on mismatch ≤ 5% of rated core flow when operating at ≥ 70% of rated core flow.) If the flow mismatch exceeds the specified limits, the loop with the lower flow is considered not in operation. (However, for the purposes of performing SR 3.4.1.2, the flow rate of both loops shall be used.) The 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 Surveillance 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 reactor THERMAL POWER and core flow are within appropriate parameter limits to prevent uncontrolled power oscillations. At low recirculation flows and high reactor power, the reactor exhibits increased susceptibility to thermal hydraulic instability. Figure 3.4.1-1 is based on guidance provided in Reference 6, which is used to respond to operation in these conditions. The 24 hour Frequency is based on operating experience and the operators' inherent knowledge of reactor status, including significant changes in THERMAL POWER and core flow.

REFERENCES

1. UFSAR, Section 14.6.3.

2. NEDC-32163P, "PBAPS Units 2 and 3 SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," January 1993.

(continued)

BASES

REFERENCES (continued)

3. NEDC-32162P, "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Peach Bottom Atomic Power Station Unit 2 and 3," Revision 1, February 1993.

4. NEDC-32427P, "Peach Bottom Atomic Power Station Unit 3 Cycle 10 ARTS Thermal Limits Analyses," December 1994.

5. NEDO-24229-1, "PBAPS Units 2 and 3 Single-Loop Operation," May 1980.

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

7. NRC Bulletin 88-07, "Power Oscillations in Boiling Water Reactors (BWRs)," Supplement 1, December 30, 1988.

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

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 Jet Pumps

BASES

BACKGROUND

The Reactor Coolant Recirculation 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 reactor vessel internals and in conjunction with the Reactor Coolant Recirculation System 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 ten 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 implicit 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.

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 Reactor Coolant Recirculation 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 Reactor Coolant Recirculation System (LCO 3.4.1).

In MODES 3, 4, and 5, the Reactor Coolant Recirculation 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 of reflooding 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 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

This SR is designed to detect significant degradation in jet pump performance that precedes jet pump failure (Ref. 2). 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 the 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. 2 and 3). Each recirculation loop must satisfy one of the performance criteria provided. 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 baselining 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 (pump flow and 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 indicates a plug, flow restriction, loss in pump hydraulic performance, leakage, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, the pump flow and loop flow versus pump speed relationship must be verified.

Individual jet pumps in a recirculation loop normally 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1 (continued)

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. This may be indicated by an increase in the relative flow for a jet pump that has experienced beam cracks.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system (Ref. 2). Normal flow ranges and established jet pump flow and differential pressure patterns are established by plotting historical data as discussed in Reference 2.

The 24 hour Frequency has been shown by operating experience to be timely for detecting jet pump degradation and is consistent with the Surveillance 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% of 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. UFSAR, Section 14.6.3.

2. GE Service Information Letter No. 330, "Jet Pump Beam Cracks," June 9, 1980.

3. 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) and Safety Valves (SVs)

BASES

BACKGROUND

The ASME Boiler and Pressure Vessel Code 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 SRVs and SVs 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 and SVs are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. The SRVs can actuate by either of two modes: the safety mode or the depressurization mode. In the safety mode, the pilot disc opens when steam pressure at the valve inlet expands the bellows to the extent that the hydraulic seating force on the pilot disc is reduced to zero. Opening of the pilot stage allows a pressure differential to develop across the second stage disc which opens the second stage disc, thus venting the chamber over the main valve piston. This causes a pressure differential across the main valve piston which opens the main valve. The SVs are spring loaded valves that actuate when steam pressure at the inlet overcomes the spring force holding the valve disc closed. This satisfies the Code requirement.

Each of the 11 SRVs discharge steam through a discharge line to a point below the minimum water level in the suppression pool. The two SVs discharge steam directly to the drywell. In the depressurization mode, the SRV is opened by a pneumatic actuator which opens the second stage disc. The main valve then opens as described above for the safety mode. The depressurization mode provides controlled depressurization of the reactor coolant pressure boundary. All 11 of the SRVs function in the safety mode and have the capability to operate in the depressurization mode via manual actuation from the control room. Five of the SRVs are allocated to the Automatic Depressurization System (ADS). The ADS requirements are specified in LCO 3.5.1, "ECCS—Operating."

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressurization 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). For the purpose of the analyses, 11 SRVs and SVs are assumed to operate in the safety mode. The analysis results demonstrate that the design SRV and SV capacity is capable of maintaining reactor pressure below the ASME Code limit 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 Design Basis Event.

From an overpressure standpoint, the design basis events are bounded by the MSIV closure with flux scram event described above. Reference 2 discusses additional events that are expected to actuate the SRVs and SVs.

SRVs and SVs satisfy Criterion 3 of the NRC Policy Statement.

LCO

The safety function of any combination of 11 SRVs and SVs are required to be OPERABLE to satisfy the assumptions of the safety analysis (Refs. 1 and 2). Regarding the SRVs, the requirements of this LCO are applicable only to their capability to mechanically open to relieve excess pressure when the lift setpoint is exceeded (safety mode).

The SRV and SV setpoints are established to ensure that the ASME Code limit on peak reactor pressure is satisfied. The ASME Code specifications require the lowest safety valve setpoint to be at or below vessel design pressure (1250 psig) and the highest safety valve to be set so that the total accumulated pressure does not exceed 110% of the design pressure for overpressurization conditions. The transient evaluations in the UFSAR are based on these setpoints, but also include the additional uncertainties of + 1% of the nominal setpoint 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.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, all required SRVs and SVs must be OPERABLE, since considerable energy may be in the reactor core and the limiting design basis transients are assumed to occur in these MODES. The SRVs and SVs may be required to provide pressure relief to discharge energy from the core until such time that the Residual Heat Removal (RHR) System is capable of dissipating the core heat.

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 and SV function is not needed during these conditions.

ACTIONS

A.1 and A.2

With less than the minimum number of required SRVs or SVs OPERABLE, a transient may result in the violation of the ASME Code limit on reactor pressure. If the safety function of one or more required SRVs or SVs is 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 and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

This Surveillance requires that the required SRVs and SVs will open at the pressures assumed in the safety analyses of References 1 and 2. The demonstration of the SRV and SV safety lift settings must be performed during shutdown, since this is a bench test, to be done 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 and be verified with insulation installed simulating the in-plant condition. The SRV and SV setpoint is ± 1% for OPERABILITY.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 control valves or bypass valves, by a change in the measured steam flow, or by 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 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 greater than or equal to the Electro-Hydraulic Control (EHC) System minimum pressure set with EHC controlling pressure (EHC begins controlling pressure at a nominal 150 psig). Adequate steam flow is represented by at least 3 turbine bypass valves open. Plant startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME Code requirements, prior to valve installation. 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 is reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SR. If a 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 considered OPERABLE.

The 24 month Frequency is based on the need to perform the Surveillance under the conditions that apply just prior to or during a startup from a plant outage. Operating experience has shown that these components will pass the SR when performed at the 24 month Frequency, which is based on the refueling outage. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. NEDC-32183P, "Power Rerate Safety Analysis Report for Peach Bottom 2 & 3," May 1993.

2. UFSAR, Chapter 14.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 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 the UFSAR (Refs. 1, 2, and 3).

The safety significance of RCS LEAKAGE from the RCPB varies widely depending on the source, rate, and duration. Therefore, detection of LEAKAGE in the primary containment 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 that is detrimental to the safety of the facility or the public.

A limited amount of leakage inside primary containment is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected and isolated from the primary containment 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.

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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 that, 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 that leakage rates of hundreds of gallons per minute will precede crack instability.

The low limit on increase in unidentified LEAKAGE assumes a failure mechanism of intergranular stress corrosion cracking (IGSCC) in service sensitive type 304 and type 316 austenitic stainless steel 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.

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, since it is 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

The 5 gpm of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and drywell sump level 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 service sensitive 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 piping is very susceptible to IGSCC.

The 4 hour Completion Time is reasonable to properly reduce the LEAKAGE increase or verify the source before the reactor must be shut down without unduly jeopardizing plant safety.

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

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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 safety systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

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 3.4.5, "RCS Leakage Detection Instrumentation." Sump level and flow rate are typically monitored to determine actual LEAKAGE rates; however, any method may be used to quantify LEAKAGE within the guidelines of Reference 6. In conjunction with alarms and other administrative controls, a 4 hour Frequency for this Surveillance is appropriate for identifying LEAKAGE and for tracking required trends (Ref. 7).

REFERENCES

1. 10 CFR 50.2.
2. 10 CFR 50.55a(c).
3. UFSAR, Section 4.10.4.
4. GEAP-5620, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flaws," April 1968.
5. NUREG-75/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactors," October 1975.
6. Regulatory Guide 1.45, May 1973.
7. Generic Letter 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping," January 1988.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

UFSAR Safety Design Basis (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 leakage rates. The Bases for LCO 3.4.4, "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 level changes and drywell gaseous radioactivity levels. The primary means of quantifying LEAKAGE in the drywell is the drywell floor drain sump monitoring system.

The drywell floor drain sump 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.

An alternate to the drywell floor drain sump monitoring system is the drywell equipment drain sump monitoring system, but only if the drywell floor drain sump is overflowing. The drywell equipment drain sump collects not only all leakage not collected in the drywell floor drain sump, but also any overflow from the drywell floor drain sump. Therefore, if the drywell floor drain sump is

(continued)

BASES

BACKGROUND (continued)	overflowing to the drywell equipment drain sump, the drywell equipment drain sump monitoring system can be used to quantify LEAKAGE. In this condition, all LEAKAGE measured by the drywell equipment drain sump monitoring system is assumed to be unidentified LEAKAGE. The floor drain sump level indicators have switches that start and stop the sump pumps when required. If the sump fills to the high high level setpoint, an alarm sounds in the control room, indicating a LEAKAGE rate into the sump in excess of 50 gpm. A flow transmitter in the discharge line of the drywell floor drain sump pumps provides flow indication in the control room. The pumps can also be started from the control room. The primary containment air monitoring system continuously monitors the primary containment atmosphere for airborne 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 primary containment atmosphere gaseous radioactivity monitoring system is not capable of quantifying LEAKAGE rates, but is sensitive enough to indicate increased LEAKAGE rates of 1 gpm within 1 hour. Larger changes in LEAKAGE rates are detected in proportionally shorter times (Ref. 3).
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. 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.

(continued)

BASES (continued)

LCO

The drywell sump monitoring system is required to quantify the unidentified LEAKAGE from the RCS. Thus, for the system to be considered OPERABLE, the system must be capable of measuring reactor coolant leakage. This may be accomplished by use of the associated drywell sump flow integrator, flow recorder, or the pump curves and drywell sump pump out time. The system consists of a) the drywell floor drain sump monitoring system, or b) the drywell equipment drain sump monitoring system, but only when the drywell floor drain sump is overflowing. The other monitoring system provides 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 3.4.4. This Applicability is consistent with that for LCO 3.4.4.

ACTIONS

A.1

With the drywell sump monitoring system inoperable, no other form of sampling can provide the equivalent information to quantify leakage. However, the primary containment atmospheric radioactivity monitor will provide indication of changes in leakage.

With the drywell sump monitoring system inoperable, operation may continue for 24 hours. The 24 hour Completion Time is acceptable, based on operating experience, considering no other method to quantify leakage is available.

B.1 and B.2

With the gaseous primary containment atmospheric monitoring channel inoperable, grab samples of the primary containment atmosphere must be taken and analyzed for gaseous radioactivity to provide periodic leakage information. Provided a sample is obtained and analyzed once every 12 hours, the plant may be operated for up to 30 days to allow restoration of the required monitor.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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 the gaseous primary containment atmospheric monitoring channel is inoperable. This allowance is provided because other instrumentation is available to monitor RCS leakage.

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 MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to perform the actions 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

SR 3.4.5.1

This SR is for the performance of a CHANNEL CHECK of the required primary containment 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 3.4.5.2

This SR is for 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 3.4.5.3

This SR is for the performance of a CHANNEL CALIBRATION of required leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string.

The Frequency is 92 days and operating experience has proven this Frequency is acceptable.

REFERENCES

1. UFSAR, Section 4.10.2.
2. Regulatory Guide 1.45, May 1973.
3. UFSAR, Section 4.10.3.
4. GEAP-5620, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flaws," April 1968.
5. NUREG-75/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactors," October 1975.
6. UFSAR, Section 4.10.4.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Specific Activity

BASES

BACKGROUND

During circulation, the reactor coolant acquires radioactive materials due to release of fission products from fuel leaks into the reactor coolant and activation of corrosion products in the reactor coolant. These radioactive materials in the reactor 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 that 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 the 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 level is intended to limit the 2 hour radiation dose to an individual at the site boundary to well within the 10 CFR 100 limit.

APPLICABLE SAFETY ANALYSES

Analytical methods and assumptions involving radioactive material in the primary coolant are presented in the UFSAR (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 the dose guidelines of 10 CFR 100.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limits on specific activity are values from a parametric evaluation of typical site locations. These limits are 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.

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 well within 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) to be cleaned up with the normal processing systems.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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 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 once 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.

Alternatively, the plant can be placed in MODE 3 within 12 hours and in 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 placing the unit in MODES 3 and 4 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS	SR 3.4.6.1 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. 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, 1973. 2. UFSAR, Section 14.6.5.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 Residual Heat Removal (RHR) Shutdown Cooling System—Hot 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 reduce the temperature of the reactor coolant to ≤ 212°F. This decay heat removal is in preparation for performing refueling or maintenance operations, or for keeping the reactor in the Hot Shutdown condition.

The RHR System has two loops with each loop consisting of two motor driven pumps, two heat exchangers, and associated piping and valves. There are two RHR shutdown cooling subsystems per RHR System loop. Both loops have a common suction from the same recirculation loop. The four redundant, manually controlled shutdown cooling subsystems of the RHR System provide decay heat removal. 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 High Pressure Service Water (HPSW) System. Any one of the four RHR shutdown cooling subsystems can provide the required decay heat removal function.

APPLICABLE SAFETY ANALYSES

Decay heat removal by operation of 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.

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, a HPSW pump capable of providing cooling to the heat exchanger, and the associated piping and valves. The two subsystems have a common suction source and are allowed to have common discharge piping. Since piping is a passive component that

(continued)

BASES

LCO (continued)

is assumed not to fail, it is allowed to be common to both subsystems. 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 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 required 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 required 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 shutdown cooling isolation pressure (i.e., the actual pressure at which the RHR shutdown cooling isolation pressure setpoint clears) 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 shutdown cooling isolation 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 shutdown cooling isolation pressure is typically accomplished by condensing the steam in the main condenser.

(continued)

BASES

APPLICABILITY (continued)

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 3.4.8, "Residual Heat Removal (RHR) Shutdown Cooling System—Cold Shutdown"; LCO 3.9.7, "Residual Heat Removal (RHR)—High Water Level"; and LCO 3.9.8, "Residual Heat Removal (RHR)—Low Water Level."

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 required 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

(continued)

BASES

ACTIONS

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

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 required RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities.

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

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 permitted by LCO Note 1, reactor coolant circulation by the RHR shutdown cooling subsystem or 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

(continued)

BASES

ACTIONS

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

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 3.4.7.1

This Surveillance verifies that one required 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 setpoint 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

None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 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 ≤ 212°F. This decay heat removal is in preparation for performing refueling or maintenance operations, or for keeping the reactor in the Cold Shutdown condition.

The RHR System has two loops with each loop consisting of two motor driven pumps, two heat exchangers, and associated piping and valves. There are two RHR shutdown cooling subsystems per RHR System loop. Both loops have a common suction from the same recirculation loop. The four redundant, manually controlled shutdown cooling subsystems of the RHR System provide decay heat removal. 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 High Pressure Service Water (HPSW) System. Any one of the four RHR shutdown cooling subsystems can provide the requested decay heat removal function.

APPLICABLE SAFETY ANALYSES

Decay heat removal by operation of 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.

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, a HPSW pump capable of providing cooling to the heat exchanger, and the associated piping and valves. The two subsystems have a common suction source and are allowed to have common discharge piping. Since piping is a passive component that is assumed not to fail, it is allowed to be common to both

(continued)

BASES

LCO (continued)

both subsystems. In MODE 4, the RHR cross tie valve (MO-3-10-020) may be opened (per LCO 3.5.2) to allow pumps in one loop to discharge through the opposite recirculation loop to make a complete subsystem. In addition, the HPSW cross-tie valve may be opened to allow an HPSW pump in one loop to provide cooling to a heat exchanger in the opposite loop to make a complete subsystem. Additionally, 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 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 required RHR shutdown cooling subsystems to be shut down for a period of 2 hours in an 8 hour period. Note 2 allows one required 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 212°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 shutdown cooling isolation 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 above the RHR shutdown cooling isolation pressure is typically accomplished by condensing the steam in the main condenser.

(continued)

BASES

APPLICABILITY (continued)

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 RHR shutdown cooling isolation pressure and in MODE 5 are discussed in LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown"; LCO 3.9.7, "Residual Heat Removal (RHR)—High Water Level"; and LCO 3.9.8, "Residual Heat Removal (RHR)—Low Water Level."

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 required 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 required 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

(continued)

BASES

ACTIONS

A.1 (continued)

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 Condensate/Main Steam Systems (feed and bleed) and the Reactor Water Cleanup System.

B.1 and B.2

With no RHR shutdown cooling subsystem and no recirculation pump in operation, except as 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS	SR 3.4.8.1 This Surveillance verifies that one required 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	None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 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, and inservice leakage and hydrostatic testing, and also limits the maximum rate of change of reactor coolant temperature. The criticality curve provides limits for both heatup and criticality.

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 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, abnormal operational transients, and system hydrostatic tests. It mandates the use of the 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 with the UFSAR (Ref. 3) and Appendix H of 10 CFR 50 (Ref. 4). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of Reference 5.

(continued)

BASES

BACKGROUND (continued)

The P/T limit curves are composite curves established by superimposing limits derived from stress 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.

The 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 60°F above the adjusted reference temperature of the reactor vessel material in the region that is controlling (reactor vessel flange region).

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the reactor pressure vessel, 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. 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 reactor pressure vessel, a condition that is unanalyzed. Reference 7 approved the curves and limits specified in this section. 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	RCS P/T limits satisfy Criterion 2 of the NRC Policy Statement.

LCO

The elements of this LCO are:

a. RCS pressure and temperature are within the limits specified in Figures 3.4.9-1 and 3.4.9-2, and heatup and cooldown rates are ≤ 100°F during RCS heatup, cooldown, and inservice leak and hydrostatic testing;

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;

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;

d. RCS pressure and temperature are within the criticality limits specified in Figure 3.4.9-3 prior to achieving criticality; and

e. The reactor vessel flange and the head flange temperatures are > 70°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.

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 leakage 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.

(continued)

BASES

LCO (continued)

Violation of the limits places the reactor vessel outside of the bounds of the stress 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 existences, sizes, and orientations 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 MODES 1, 2, and 3 must be corrected so that the RCPB is returned to a condition that has been verified by stress 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 and must be completed if continued operation is desired. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, 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.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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 placed in 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 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.

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 stress analyses. The Required Action must be initiated without delay and continued until the limits are restored.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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 > 212°F. 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 beltline.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

Verification that operation is within limits is required every 30 minutes when RCS pressure and temperature conditions are undergoing planned changes. Plant procedures specify the pressure and temperature monitoring points to be used during the performance of this Surveillance. 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 a reasonable time for assessment and correction of minor deviations.

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.

This SR has been modified with a Note that requires this Surveillance to be performed only during system heatup and cooldown operations and inservice leakage and hydrostatic testing.

SR 3.4.9.2

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.9.2 (continued)

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 3.4.9.3 and SR 3.4.9.4

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. 8) are satisfied.

Performing the Surveillance within 15 minutes before starting the idle recirculation pump provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the idle pump start.

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.9.4 is to compare the temperatures of the operating recirculation loop and the idle loop.

SR 3.4.9.3 and SR 3.4.9.4 have been modified by a Note that requires the Surveillance to be met only in MODES 1, 2, 3, and 4. In MODE 5, the overall stress on limiting components is lower. Therefore, ΔT limits are not required. The Note also states the SR is only required to be met during a recirculation pump startup, since this is when the stresses occur.

SR 3.4.9.5, SR 3.4.9.6, and SR 3.4.9.7

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 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.9.5, SR 3.4.9.6, and SR 3.4.9.7 (continued)

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 ≤ 80°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 temperature is within the limits specified.

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 3.4.9.5 is modified by a Note that requires the Surveillance to be performed only when tensioning the reactor vessel head bolting studs. SR 3.4.9.6 is modified by a Note that requires the Surveillance to be initiated 30 minutes after RCS temperature ≤ 80°F in MODE 4. SR 3.4.9.7 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 limits specified.

REFERENCES

1. 10 CFR 50, Appendix G.

2. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.

3. UFSAR, Section 4.2.6 and Appendix K.

4. 10 CFR 50, Appendix H.

5. Regulatory Guide 1.99, Revision 2, May 1988.

(continued)

BASES

REFERENCES (continued)

6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

7. R.J. Clark (NRC) letter to G.J. Beck (PECo), Amendment Nos. 162 and 164 to Facility Operating License Nos. DPR-44 and DPR-56 for Peach Bottom Atomic Power Station Unit Nos. 2 and 3, dated June 27, 1991.

8. UFSAR, Section 14.5.6.2.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 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 and transients.
APPLICABLE SAFETY ANALYSES	The reactor steam dome pressure of ≤ 1053 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 along with Reference 1 assumes an initial reactor steam dome pressure for the analysis of design basis accidents 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% cladding plastic strain (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"). Reactor steam dome pressure satisfies the requirements of Criterion 2 of the NRC Policy Statement.
LCO	The specified reactor steam dome pressure limit of ≤ 1053 psig ensures the plant is operated within the assumptions of the reactor overpressure protection analysis. Operation above the limit may result in a transient response more severe than analyzed.
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 the events which may challenge the overpressure limits are possible.

(continued)

BASES

APPLICABILITY (continued)	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 occurring while pressure is greater than the limit is minimized.

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 3.4.10.1

Verification that reactor steam dome pressure is ≤ 1053 psig ensures that the initial conditions of the reactor overpressure protection analysis and design basis accidents are met. Operating experience has shown the 12 hour Frequency to be sufficient for identifying trends and verifying operation within safety analyses assumptions.

REFERENCES

1. Letter G94-PEPR-002A, Peach Bottom Rerate Project Overpressure Analysis at LCO Dome Pressure, from G.V. Kumar (GE) to T.E. Shannon (PECo), January 18, 1994.

2. UFSAR, Chapter 14.

BACKGROUND (continued)

The two LPCI subsystems can be interconnected via the LPCI cross tie valve; however, the cross tie valve is maintained closed with its power removed to prevent loss of both LPCI subsystems during a LOCA. The LPCI subsystems are designed to provide core cooling at low RPV pressure. Upon receipt of an initiation signal, all four LPCI pumps are automatically started (if offsite power is available, A and B pumps in approximately 2 seconds and C and D pumps in approximately 8 seconds, and, if offsite power is not available, all pumps immediately after AC power is available). Since one DG supplies power to an RHR pump in both units, the RHR pump breakers are interlocked between units to prevent operation of an RHR pump from both units on one DG and potentially overloading the affected DG. RHR System valves in the LPCI flow path are automatically positioned to ensure the proper flow path for water from the suppression pool to inject into the recirculation loops. When the RPV pressure drops sufficiently, the LPCI flow to the RPV, via the corresponding recirculation loop, begins. The water then enters the reactor through the jet pumps. Full flow test lines are provided for the four LPCI pumps to route water to the suppression pool, to allow testing of the LPCI pumps without injecting water into the RPV. These test lines also provide suppression pool cooling capability, as described in LCO 3.6.2.3, "RHR Suppression Pool Cooling."

The HPCI System (Ref. 3) 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 feedwater system line, where the coolant is distributed within the RPV through the feedwater sparger. Suction piping for the system is provided from the CST and the suppression pool. Pump suction for HPCI is normally aligned to the CST source to minimize injection of suppression pool water into the RPV. However, if the CST water supply is low, or if the suppression pool level is high, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the HPCI System. The steam supply to the HPCI turbine is piped from a main steam line upstream of the associated inboard main steam isolation valve.

The HPCI System is designed to provide core cooling for a wide range of reactor pressures (150 psig to 1150 psig,). Upon receipt of an initiation signal, the HPCI turbine stop valve and turbine control valve open and the turbine accelerates to a specified speed. As the HPCI flow

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	This LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 8), will be met following a LOCA, assuming the worst case single active component failure in the ECCS:

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

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

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

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

e. Adequate long term cooling capability is maintained.

The limiting single failures are discussed in Reference 7. The remaining OPERABLE ECCS subsystems provide the capability to adequately cool the core and prevent excessive fuel damage.

The ECCS satisfy Criterion 3 of the NRC Policy Statement.

LCO

Each ECCS injection/spray subsystem and five ADS valves are required to be OPERABLE. The ECCS injection/spray subsystems are defined as the two CS subsystems, the two LPCI subsystems, and one HPCI System. The low pressure ECCS injection/spray subsystems are defined as the two CS subsystems and the two LPCI subsystems.

With less than the required number of ECCS subsystems OPERABLE, the potential exists that during a limiting design basis LOCA concurrent with the worst case single failure, the limits specified in Reference 8 could be exceeded. All ECCS subsystems must therefore be OPERABLE to satisfy the single failure criterion required by Reference 8.

LPCI subsystems may be considered OPERABLE during alignment and operation for decay heat removal when below the actual RHR shutdown cooling isolation pressure in MODE 3, if capable of being manually realigned (remote or local) to the

(continued)

BASES

LCO (continued)

One LPCI subsystem may be aligned for decay heat removal and considered OPERABLE for the ECCS function, if it can be manually realigned (remote or local) to the LPCI mode and is not otherwise inoperable. 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 low pressure 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, the water level maintained at ≥ 458 inches above reactor pressure vessel instrument zero (20 ft 11 inches above the RPV flange), and no operations with a potential for draining the reactor vessel (OPDRVs) in progress. 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 ≤ 100 psig, and the CS System and the LPCI subsystems can provide core cooling without any depressurization of the primary system.

The High Pressure Coolant Injection System is not required to be OPERABLE during MODES 4 and 5 since the low pressure ECCS injection/spray subsystems can provide sufficient flow to the vessel.

ACTIONS

A.1 and B.1

If any one required low pressure ECCS injection/spray subsystem is inoperable, an inoperable subsystem must be restored to OPERABLE status in 4 hours. In this Condition, the remaining OPERABLE subsystem can provide sufficient vessel flooding capability to recover from an inadvertent vessel draindown. However, overall system reliability is reduced because a single failure in the remaining OPERABLE

(continued)

BASES

ACTIONS

A.1 and B.1 (continued)

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 low pressure ECCS injection/spray subsystem to OPERABLE status is based on engineering judgment that considered the remaining available subsystem and the low probability of a vessel draindown event.

With the inoperable subsystem not restored to OPERABLE status in the required Completion Time, action must be immediately initiated to suspend 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

With both of the required ECCS injection/spray subsystems inoperable, all coolant inventory makeup capability may be unavailable. Therefore, actions must immediately be initiated to suspend OPDRVs 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.

If at least one low pressure 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 for Unit 3 is OPERABLE; and secondary containment isolation capability (i.e., one isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability) in each associated secondary containment penetration flow path not isolated that is assumed to be isolated to mitigate radioactivity releases. OPERABILITY may be verified by an administrative check, or by examining logs or other information, to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1 (continued)

testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall primary containment leakage rate. The Frequency is required by 10 CFR 50, Appendix J (Ref. 2), as modified by approved exemptions. Thus, SR 3.0.2 (which allows Frequency extensions) does not apply.

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

SR 3.6.1.2.2

The air lock interlock mechanism is designed to prevent simultaneous opening of both doors in the air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident primary containment pressure, closure of either door will support primary containment OPERABILITY. Thus, the interlock feature supports primary containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous inner and outer door opening will not inadvertently occur. Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is only challenged when primary containment is entered, this test is only required to be performed upon entering primary containment, but is not required more frequently than 184 days when primary containment is de-inerted. The 184 day Frequency is based on engineering judgment and is considered adequate in view of other administrative controls available to operations personnel.

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B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources—Operating

BASES

BACKGROUND

The unit AC sources for the Class 1E AC Electrical Power Distribution System consist of the offsite power sources, and the onsite standby power sources (diesel generators (DGs)). As required by UFSAR Sections 1.5 and 8.4.2 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The Class 1E AC distribution system is divided into redundant load groups, so loss of any one group does not prevent the minimum safety functions from being performed. Each load group has connections to two qualified circuits that connect the unit to multiple offsite power supplies and a single DG.

The two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System are supported by multiple, independent offsite power sources. One of these qualified circuits can be connected to either of two offsite sources: the preferred offsite source is the 230 kV Nottingham-Graceton line which supplies the plant through the 230/13.8 kV startup and emergency auxiliary transformer no. 2; the alternate offsite source is the auto-transformer (500/230 kV) at North Substation which feeds a 230/13.8 kV regulating transformer (startup and emergency auxiliary transformer no. 3), the 3SU regulating transformer switchgear, and the 2SUA switchgear. The aligned source is further stepped down via the 2SU startup transformer switchgear through the 13.2/4.16 kV emergency auxiliary transformer no. 2. The other qualified circuit can be connected to either of two offsite sources: the preferred offsite source is the 230 kV Peach Bottom-Newlinville line which supplies a 230/13.8 kV transformer (startup transformer no. 343); the alternate offsite source is the auto-transformer (500/230 kV) at North Substation which feeds a 230/13.8 kV regulating transformer (startup and emergency auxiliary transformer no. 3) and the 3SU regulating transformer switchgear. The aligned source is further stepped down via the 343SU transformer switchgear

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the UFSAR, Chapter 14 (Ref. 4), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the onsite or offsite AC sources OPERABLE during accident conditions in the event of:

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

b. A worst case single failure.

AC sources satisfy Criterion 3 of the NRC Policy Statement.

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Distribution System and four separate and independent DGs ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an abnormal operational transient or a postulated DBA. In addition, since some equipment required by Unit 3 is powered from Unit 2 sources (i.e., Containment Atmospheric Dilution System, Standby Gas Treatment System, Emergency Service Water System, Main Control Room Emergency Ventilation System, and Unit 2 125 VDC battery chargers), qualified circuit(s) between the offsite transmission network and the Unit 2 onsite Class 1E distribution subsystem(s) needed to support this equipment must also be OPERABLE.

An OPERABLE qualified Unit 3 offsite circuit consists of the incoming breaker and disconnect to the startup and emergency auxiliary transformer, the respective circuit path to the emergency auxiliary transformer, and the circuit path to at least three Unit 3 4 kV emergency buses including feeder

(continued)

BASES

LCO (continued)

breakers to the three Unit 3 4 kV emergency buses. If at least one of the two circuits does not provide power or is not capable of providing power to all four Unit 3 4 kV emergency buses, then the Unit 3 4 kV emergency buses than each circuit powers or is capable of powering cannot all be the same (i.e., two feeder breakers on one Unit 3 4 kV emergency bus cannot be inoperable). An OPERABLE qualified Unit 2 offsite circuit's requirements are the same as the Unit 3 circuit's requirements, except that the circuit path, including the feeder breakers, is to the Unit 2 4 kV emergency buses required to be OPERABLE by LCO 3.8.7, "Distribution Systems—Operating." Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the emergency buses.

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective Unit 3 4 kV emergency bus on detection of bus undervoltage. This sequence must be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the emergency buses. These capabilities are required to be met from a variety of initial conditions, such as DG in standby with the engine hot and DG in standby with the engine at ambient condition. Additional DG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode. Proper sequencing of loads, including tripping of all loads, is a required function for DG OPERABILITY.

In addition, since some equipment required by Unit 3 is powered from Unit 2 sources, the DG(s) capable of supplying the Unit 2 onsite Class 1E AC electrical power distribution subsystem(s) needed to support this equipment must be OPERABLE. The OPERABILITY requirements for these DGs are the same as described above, except that each required DG must be capable of connecting to its respective Unit 2 4 kV emergency bus. (In addition, the Unit 2 ECCS initiation logic SRs are not applicable, as described in SR 3.8.1.21 Bases.)

The AC sources must be separate and independent (to the extent possible) of other AC sources. For the DGs, the separation and independence are complete. For the offsite

(continued)

BASES

LCO (continued)

AC sources, the separation and independence are to the extent practical. A circuit may be connected to more than one 4 kV emergency bus division, with automatic transfer capability to the other circuit OPERABLE, and not violate separation criteria. A circuit that is not connected to at least three 4 kV emergency buses is required to have OPERABLE automatic transfer interlock mechanisms such that it can provide power to at least three 4 kV emergency buses to support OPERABILITY of that circuit.

APPLICABILITY

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

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

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

The AC power requirements for MODES 4 and 5 are covered in LCO 3.8.2, "AC Sources—Shutdown."

ACTIONS

A.1

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

A.2

Required Action A.2, which only applies if one 4 kV emergency bus cannot be powered from any offsite source, is intended to provide assurance that an event with a coincident single failure of the associated DG does not result in a complete loss of safety function of critical systems. These features (e.g., system, subsystem, division,

(continued)

BASES

ACTIONS

A.2 (continued)

component, or device) are designed to be powered from redundant safety related 4 kV emergency buses. Redundant required features failures consist of inoperable features associated with an emergency bus redundant to the emergency bus that has no offsite power.

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

a. A 4 kV emergency bus has no offsite power supplying its loads; and

b. A redundant required feature on another 4 kV emergency bus is inoperable.

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

Discovering no offsite power to one 4 kV emergency bus of the onsite Class 1E Power Distribution System coincident with one or more inoperable required support or supported features, or both, that are associated with any other emergency bus that has offsite power, results in starting the Completion Times for the Required Action. Twenty-four hours is acceptable because it minimizes risk while allowing time for restoration before the unit is subjected to transients associated with shutdown.

The remaining OPERABLE offsite circuits and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection may have been lost for the required feature's function; however, function is not lost. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.4.2.1 and B.4.2.2

The 33 kV Conowingo Tie-Line using a separate 33/13.8 kV transformer, can be used to supply the circuit normally supplied by startup and emergency auxiliary transformer no. 2. While not a qualified circuit, this alternate source is a direct tie to the Conowingo Hydro Station that provides a highly reliable source of power because: the line and transformers at both ends of the line are dedicated to the support of PBAPS; the tie line is not subject to damage from adverse weather conditions; and, the tie line can be isolated from other parts of the grid when necessary to ensure its availability and stability to support PBAPS. The availability of this highly reliable source of offsite power permits an extension to the 7 day allowable out of service time for a DG. Therefore, prior to the time period that the normal 7 day allowable out of service time for a DG is exceeded, it is necessary to verify the availability of the Conowingo Tie-Line. The Conowingo Tie-Line is available and satisfies the requirements of Required Action B.4.2.1 if: 1) the tie-line is supplying power to PBAPS Unit 1; 2) manual breaker operation is available to tie power from the Unit 1/Conowingo Tie-Line to the startup and emergency auxiliary transformer no. 2; and 3) communications with the Conowingo control room is available to ensure that required equipment at Conowingo is available. The Completion Time for the restoration of the DG to OPERABLE status may not be extended beyond 7 days from the initial time that Condition B was entered (the time allowed by Required Action B.4.1) if Required Action B.4.2.1 is not satisfied within 7 days. If the status of the Conowingo Tie-Line changes after Required Action B.4.2.1 is initially met, such that the DG restoration time is now 7 days (per Required Action B.4.1), the 7 days begins upon discovery of failure to meet Required Action B.4.2.1. However, the total time to restore an inoperable DG cannot exceed 14 days (per the second Completion Time of Required Action B.4.1).

The availability of the Conowingo Tie-Line provides an additional source which permits operation to continue in Condition B for a period that should not exceed 30 days. In Condition B, the remaining OPERABLE DGs and the normal offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 30 day Completion Time takes into account the enhanced reliability

(continued)

BASES

ACTIONS

B.4.2.1 and B.4.2.2 (continued)

and availability of offsite sources due to the Conowingo Tie-Line, the redundancy, capacity, and capability of the other remaining AC sources, reasonable time for repairs of the affected DG, and low probability of a DBA occurring during this period.

C.1 and C.2

Required Action C.1 addresses actions to be taken in the event of inoperability of redundant required features concurrent with inoperability of two or more offsite circuits. Required Action C.1 reduces the vulnerability to a loss of function. The Completion Time for taking these actions is reduced to 12 hours from that allowed with one 4 kV emergency bus without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two offsite circuits inoperable, based upon the assumption that two complete safety divisions are OPERABLE. (While this Action allows more than two circuits to be inoperable, Regulatory Guide 1.93 assumed two circuits were all that were required by the LCO, and a loss of those two circuits resulted in a loss of all offsite power to the Class 1E AC Electrical Power Distribution System. Thus, with the Peach Bottom Atomic Power Station design, a loss of more than two offsite circuits results in the same conditions assumed in Regulatory Guide 1.93.) When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are designed with redundant safety related 4 kV emergency buses. Redundant required features failures consist of any of these features that are inoperable because any inoperability is on an emergency bus redundant to an emergency bus with inoperable offsite circuits. B

The Completion Time for Required Action C.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

(continued)

BASES

ACTIONS (continued)

G.1

Condition G corresponds to a level of degradation in which redundancy in the AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC electrical power system may cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with UFSAR, Section 1.5.1 (Ref. 7). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), Regulatory Guide 1.108 (Ref. 8), and Regulatory Guide 1.137 (Ref. 9).

As Noted at the beginning of the SRs, SR 3.8.1.1 through SR 3.8.1.20 are applicable only to the Unit 3 AC sources and SR 3.8.1.21 is applicable only to the Unit 2 AC sources.

Where the SRs discussed herein specify voltage and frequency tolerances, the following summary is applicable. The minimum steady state output voltage of 4160 V corresponds to the minimum steady state voltage analyzed in the PBAPS emergency DG voltage regulation study. This value allows for voltage drops to motors and other equipment down through the 120 V level. The specified maximum steady state output voltage of 4400 V is equal to the maximum steady state operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated steady state operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations found in Regulatory Guide 1.9 (Ref. 3). B

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source and that appropriate independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

SR 3.8.1.2 and SR 3.8.1.7

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

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs have been modified by a Note (Note 2 for SR 3.8.1.2 and Note 1 for SR 3.8.1.7) to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period and followed by a warmup prior to loading.

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

In order to reduce stress and wear on diesel engines, the manufacturer recommends a modified start in which the starting speed of DGs is limited, warmup is limited to this lower speed, and the DGs are gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 3 to SR 3.8.1.2, which is only applicable when such modified start procedures are recommended by the manufacturer.

SR 3.8.1.7 requires that, at a 184 day Frequency, the DG starts from standby conditions and achieves required voltage and frequency within 10 seconds. The minimum voltage and frequency stated in the SR are those necessary to ensure the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

DG can accept DBA loading while maintaining acceptable voltage and frequency levels. Stable operation at the nominal voltage and frequency values is also essential to establishing DG OPERABILITY, but a time constraint is not imposed. This is because a typical DG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not damped out by load application. This period may extend beyond the 10 second acceptance criteria and could be a cause for failing the SR. In lieu of a time constraint in the SR, PBAPS will monitor and trend the actual time to reach steady state operation as a means of ensuring there is no voltage regulator or governor degradation which could cause a DG to become inoperable. The 10 second start requirement supports the assumptions in the design basis LOCA analysis of UFSAR, Section 8.5 (Ref. 10). The 10 second start requirement is not applicable to SR 3.8.1.2 (see Note 3 of SR 3.8.1.2), when a modified start procedure as described above is used. If a modified start is not used, the 10 second start requirement of SR 3.8.1.7 applies.

Since SR 3.8.1.7 requires a 10 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This procedure is the intent of Note 1 of SR 3.8.1.2.

To minimize testing of the DGs, Note 4 to SR 3.8.1.2 and Note 2 to SR 3.8.1.7 allow a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit. If the DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

The normal 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 3). The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 5). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing and accepting a load approximately equivalent to that corresponding to the continuous rating. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

This Surveillance verifies, indirectly, that the DGs are capable of synchronizing and accepting loads equivalent to post accident loads. The DGs are tested at a load approximately equivalent to their continuous duty rating, even though the post accident loads exceed the continuous rating. This is acceptable because regular surveillance testing at post accident loads is injurious to the DG, and imprudent because the same level of assurance in the ability of the DG to provide post accident loads can be developed by monitoring engine parameters during surveillance testing. The values of the testing parameters can then be qualitatively compared to expected values at post accident engine loads. In making this comparision it is necessary to consider the engine parameters as interrelated indicators of remaining DG capacity, rather than independent indicators. The important engine parameters to be considered in making this comparision include, fuel rack position, scavenging air pressure, exhaust temperature and pressure, engine output, jacket water temperature, and lube oil temperature. With the DG operating at or near continuous rating and the observed values of the above parameters less than expected post accident values, a qualitative extrapolation which shows the DG is capable of accepting post accident loads can be made without requiring deterimental testing. B

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

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

Note 1 modifies this Surveillance to indicate that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized.

Note 2 modifies this Surveillance by stating that momentary transients because of changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the limit do not invalidate the test.

Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations.

Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

To minimize testing of the DGs, Note 5 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units, with the DG synchronized to the 4 kV emergency bus of Unit 3 for one periodic test and synchronized to the 4 kV emergency bus of Unit 2 during the next periodic test. This is allowed since the main purpose of the Surveillance, to ensure DG OPERABILITY, is still being verified on the proper frequency, and each unit's breaker control circuitry, which is only being tested every second test (due to the staggering of the tests), historically have a very low failure rate. If the DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit. In addition, if the test is scheduled to be performed on Unit 2, and the Unit 2 TS allowance that provides an exception to performing the test is used (i.e., when Unit 2 is in MODE 4 or 5, or moving irradiated fuel assemblies in the secondary containment, the Note to Unit 2 SR 3.8.2.1 provides an exception to performing this test), then the test shall be performed synchronized to the Unit 3 4 kV emergency bus.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is adequate for a minimum of 1 hour of DG operation at full load. The level is expressed as an equivalent volume in gallons.

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

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are consistent with Regulatory Guide 1.137 (Ref. 9). This SR is for preventive maintenance. The presence of water does not necessarily represent a failure of this SR provided that accumulated water is removed during performance of this Surveillance.

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and automatically transfers fuel oil from its associated storage tank to its associated day tank. It is required to support continuous operation of standby power sources. This Surveillance provides assurance that

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.6 (continued)

the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

The Frequency for this SR is 31 days because the design of the fuel transfer system is such that pumps operate automatically in order to maintain an adequate volume of fuel oil in the day tanks during or following DG testing and proper operation of fuel transfer systems is an inherent part of DG OPERABILITY.

SR 3.8.1.8

Transfer of each 4 kV emergency bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The 24 month Frequency of the Surveillance is based on engineering judgment taking into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components will pass the SR when performed on the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that, during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. This Surveillance tests the applicable logic associated with Unit 3. The comparable test specified in Unit 2 Technical Specifications tests the applicable logic associated with Unit 2. Consequently, a test must be performed within the specified Frequency for each unit. As the Surveillance represents separate tests, the Note specifying the restriction for not performing the test while the unit is in MODE 1 or 2 does not have applicability to Unit 2. The Note only applies to Unit 3, thus the Unit 3 Surveillance shall not be performed with Unit 3 in MODE 1 or 2. Credit may be taken for unplanned events that satisfy this SR.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. The largest single load for each DG is a residual heat removal pump (2000 bhp). This Surveillance may be accomplished by: 1) tripping the DG output breakers with the DG carrying greater than or equal to its associated single largest post-accident load while paralleled to offsite power, or while solely supplying the bus, or 2) tripping its associated single largest post-accident load with the DG solely supplying the bus. Currently, the second option is the method PBAPS utilizes because the first method will result in steady state operation outside the allowable voltage and frequency limits. Consistent with Regulatory Guide 1.9 (Ref. 3), the load rejection test is acceptable if the diesel speed does not exceed the nominal (synchronous) speed plus 75% of the difference between nominal speed and the overspeed trip setpoint, or 115% of nominal speed, whichever is lower.

The time, voltage, and frequency tolerances specified in this SR are derived from Regulatory Guide 1.9 (Ref. 3) recommendations for response during load sequence intervals. The 1.8 seconds specified for voltage and the 2.4 seconds specified for frequency are equal to 60% and 80%, respectively, of the 3 second load sequence interval associated with sequencing the next load following the residual heat removal (RHR) pumps during an undervoltage on the bus concurrent with a LOCA. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.9.a corresponds to the maximum frequency excursion, while SR 3.8.1.9.b and SR 3.8.1.9.c provide steady state voltage and frequency values to which the system must recover following load rejection. The 24 month Frequency takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

This SR is modified by two Notes. In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, Note 1 requires that if synchronized to offsite power, testing must be performed using a power factor ≤ 0.89. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.

To minimize testing of the DGs, Note 2 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit. If the DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.10

Consistent with Regulatory Guide 1.9 (Ref. 3), paragraph C.2.2.8, this Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide DG damage protection. While the DG is not expected to experience this transient during an event, and continue to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing must be performed using a power factor ≤ 0.89. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

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

This SR is modified by a Note. To minimize testing of the DGs, the Note allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit. If the DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.11

Consistent with Regulatory Guide 1.9 (Ref. 3), paragraph C.2.2.4, this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of all loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

The DG auto-start and energization of the associated 4 kV emergency bus time of 10 seconds is derived from requirements of the accident analysis for responding to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved.

The requirement to verify the connection and power supply of auto-connected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, Emergency Core Cooling Systems (ECCS) injection valves are not desired to be stroked open, or systems are not capable of being operated at full flow, or RHR systems performing a decay

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

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

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs shall be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This Surveillance tests the applicable logic associated with Unit 3. The comparable test specified in the Unit 2 Technical Specifications tests the applicable logic associated with Unit 2. Consequently, a test must be performed within the specified Frequency for each unit. As the Surveillance represents separate tests, the Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 2. The Note only applies to Unit 3, thus the Unit 3 Surveillances shall not be performed with Unit 3 in MODE 1, 2, or 3. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.12

Consistent with Regulatory Guide 1.9 (Ref. 3), paragraph C.2.2.5, this Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (10 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The minimum voltage and frequency stated in the SR are those necessary to ensure the DG can accept

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

DBA loading while maintaining acceptable voltage and frequency levels. Stable operation at the nominal voltage and frequency values is also essential to establishing DG OPERABILITY, but a time constraint is not imposed. This is because a typical DG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not damped out by load application. This period may extend beyond the 10 second acceptance criteria and could be a cause for failing the SR. In lieu of a time constraint in the SR, PBAPS will monitor and trend the actual time to reach steady state operation as a means of ensuring there is no voltage regulator or governor degradation which could cause a DG to become inoperable. The 5 minute period provides sufficient time to demonstrate stability. SR 3.8.1.12.d and SR 3.8.1.12.e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on a LOCA signal without loss of offsite power.

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

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

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

SR 3.8.1.13

Consistent with Regulatory Guide 1.9 (Ref. 3), paragraph C.2.2.12, this Surveillance demonstrates that DG non-critical protective functions (e.g., high jacket water temperature) are bypassed on an ECCS initiation test signal and critical protective functions (engine overspeed, generator differential overcurrent, generator ground neutral overcurrent, and manual cardox initiation) trip the DG to avert substantial damage to the DG unit. The non-critical trips are bypassed during DBAs and continue to provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

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

To minimize testing of the DGs, the Note to this SR allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit. If the DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.14

Consistent with Regulatory Guide 1.9 (Ref. 3), paragraph C.2.2.9, this Surveillance requires demonstration that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours—22 hours of which is at a load equivalent to 90% to 100% of the continuous duty rating of the DG, and 2 hours of which is at a load equivalent to 105% to 110% of the continuous duty rating of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelube and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

This Surveillance verifies, indirectly, that the DGs are capable of synchronizing and accepting loads equivalent to post accident loads. The DGs are tested at a load approximately equivalent to their continuous duty rating, even though the post accident loads exceed the continuous rating. This is acceptable because regular surveillance testing at post accident loads is injurious to the DG, and imprudent because the same level of assurance in the ability of the DG to provide post accident loads can be developed by monitoring engine parameters during surveillance testing. The values of the testing parameters can then be qualitatively compared to expected values at post accident engine loads. In making this comparision it is necessary to consider the engine parameters as interrelated indicators of remaining DG capacity, rather than independent indicators. The important engine parameters to be considered in making this comparision include, fuel rack position, scavenging air pressure, exhaust temperature and pressure, engine output, jacket water temperature, and lube oil temperature. With the DG operating at or near continuous rating and the observed values of the above parameters less than expected post accident values, a qualitative extrapolation which shows the DG is capable of accepting post accident loads can be made without requiring deterimental testing. B

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed using a power factor ≤ 0.89. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

experience. A load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

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

This Surveillance has been modified by three Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the limit do not invalidate the test. Note 2 is provided in recognition that if the offsite electrical power distribution system voltage is high, it may not be possible to raise DG output voltage without creating an overvoltage condition on the emergency bus. Therefore, to ensure the bus voltage and supplied loads, and DG are not placed in an unsafe condition during this test, the power factor limit does not have to be met if grid voltage or emergency bus loading does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the power factor should be maintained as close to the limit as practicable. To minimize testing of the DGs, Note 3 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit. If the DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 10 seconds. The minimum voltage and frequency stated in the SR are those necessary to ensure the DG can accept DBA loading while maintaining acceptable voltage and frequency levels. Stable operation at the nominal voltage and frequency values is also essential to establishing DG OPERABILITY, but a time constraint is not imposed. This is because a typical DG will experience a B

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.15 (continued)

period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not damped out by load application. This period may extend beyond the 10 second acceptance criteria and could be a cause for failing the SR. In lieu of a time constraint in the SR, PBAPS will monitor and trend the actual time to reach steady state operation as a means of ensuring there is no voltage regulator or governor degradation which could cause a DG to become inoperable. The 10 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The 24 month Frequency takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by three Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The requirement that the diesel has operated for at least 2 hours at full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing. To minimize testing of the DGs, Note 3 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit. If the DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.16

Consistent with Regulatory Guide 1.9 (Ref. 3), paragraph C.2.2.11, this Surveillance ensures that the manual synchronization and load transfer from the DG to the offsite source can be made and that the DG can be returned

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.16 (continued)

to ready-to-load status when offsite power is restored. It also ensures that the auto-start logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready-to-load status when the DG is at rated speed and voltage, the output breaker is open and can receive an auto-close signal on bus undervoltage, and individual load timers are reset.

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

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This Surveillance tests the applicable logic associated with Unit 3. The comparable test specified in the Unit 2 Technical Specifications tests the applicable logic associated with Unit 2. Consequently, a test must be performed within the specified Frequency for each unit. As the Surveillance represents separate tests, the Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 2. The Note only applies to Unit 3, thus the Unit 3 Surveillances shall not be performed with Unit 3 in MODE 1, 2, or 3. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.17

Consistent with Regulatory Guide 1.9 (Ref 3), paragraph C.2.2.13, demonstration of the test mode override ensures that the DG availability under accident conditions is not compromised as the result of testing. Interlocks to the LOCA sensing circuits cause the DG to automatically reset to ready-to-load operation if a Unit 3 ECCS initiation signal is received during operation in the test mode while synchronized to either Unit 2 or a Unit 3 4 kV emergency bus. Ready-to-load operation is defined as the DG running at rated speed and voltage with the DG output breaker open.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

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

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

To minimize testing of the DGs, the Note allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit. If the DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.18

Under accident and loss of offsite power conditions, loads are sequentially connected to the bus by individual load timers. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor starting currents. The 10% load sequence time interval tolerance ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 10 provides a summary of the automatic loading of emergency buses.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.18 (continued)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This Surveillance tests the applicable logic associated with Unit 3. The comparable test specified in the Unit 2 Technical Specifications tests the applicable logic associated with Unit 2. Consequently, a test must be performed within the specified Frequency for each unit. As the Surveillance represents separate tests, the Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 3. The Note only applies to Unit 3, thus the Unit 3 Surveillances shall not be performed with Unit 3 in MODE 1, 2, or 3. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.19

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

This Surveillance demonstrates DG operation, as discussed in the Bases for SR 3.8.1.11, during a loss of offsite power actuation test signal in conjunction with an ECCS initiation signal. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

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

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.19 (continued)

consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This Surveillance tests the applicable logic associated with Unit 3. The comparable test specified in the Unit 2 Technical Specifications tests the applicable logic associated with Unit 2. Consequently, a test must be performed within the specified Frequency for each unit. As the Surveillance represents separate tests, the Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 2. The Note only applies to Unit 3, thus the Unit 3 Surveillances shall not be performed with Unit 3 in MODE 1, 2, or 3. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.20

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

The minimum voltage and frequency stated in the SR are those necessary to ensure the DG can accept DBA loading while maintaining acceptable voltage and frequency levels. Stable operation at the nominal voltage and frequency values is also essential to establishing DG OPERABILITY, but a time constraint is not imposed. This is because a typical DG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not damped out by load application. This period may extend beyond the 10 second acceptance criteria and could be a cause for failing the SR. In lieu of a time constraint in the SR, PBAPS will monitor and trend the actual time to reach steady state operation as a means of ensuring there is no voltage regulator or governor degradation which could cause a DG to become inoperable. B

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.20 (continued)

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 8). This SR is modified by two Notes. The reason for Note 1 is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations. To minimize testing of the DGs, Note 2 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit. If a DG fails one of these Surveillances, a DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.21

With the exception of this Surveillance, all other Surveillances of this Specification (SR 3.8.1.1 through SR 3.8.1.20) are applied only to the Unit 3 AC sources. This Surveillance is provided to direct that the appropriate Surveillances for the required Unit 2 AC sources are governed by the applicable Unit 2 Technical Specifications. Performance of the applicable Unit 2 Surveillances will satisfy Unit 2 requirements, as well as satisfying this Unit 3 Surveillance Requirement. Six exceptions are noted to the Unit 2 SRs of LCO 3.8.1. SR 3.8.1.8 is excepted when only one Unit 2 offsite circuit is required by the Unit 3 Specification, since there is not a second circuit to transfer to. SR 3.8.1.12, SR 3.8.1.13, SR 3.8.1.17, SR 3.8.1.18 (ECCS load block requirements only), and SR 3.8.1.19 are excepted since these SRs test the Unit 2 ECCS initiation signal, which is not needed for the AC sources to be OPERABLE on Unit 3.

The Frequency required by the applicable Unit 2 SR also governs performance of that SR for Unit 3.

As Noted, if Unit 2 is in MODE 4 or 5, or moving irradiated fuel assemblies in the secondary containment, the Note to Unit 2 SR 3.8.2.1 is applicable. This ensures that a Unit 3 SR will not require a Unit 2 SR to be performed, when the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.21 (continued)

Unit 2 Technical Specifications exempts performance of a Unit 2 SR (However, as stated in the Unit 2 SR 3.8.2.1 Note, while performance of an SR is exempted, the SR still must be met).

REFERENCES

1. UFSAR, Sections 1.5 and 8.4.2.
2. UFSAR, Sections 8.3 and 8.4.
3. Regulatory Guide 1.9, July 1993.
4. UFSAR, Chapter 14.
5. Generic Letter 84-15.
6. Regulatory Guide 1.93, December 1974.
7. UFSAR, Section 1.5.1.
8. Regulatory Guide 1.108, August 1977.
9. Regulatory Guide 1.137, October 1979.
10. UFSAR, Section 8.5.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources—Shutdown

BASES

BACKGROUND

A description of the AC sources is provided in the Bases for LCO 3.8.1, "AC Sources—Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC sources during MODES 4 and 5 and during movement of irradiated fuel assemblies in secondary containment ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.

In general, when the unit is shut down the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or loss of all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, and 3 have no specific analyses in MODES 4 and 5. Worst case bounding events are deemed not credible in MODES 4 and 5 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and corresponding stresses result in the probabilities of occurrences significantly reduced or eliminated, and minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

During MODES 1, 2, and 3, various deviations from the analysis assumptions and design requirements are allowed within the ACTIONS. This allowance is in recognition that

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

certain testing and maintenance activities must be conducted, provided an acceptable level of risk is not exceeded. During MODES 4 and 5, performance of a significant number of required testing and maintenance activities is also required. In MODES 4 and 5, the activities are generally planned and administratively controlled. Relaxations from typical MODES 1, 2, and 3 LCO requirements are acceptable during shutdown MODES, based on:

a. The fact that time in an outage is limited. This is a risk prudent goal as well as a utility economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operation MODE analyses, or both.

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODES 1, 2, and 3 OPERABILITY requirements) with systems assumed to function during an event.

In the event of an accident during shutdown, this LCO ensures the capability of supporting systems necessary for avoiding immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite (diesel generator (DG)) power.

The AC sources satisfy Criterion 3 of the NRC Policy Statement.

LCO

One offsite circuit supplying the Unit 3 onsite Class 1E power distribution subsystem(s) of LCO 3.8.8, "Distribution Systems—Shutdown," ensures that all required Unit 3 powered loads are powered from offsite power. Two OPERABLE DGs, associated with the Unit 3 onsite Class 1E power distribution subsystem(s) required OPERABLE by LCO 3.8.8, ensures that a diverse power source is available for providing electrical power support assuming a loss of the

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BASES

LCO (continued)

offsite circuit. In addition some equipment that may be required by Unit 3 is powered from Unit 2 sources (e.g., Containment Atmospheric Dilution System, Standby Gas Treatment System, Emergency Service Water System, and Main Control Room Emergency Ventilation System). Therefore, qualified circuits between the offsite transmission network and the Unit 2 onsite Class 1E AC electrical power distribution subsystem(s), and the DG(s) (not necessarily different DG(s) from those being used to meet LCO 3.8.2.b requirements) capable of supplying power to the required Unit 2 subsystems of each of the required components must also be OPERABLE. Together, OPERABILITY of the required offsite circuit(s) and required DG(s) ensures the availability of sufficient AC sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and reactor vessel draindown).

The qualified Unit 3 offsite circuit must be capable of maintaining rated frequency and voltage while connected to the respective Unit 3 4 kV emergency bus(es), and of accepting required loads during an accident. Qualified offsite circuits are those that are described in the UFSAR and are part of the licensing basis for the unit. A Unit 3 offsite circuit consists of the incoming breaker and disconnect to the startup and emergency auxiliary transformer, the respective circuit path to the emergency auxiliary transformer and the circuit path to the Unit 3 4 kV emergency buses required by LCO 3.8.8, including feeder breakers to the required Unit 3 4 kV emergency buses. A qualified Unit 2 offsite circuit's requirements are the same as the Unit 3 circuit's requirements, except that the circuit path, including the feeder breakers, is to the Unit 2 4 kV emergency buses required to be OPERABLE by LCO 3.8.8.

The required DGs must be capable of starting, accelerating to rated speed and voltage, and connecting to their respective Unit 3 emergency bus on detection of bus undervoltage. This sequence must be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the 4 kV emergency buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with engine hot and DG in standby with engine at ambient conditions. Additional

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BASES

LCO (continued)

DG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode. Proper sequencing of loads is a required function for DG OPERABILITY. The necessary portions of the Emergency Service Water System are also required to provide appropriate cooling to each required DG.

The OPERABILITY requirements for the DG capable of supplying power to the Unit 2 powered equipment are the same as described above, except that the required DG must be capable of connecting to its respective Unit 2 4 kV emergency bus. (In addition, the Unit 2 ECCS initiation logic SRs are not applicable, as described in SR 3.8.2.2 Bases.)

It is acceptable for 4 kV emergency buses to be cross tied during shutdown conditions, permitting a single offsite power circuit to supply all required buses. No automatic transfer capability is required for offsite circuits to be considered OPERABLE.

APPLICABILITY

The AC sources are required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment to provide assurance that:

a. Systems providing adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core in case of an inadvertent draindown of the reactor vessel:

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

AC power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.1.

(continued)

BASES (continued)

ACTIONS

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

A.1 and B.1

With one or more required offsite circuits inoperable, or with one DG inoperable, the remaining required sources may be capable of supporting sufficient required features (e.g., system, subsystem, division, component, or device) to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel. For example, if two or more 4 kV emergency buses are required per LCO 3.8.8, one 4 kV emergency bus with offsite power available may be capable of supplying sufficient required features. By the allowance of the option to declare required features inoperable that are not powered from offsite power (Required Action A.1) or capable of being powered by the required DG (Required Action B.1), appropriate restrictions can be implemented in accordance with the affected feature(s) LCOs' ACTIONS. Required features remaining powered from a qualified offsite power circuit, even if that circuit is considered inoperable because it is not powering other required features, are not declared inoperable by this Required Action. If a single DG is credited with meeting both LCO 3.8.2.d and one of the DG requirements of LCO 3.8.2.b, then the required features remaining capable of being powered by the DG are not declared inoperable by this Required Action, even if the DG is considered inoperable because it is not capable of powering other required features.

A.2.1, A.2.2, A.2.3, A.2.4, B.2.1, B.2.2, B.2.3, B.2.4, C.1, C.2, C.3, and C.4

With an offsite circuit not available to all required 4 kV emergency buses or one required DG inoperable, the option still exists to declare all required features inoperable

(continued)

BASES

ACTIONS

A.2.1, A.2.2, A.2.3, A.2.4, B.2.1, B.2.2, B.2.3, B.2.4, C.1, C.2, C.3, and C.4 (continued)

(per Required Actions A.1 and B.1). Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. With two or more required DGs inoperable, the minimum required diversity of AC power sources may not be available. It is, therefore, required to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in the secondary containment, and activities that could result in inadvertent draining of the reactor vessel.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC sources and to continue this action until restoration is accomplished in order to provide the necessary AC power to the plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A have been modified by a Note to indicate that when Condition A is entered with no AC power to any required 4 kV emergency bus, ACTIONS for LCO 3.8.8 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit whether or not a required bus is de-energized. LCO 3.8.8 provides the appropriate restrictions for the situation involving a de-energized bus.

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the Unit 3 AC sources in other than MODES 1, 2, and 3. SR 3.8.1.8 is not

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1 (continued)

required to be met since only one offsite circuit is required to be OPERABLE. SR 3.8.1.17 is not required to be met because the required OPERABLE DG(s) is not required to undergo periods of being synchronized to the offsite circuit. SR 3.8.1.20 is excepted because starting independence is not required with the DG(s) that is not required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during the performance of SRs, and to preclude de-energizing a required 4 kV emergency bus or disconnecting a required offsite circuit during performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DG and offsite circuit are required to be OPERABLE.

SR 3.8.2.2

This Surveillance is provided to direct that the appropriate Surveillances for the required Unit 2 AC sources are governed by the Unit 2 Technical Specifications. Performance of the applicable Unit 2 Surveillances will satisfy Unit 2 requirements, as well as satisfying this Unit 3 Surveillance Requirement. Seven exceptions are noted to the Unit 2 SRs of LCO 3.8.1. SR 3.8.1.8 is excepted when only one Unit 2 offsite circuit is required by the Unit 3 Specification, since there is not a second circuit to transfer to. SR 3.8.1.12, SR 3.8.1.13, SR 3.8.1.17, SR 3.8.1.18 (ECCS load block requirements only), and SR 3.8.1.19 are excepted since these SRs test the Unit 2 ECCS initiation signal, which is not needed for the AC sources to be OPERABLE on Unit 3. SR 3.8.1.20 is excepted since starting independence is not required with the DG(s) that is not required to be OPERABLE.

The Frequency required by the applicable Unit 2 SR also governs performance of that SR for Unit 3.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.2.2 (continued)

As Noted, if Unit 2 is not in MODE 1, 2, or 3, the Note to Unit 2 SR 3.8.2.1 is applicable. This ensures that a Unit 3 SR will not require a Unit 2 SR to be performed, when the Unit 2 Technical Specifications exempts performance of a Unit 2 SR or when Unit 2 is defueled. (However, as stated in the Unit 2 SR 3.8.2.1 Note, while performance of an SR is exempted, the SR still must be met).

REFERENCES

None.

B 3.8 ELECTRICAL POWER SYSTEMS

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

BASES

BACKGROUND

Each of the four diesel generators (DGs) is provided with an associated storage tank which collectively have a fuel oil capacity sufficient to operate all four DGs for a period of 7 days while the DG is supplying maximum post loss of coolant accident (LOCA) load demand discussed in UFSAR, Section 8.5.2 (Ref. 1). The maximum load demand is calculated using the time dependent loading of each DG and the assumption that all four DGs are available. This onsite fuel oil capacity is sufficient to operate the DGs for longer than the time to replenish the onsite supply from outside sources. Post accident electrical loading and fuel consumption is not equally shared among the DGs. Therefore, it may be necessary to transfer post accident loads between DGs or to transfer fuel oil between storage tanks to achieve 7 days of post accident operation for all four DGs. Each storage tank contains sufficient fuel to support the operation of the DG with the heaviest load for greater than 6 days.

Each DG is equipped with a day tank and an associated fuel transfer pump that will automatically transfer oil from a fuel storage tank to the day tank of the associated DG when actuated by a float switch in the day tank. Additionally, the capability exists to transfer fuel oil between storage tanks. Redundancy of pumps and piping precludes the failure of one pump, or the rupture of any pipe, valve, or tank to result in the loss of more than one DG. All outside tanks and piping are located underground.

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

(continued)

BASES

BACKGROUND (continued)

The DG lubrication system is designed to provide sufficient lubrication to permit proper operation of its associated DG under all loading conditions. The system is required to circulate the lube oil to the diesel engine working surfaces and to remove excess heat generated by friction during operation. Each engine oil sump and associated lube oil storage tank contain an inventory capable of supporting a minimum of 7 days of operation. Each lube oil sump utilizes a mechanical float-type level controller to automatically maintain the sump at the "full level running" level via gravity feed from the associated lube oil storage tank. Onsite storage of lube oil also helps ensure a 7 day supply is maintained. This supply is sufficient to allow the operator to replenish lube oil from outside sources.

Each DG has an air start system that includes two air start receivers; each with adequate capacity for five successive normal starts on the DG without recharging the air start receiver.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in UFSAR, Chapter 8 (Ref. 4), and Chapter 14 (Ref. 5), assume Engineered Safety Feature (ESF) systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems.

Since diesel fuel oil, lube oil, and starting air subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of the NRC Policy Statement.

LCO

Stored diesel fuel oil is required to have sufficient supply for 7 days of operation at the worst case post accident time-dependent load profile. It is also required to meet specific standards for quality. Additionally, sufficient lube oil supply must be available to ensure the capability to operate at full load for 7 days. This requirement, in

(continued)

BASES

LCO (continued)

conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of DGs required to shut down both the Unit 2 and Unit 3 reactors and to maintain them in a safe condition for an abnormal operational transient or a postulated DBA in one unit with loss of offsite power. DG day tank fuel oil requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources—Operating," and LCO 3.8.2, "AC Sources—Shutdown."

The starting air system is required to have a minimum capacity for five successive DG normal starts without recharging the air start receivers. Only one air start receiver per DG is required, since each air start receiver has the required capacity.

APPLICABILITY

The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down both the Unit 2 and Unit 3 reactors and maintain them in a safe shutdown condition after an abnormal operational transient or a postulated DBA in either Unit 2 or Unit 3. Because stored diesel fuel oil, lube oil, and starting air subsystem support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil, lube oil, and starting air are required to be within limits when the associated DG is required to be OPERABLE.

ACTIONS

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

(continued)

BASES

ACTIONS (continued)

A.1

With fuel oil level < 29,000 gal in a storage tank, the 7 day fuel oil supply for a DG is not available. However, the Condition is restricted to fuel oil level reductions that maintain at least a 6 day supply. These circumstances may be caused by events such as:

a. Full load operation required for an inadvertent start while at minimum required level; or

b. Feed and bleed operations that may be necessitated by increasing particulate levels or any number of other oil quality degradations.

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

B.1

With lube oil inventory < 350 gal, sufficient lube oil to support 7 days of continuous DG operation at full load conditions may not be available. However, the Condition is restricted to lube oil volume reductions that maintain at least a 6 day supply. This restriction allows sufficient time for obtaining the requisite replacement volume. A period of 48 hours is considered sufficient to complete restoration of the required volume prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the low rate of usage, the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

(continued)

BASES

ACTIONS (continued)

C.1

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

D.1

With the new fuel oil properties defined in the Bases for SR 3.8.3.3 not within the required limits, a period of 30 days is allowed for restoring the stored fuel oil properties. This period provides sufficient time to test the stored fuel oil to determine that the new fuel oil, when mixed with previously stored fuel oil, remains acceptable, or to restore the stored fuel oil properties. This restoration may involve feed and bleed procedures, filtering, or combination of these procedures. Even if a DG start and load was required during this time interval and the fuel oil properties were outside limits, there is high likelihood that the DG would still be capable of performing its intended function.

E.1

With required starting air receiver pressure < 225 psig, sufficient capacity for five successive DG normal starts does not exist. However, as long as the receiver pressure is > 150 psig, there is adequate capacity for at least one start attempt, and the DG can be considered OPERABLE while

(continued)

BASES

ACTIONS

E.1 (continued)

the air receiver pressure is restored to the required limit. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the DG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most DG starts are accomplished on the first attempt, and the low probability of an event during this brief period.

F.1

With a Required Action and associated Completion Time of Condition A, B, C, D, or E not met, or the stored diesel fuel oil, lube oil, or starting air subsystem not within limits for reasons other than addressed by Conditions A through E, the associated DG may be incapable of performing its intended function and must be immediately declared inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate useable inventory of fuel oil in the storage tanks to support each DG's operation of all four DGs for 7 days at the worst case post accident time-dependent load profile. The 7 day period is sufficient time to place both Unit 2 and Unit 3 in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

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

SR 3.8.3.2

This Surveillance ensures that sufficient lubricating oil inventory (combined inventory in the DG lube oil sump, lube oil storage tank, and in the warehouse) is available to support at least 7 days of full load operation for each DG. The 350 gal requirement is conservative with respect to the DG manufacturer's consumption values for the run time of the DG. Implicit in this SR is the requirement to verify the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.2 (continued)

capability to transfer the lube oil from its storage location to the DG to maintain adequate inventory for 7 days of full load operation without the level reaching the manufacturer's recommended minimum level.

A 31 day Frequency is adequate to ensure that a sufficient lube oil supply is onsite, since DG starts and run time are closely monitored by the plant staff.

SR 3.8.3.3

The tests of new fuel oil prior to addition to the storage tanks are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between the sample (and corresponding results) of new fuel and addition of new fuel oil to the storage tanks to exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4057-81 (Ref. 6);

b. Verify in accordance with the tests specified in ASTM D975-81 (Ref. 6) as discussed in Reference 7 that the sample has a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes (if specific gravity was not determined by comparison with the supplier's certification), and a flash point of ≥ 125°F;

c. Verify in accordance with tests specified in ASTM D1298-80 (Ref. 6) as discussed in Reference 7 that the sample has an absolute specific gravity at 60/60°F of ≥ 0.83 and ≤ 0.89 , or an absolute specific gravity of within 0.0016 at 60/60°F when compared to the supplier's certificate, or an API gravity at 60°F of ≥ 27° and ≤ 39°, or an API gravity of within 0.3° at 60°F when compared to the supplier's certification; and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

d. Verify that the new fuel oil has a clear and bright appearance with proper color when tested in accordance with ASTM D4176-82 (Ref. 6) as discussed in Reference 7; or verify, in accordance with ASTM D975-81 (Ref. 6), that the sample has a water and sediment content ≤ 0.05 volume percent when dyes have been intentionally added to fuel oil (for example due to sulfur content).

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

Following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-81 (Ref. 6) are met for new fuel oil when tested in accordance with ASTM D975-81 (Ref. 6) as discussed in Reference 7, except that the analysis for sulfur may be performed in accordance with ASTM D1552-79 (Ref. 6) or ASTM D2622-82 (Ref. 6) as discussed in Reference 7. These additional analyses are required by Specification 5.5.9, "Diesel Fuel Oil Testing Program," to be performed within 31 days following sampling and addition. This 31 day requirement is intended to assure that: 1) the new fuel oil sample taken is no more than 31 days old at the time of adding the new fuel oil to the DG storage tank, and 2) the results of the new fuel oil sample are obtained within 31 days after addition of the new fuel oil to the DG storage tank. The 31 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate effect on DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs.

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

Particulate concentrations should be determined in accordance with ASTM D2276-78 (Ref. 6), Method A, as discussed in Reference 7 except that the filters specified

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

in ASTM D2276-78, (Sections 3.1.6 and 3.1.7) may have a nominal pore size up to three microns. This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing. For the Peach Bottom Atomic Power Station design in which the total volume of stored fuel oil is contained in four interconnected tanks, each tank must be considered and tested separately.

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

SR 3.8.3.4

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each DG is available. The system design requirements provide for a minimum of five normal engine starts without recharging. The pressure specified in this SR is intended to reflect the lowest value at which the five starts can be accomplished.

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

SR 3.8.3.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel storage tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.5 (continued)

breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are consistent with Regulatory Guide 1.137 (Ref. 2). This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during performance of the Surveillance.

REFERENCES

1. UFSAR, Section 8.5.2.
2. Regulatory Guide 1.137, Revision 1.
3. ANSI N195, 1976.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 14.
6. ASTM Standards: D4057-81; D975-81; D1298-80; D4176-82; D1552-79; D2622-82; and D2276-78.
7. Letter from G.A. Hunger (PECO Energy) to USNRC Document Control Desk; Peach Bottom Atomic Power Station Units 2 and 3, Supplement 7 to TSCR 93-16, Conversion to Improved Technical Specifications; dated May 24, 1995.

B

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources—Operating

BASES

BACKGROUND

The DC electrical power system provides the AC emergency power system with control power. It also provides a source of reliable, uninterruptible 125/250 VDC power and 125 VDC control power and instrument power to Class 1E and non-Class 1E loads during normal operation and for safe shutdown of the plant following any plant design basis event or accident as documented in the UFSAR (Ref. 1), independent of AC power availability. The DC Electrical Power System meets the intent of the Proposed IEEE Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations (Ref. 2). The DC electrical power system is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure.

The DC power sources provide both motive and control power, and instrument power, to selected safety related equipment, as well as to the nonsafety related equipment. There are two independent divisions per unit, designated Division I and Division II. Each division consists of two 125 VDC batteries. The two 125 VDC batteries in each division are connected in series. Each 125 VDC battery has two chargers (one normally inservice charger and one spare charger) that are exclusively associated with that battery and cannot be interconnected with any other 125 VDC battery. The chargers are supplied from separate 480 V motor control centers (MCCs). Each of these MCCs is connected to an independent emergency AC bus. Some of the chargers are capable of being supplied by Unit 2 MCCs, which receive power from a 4 kV emergency bus, via manual transfer switches. However, for a required battery charger to be considered OPERABLE when the unit is in MODE 1, 2, or 3, it must receive power from its associated Unit 3 MCC. The safety related loads between the 125/250 VDC subsystem are not transferable except for the Automatic Depressurization System (ADS) valves and logic circuits and the main steam safety/relief valves. The ADS logic circuits and valves and the main steam safety/relief valves are normally fed from the Division I DC system.

(continued)

BASES

BACKGROUND (continued)

During normal operation, the DC loads are powered from the battery chargers with the batteries floating on the system. In case of loss of normal power to the battery charger, the DC loads are powered from the batteries.

The DC power distribution system is described in more detail in Bases for LCO 3.8.7, "Distribution System—Operating," and LCO 3.8.8, "Distribution System—Shutdown."

Each battery has adequate storage capacity to carry the required load continuously for approximately 2 hours.

Each of the unit's two DC electrical power divisions, consisting of two 125 V batteries in series, four battery chargers (two normally inservice chargers and two spare chargers), and the corresponding control equipment and interconnecting cabling, is separately housed in a ventilated room apart from its chargers and distribution centers. Each division is separated electrically from the other division to ensure that a single failure in one division does not cause a failure in a redundant division. There is no sharing between redundant Class 1E divisions such as batteries, battery chargers, or distribution panels.

The batteries for DC electrical power subsystems are sized to produce required capacity at 80% of nameplate rating, corresponding to warranted capacity at end of life cycles and the 100% design demand. The minimum design voltage for sizing the battery using the methodology in IEEE 485 (Ref. 3) is based on a traditional 1.81 volts per cell at the end of a 2 hour load profile. The battery terminal voltage using 1.81 volts per cell is 105 V. Using the LOOP/LOCA load profile, the predicted value of the battery terminals is greater than 105 VDC at the end of the profile. Many 1E loads operate exclusively at the beginning of the profile and require greater than the design minimum terminal voltage. The analyzed voltage of the distribution panels and the MCCs is greater than that required during the LOOP/LOCA to support the operation of the 1E loads during the time period they are required to operate.

Each required battery charger of DC electrical power subsystem has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery

(continued)

BASES

BACKGROUND (continued)

bank fully charged. Each battery charger has sufficient capacity to restore the battery from the design minimum charge to its fully charged state within 20 hours while supplying normal steady state loads following a LOCA coincident with a loss of offsite power.

A description of the Unit 2 DC power sources is provided in the Bases for Unit 2 LCO 3.8.4, "DC Sources—Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 14 (Ref. 1), assume that Engineered Safety Feature (ESF) systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation. The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining DC sources OPERABLE during accident conditions in the event of:

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

b. A worst case single failure.

The DC sources satisfy Criterion 3 of the NRC Policy Statement.

LCO

The Unit 3 Division I and Division II DC electrical power subsystems, with each DC subsystem consisting of two 125 V station batteries in series, two battery chargers (one per battery), and the corresponding control equipment and interconnecting cabling supplying power to the associated bus, are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an abnormal operational transient or a postulated DBA. In addition, DC control power (which provides control power for the 4 kV load circuit breakers and the feeder breakers to the 4 kV emergency bus) for two of the four 4 kV emergency buses, as well as control power for two of the diesel generators, is provided by the Unit 2 DC electrical power subsystems. Therefore, Unit 2 Division I and Division II DC electrical power subsystems are also required to be OPERABLE. A Unit 2

(continued)

BASES

LCO (continued)

DC electrical power subsystem OPERABILITY requirements are the same as those required for a Unit 3 DC electrical power subsystem, except that the Unit 2: 1) Division I DC electrical power subsystem is allowed to consist of only the 125 V battery A, an associated battery charger, and the corresponding control equipment and interconnecting cabling supplying 125 V power to the associated bus; and 2) Division II DC electrical power subsystem is allowed to consist of only the 125 V battery B, an associated battery charger, and the corresponding control equipment and interconnecting cabling supplying 125 V power to the associated bus. This exception is allowed only if all 250 VDC loads are removed from the associated bus. In addition, a Unit 2 battery charger can be powered from a Unit 3 AC source, (as described in the Background section of the Bases for Unit 2 LCO 3.8.4, "DC Sources—Operating"), and be considered OPERABLE for the purposes of meeting this LCO. Thus, loss of any DC electrical power subsystem does not prevent the minimum safety function from being performed.

APPLICABILITY

The DC electrical power sources are required to be OPERABLE in MODES 1, 2, and 3 to ensure safe unit operation and to ensure that:

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

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

The DC electrical power requirements for MODES 4 and 5 are addressed in LCO 3.8.5, "DC Sources— Shutdown."

ACTIONS

A.1

Pursuant to LCO 3.0.6, the Distribution Systems—Operating ACTIONS would not be entered even if the DC electrical power subsystem inoperability resulted in de-energization of an AC or DC bus. Therefore, the Required Actions of Condition A are modified by a Note to indicate that when Condition A

(continued)

BASES

ACTIONS

A.1 (continued)

results in de-energization of a Unit 3 4 kV emergency bus or a Unit 2 DC bus, Actions for LCO 3.8.7 must be immediately entered. This allows Condition A to provide requirements for the loss of a Unit 2 DC electrical power subsystem (due to performance of SR 3.8.4.7 or SR 3.8.4.8) without regard to whether a bus is de-energized. LCO 3.8.7 provides the appropriate restriction for a de-energized bus.

If one Unit 2 DC electrical power subsystem is inoperable due to performance of SR 3.8.4.7 or SR 3.8.4.8, the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. In the case of an inoperable Unit 2 DC electrical power subsystem, since a subsequent postulated worst case single failure could result in the loss of safety function, continued power operation should not exceed 7 days. The 7 day Completion Time is based upon the Unit 2 DC electrical power subsystem being inoperable due to performance of SR 3.8.4.7 or SR 3.8.4.8. Performance of these two SRs will result in inoperability of the Unit 2 DC divisional batteries since these batteries are needed for Unit 3 operation, more time is provided to restore the batteries, if the batteries are inoperable for performance of required Surveillances, to preclude the need for a dual unit shutdown to perform these Surveillances. The Unit 2 DC electrical power subsystems also do not provide power to the same type of equipment as the Unit 3 DC sources. The Completion Time also takes into account the capacity and capability of the remaining DC sources.

B.1

Pursuant to LCO 3.0.6, the Distribution Systems—Operating ACTIONS would not be entered even if the DC electrical power subsystem inoperability resulted in de-energization of an AC bus. Therefore, the Required Actions of Condition A are modified by a Note to indicate that when Condition A results in de-energization of a Unit 3 4 kV emergency bus, Actions for LCO 3.8.7 must be immediately entered. This allows Condition A to provide requirements for the loss of a Unit 2 DC electrical power subsystem without regard to whether a bus is de-energized. LCO 3.8.7 provides the appropriate restriction for a de-energized bus.

(continued)

BASES

ACTIONS

B.1 (continued)

If one of the Unit 2 DC electrical power subsystems is inoperable for reasons other than Condition A, the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate the accident condition. Since a subsequent worst case single failure could, however, result in a loss of minimum necessary DC electrical subsystems to mitigate a worst case accident, continued power operation should not exceed 12 hours. The 12 hour Completion Time reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and takes into consideration the importance of the Unit 2 DC electrical power subsystem.

C.1

Condition C represents one Unit 3 division with a loss of ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation. It is therefore imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for complete loss of DC power.

If one of the Unit 3 DC electrical power subsystems is inoperable (e.g., inoperable battery/batteries, inoperable required battery charger/chargers, or inoperable required battery charger/chargers and associated battery/batteries), the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure could result in the loss of minimum necessary DC electrical subsystems to mitigate a worst case accident, continued power operation should not exceed 2 hours. The 2 hour Completion Time is consistent with Regulatory Guide 1.93 (Ref. 4) and reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power division and, if the Unit 3 DC electrical power division is not restored to OPERABLE status, to prepare to initiate an orderly and safe unit shutdown. The 2 hour limit is also consistent with the allowed time for an inoperable Unit 3 DC Distribution System division.

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BASES

ACTIONS (continued)

D.1 and D.2

If the DC electrical power subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 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. The Completion Time to bring the unit to MODE 4 is consistent with the time specified in Regulatory Guide 1.93 (Ref. 4).

E.1

Condition E corresponds to a level of degradation in the DC electrical power subsystems that causes a required safety function to be lost. When more than one DC source is lost, this results in a loss of a required function, thus the plant is in a condition outside the accident analysis. Therefore, no additional time is justified for continued operation. LCO 3.0.3 must be entered immediately to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

As Noted at the beginning of the SRs, SR 3.8.4.1 through SR 3.8.4.8 are applicable only to the Unit 3 DC electrical power subsystems and SR 3.8.4.9 is applicable only to the Unit 2 DC electrical power subsystems.

SR 3.8.4.1

Verifying battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the charging system and the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery (or battery cell) and maintain the battery (or a battery cell) in a fully charged state. The voltage requirements are

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1 (continued)

based on the minimum cell voltage that will maintain a charged cell. This is consistent with the assumptions in the battery sizing calculations. The SR must be performed every 7 days, unless (as specified by the Note in the Frequency) the battery is on equalize charge or has been on equalize charge any time during the previous 1 day. This allows the routine 7 day Frequency to be extended until such a time that the SR can be properly performed and meaningful results obtained. The 14 day Frequency is not modified by the Note, thus regardless of how often the battery is placed on equalize charge, the SR must be performed every 14 days.

SR 3.8.4.2

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

The battery connection resistance limits are established to maintain connection resistance as low as reasonably possible to minimize the overall voltage drop across the battery, and the possibility of battery damage due to heating of connections.

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

SR 3.8.4.3

Visual inspection of the battery cells, cell plates, and battery racks provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance. The presence of physical damage or deterioration does not necessarily represent a failure of

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.3 (continued)

this SR, provided an evaluation determines that the physical damage or deterioration does not affect the OPERABILITY of the battery (its ability to perform its design function).

The 12 month Frequency for these SRs is consistent with IEEE-450 (Ref. 5), which recommends detailed visual inspection of cell condition and rack integrity on a yearly basis.

SR 3.8.4.4 and SR 3.8.4.5

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

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

The battery connection resistance limits are established to maintain connection resistance as low as reasonably possible to minimize the overall voltage drop across the battery, and the possibility of battery damage due to heating of connections.

The 12 month Frequency of these SRs is consistent with IEEE-450 (Ref. 5), which recommends detailed visual inspection of cell condition and inspection of cell to cell and terminal connection resistance on a yearly basis.

SR 3.8.4.6

Battery charger capability requirements are based on the design capacity of the chargers. The minimum charging capacity requirement is based on the capacity to maintain the associated battery in its fully charged condition, and

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.6 (continued)

to restore the battery to its fully charged condition following the worst case design discharge while supplying normal steady state loads. The minimum required amperes and duration ensures that these requirements can be satisfied.

The Frequency is acceptable, given battery charger reliability and the administrative controls existing to ensure adequate charger performance during these 24 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

SR 3.8.4.7

A battery service test is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC Electrical Power System. The discharge rate and test length corresponds to the design duty cycle requirements.

The Frequency is acceptable, given the unit conditions required to perform the test and the other requirements existing to ensure adequate battery performance during these 24 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

This SR is modified by two Notes. Note 1 allows performance of either a modified performance discharge test or a performance discharge test (described in the Bases for SR 3.8.4.8) in lieu of a service test once per 60 months provided the test performed envelops the duty cycle of the battery. This substitution is acceptable because as long as the test current is greater than or equal to the actual duty cycle of the battery, SR 3.8.4.8 represents a more severe test of battery capacity than a service test. In addition, since PBAPS refueling outage cycle is 24 months, SR 3.8.4.8 is performed every 48 months to ensure the 60 month Frequency is met. Therefore, SR 3.8.4.8 is performed in lieu of SR 3.8.4.7 every second refueling outage.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.7 (continued)

The reason for Note 2 is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the Electrical Distribution System, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance.

SR 3.8.4.8

A battery performance discharge test is a test of the constant current capacity of a battery, performed between 3 and 30 days after an equalize charge of the battery, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

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

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

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.8; however, the discharge test may be

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.8 (continued)

used to satisfy SR 3.8.4.8 while satisfying the requirements of SR 3.8.4.7 at the same time only if the test envelops the duty cycle of the battery.

The acceptance criteria for this Surveillance is consistent with IEEE-450 (Ref. 5) and IEEE-485 (Ref. 3). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements.

The Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturers rating, the Surveillance Frequency is reduced to 12 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's rating. Degradation is indicated, according to IEEE-450 (Ref. 5), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is 10% below the manufacturer's rating. If the rate of discharge varies significantly from the previous discharge test, the absolute battery capacity may change significantly, resulting in a capacity drop exceeding the criteria specified above. This absolute battery capacity change could be a result of acid concentration in the plate material, which is not an indication of degradation. Therefore, results of tests with significant rate differences should be discussed with the vendor and evaluated to determine if degradation has occurred. All these Frequencies, with the exception of the 24 month Frequency, are consistent with the recommendations in IEEE-450 (Ref. 5). The 24 month Frequency is acceptable, given the battery has shown nc signs of degradation, the unit conditions required to perform the test and other requirements existing to ensure battery performance during these 24 month intervals. In addition, the 24 month Frequency is intended to be consistent with expected fuel cycle lengths. A

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.8 (continued)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance. The DC batteries of the other unit are exempted from this restriction since they are required to be OPERABLE by both units and the Surveillance cannot be performed in the manner required by the Note without resulting in a dual unit shutdown.

SR 3.8.4.9

With the exception of this Surveillance, all other Surveillances of this Specification (SR 3.8.4.1 through SR 3.8.4.8) are applied only to the Unit 3 DC electrical power subsystems. This Surveillance is provided to direct that the appropriate Surveillances for the required Unit 2 DC electrical power subsystems are governed by the Unit 2 Technical Specifications. Performance of the applicable Unit 2 Surveillances will satisfy Unit 2 requirements, as well as satisfying this Unit 3 Surveillance Requirement.

The Frequency required by the applicable Unit 2 SR also governs performance of that SR for Unit 3. As Noted, if Unit 2 is in MODE 4 or 5, or moving irradiated fuel assemblies in the secondary containment, the Note to Unit 2 SR 3.8.5.1 is applicable. This ensures that a Unit 3 SR will not require a Unit 2 SR to be performed, when the Unit 2 Technical Specifications exempts performance of a Unit 2 SR. (However, as stated in the Unit 2 SR 3.8.5.1 Note, while performance of the SR is exempted, the SR still must be met.)

REFERENCES

1. UFSAR, Chapter 14.

2. "Proposed IEEE Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations," June 1969.

3. IEEE Standard 485, 1983.

(continued)

BASES

REFERENCES (continued)	4.	Regulatory Guide 1.93, December 1974.
	5.	IEEE Standard 450, 1987.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 DC Sources—Shutdown

BASES

BACKGROUND	A description of the DC sources is provided in the Bases for LCO 3.8.4, "DC Sources—Operating."
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident and transient analyses in the UFSAR, Chapter 14 (Ref. 1), assume that Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the diesel generators (DGs), emergency auxiliaries, and control and switching during all MODES of operation. The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY. The OPERABILITY of the minimum DC electrical power sources during MODES 4 and 5 and during movement of irradiated fuel assemblies in secondary containment ensures that: a. The facility can be maintained in the shutdown or refueling condition for extended periods; b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and c. Adequate DC electrical power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident. The DC sources satisfy Criterion 3 of the NRC Policy Statement.
LCO	The Unit 3 DC electrical power subsystems, with each DC subsystem consisting of two 125 V station batteries in series, two battery chargers (one per battery), and the corresponding control equipment and interconnecting cabling supplying power to the associated bus, are required to be

(continued)

BASES

LCO (continued)	OPERABLE to support Unit 3 DC distribution subsystems required OPERABLE by LCO 3.8.8, "Distribution Systems—Shutdown." When the equipment required OPERABLE: 1) does not require 250 VDC from the DC electrical power subsystem; and 2) does not require 125 VDC from one of the two 125 V batteries of the DC electrical power subsystem, the Unit 3 DC electrical power subsystem requirements can be modified to only include one 125 V battery (the battery needed to provide power to required equipment), an associated battery charger, and the corresponding control equipment and interconnecting cabling supplying 125 V power to the associated bus. This exception is allowed only if all 250 VDC loads are removed from the associated bus. In addition, DC control power (which provides control power for the 4 kV load circuit breakers and the feeder breakers to the 4 kV emergency bus) for two of the four 4 kV emergency buses, as well as control power for two of the diesel generators, is provided by the Unit 2 DC electrical power subsystems. Therefore, the Unit 2 DC electrical power subsystems needed to support required components are also required to be OPERABLE. The Unit 2 DC electrical power subsystem OPERABILITY requirements are the same as those required for a Unit 3 DC electrical power subsystem. In addition, battery chargers (Unit 2 and Unit 3) can be powered from the opposite unit's AC source (as described in the Background section of the Bases for LCO 3.8.4, "DC Sources—Operating"), and be considered OPERABLE for the purpose of meeting this LCO. This requirement ensures the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and inadvertent reactor vessel draindown).
APPLICABILITY	The DC electrical power sources required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment provide assurance that: a. Required features to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core in case of an inadvertent draindown of the reactor vessel;

(continued)

BASES

APPLICABILITY (continued)

b. Required features needed to mitigate a fuel handling accident are available;

c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The DC electrical power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.4.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown. 8

A.1, A.2.1, A.2.2, A.2.3, and A.2.4

If more than one DC distribution subsystem is required according to LCO 3.8.8, the DC electrical power subsystems remaining OPERABLE with one or more DC electrical power subsystems inoperable may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel.

By allowance of the option to declare required features inoperable with associated DC electrical power subsystems inoperable, appropriate restrictions are implemented in accordance with the affected system LCOs' ACTIONS. However, in many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in secondary containment, and any activities that could result in inadvertent draining of the reactor vessel).

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4 (continued)

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required DC electrical power subsystems and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required DC electrical power subsystems should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 requires performance of all Surveillances required by SR 3.8.4.1 through SR 3.8.4.8. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC electrical power subsystems from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

SR 3.8.5.2

This Surveillance is provided to direct that the appropriate Surveillances for the required Unit 2 DC electrical power subsystems are governed by the Unit 2 Technical Specifications. Performance of the applicable Unit 2 Surveillances will satisfy Unit 2 requirements, as well as satisfying this Unit 3 Surveillance Requirement. The Frequency required by the applicable Unit 2 SR also governs performance of that SR for Unit 3.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.8.5.2 (continued) As Noted, if Unit 2 is in MODE 4 or 5, or moving irradiated fuel assemblies in the secondary containment, the Note to Unit 2 SR 3.8.5.1 is applicable. This ensures that a Unit 3 SR will not require a Unit 2 SR to be performed, when the Unit 2 Technical Specifications exempts performance of a Unit 2 SR. (However, as stated in the Unit 2 SR 3.8.5.1 Note, while performance of an SR is exempted, the SR still must be met.)
REFERENCES	1. UFSAR, Chapter 14.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Cell Parameters

BASES

BACKGROUND	This LCO delineates the limits on electrolyte temperature, level, float voltage, and specific gravity for the DC electrical power subsystems batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.4, "DC Sources—Operating," and LCO 3.8.5, "DC Sources—Shutdown."
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident (DBA) and transient analyses in UFSAR, Chapter 14 (Ref. 1), assume Engineered Safety Feature systems are OPERABLE. The DC electrical power subsystems provide normal and emergency DC electrical power for the diesel generators (DGs), emergency auxiliaries, and control and switching during all MODES of operation. The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit as discussed in the Bases of LCO 3.8.4, "DC Sources—Operating," and LCO 3.8.5, "DC Sources—Shutdown. A Since battery cell parameters support the operation of the DC electrical power subsystems, they satisfy Criterion 3 of the NRC Policy Statement.
LCO	Battery cell parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an abnormal operational transient or a postulated DBA. Electrolyte limits are conservatively established, allowing continued DC electrical system function even with Category A and B limits not met.
APPLICABILITY	The battery cell parameters are required solely for the support of the associated DC electrical power subsystem. Therefore, these cell parameters are only required when the DC power source is required to be OPERABLE. Refer to the Applicability discussions in Bases for LCO 3.8.4 and LCO 3.8.5.

(continued)

BASES (continued)

ACTIONS

A.1, A.2, and A.3

With parameters of one or more cells in one or more batteries not within limits (i.e., Category A limits not met or Category B limits not met, or Category A and B limits not met) but within the Category C limits specified in Table 3.8.6-1, the battery is degraded but there is still sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of Category A or B limits not met, and continued operation is permitted for a limited period.

The pilot cell electrolyte level and float voltage are required to be verified to meet the Category C limits within 1 hour (Required Action A.1). This check provides a quick indication of the status of the remainder of the battery cells. One hour provides time to inspect the electrolyte level and to confirm the float voltage of the pilot cells. One hour is considered a reasonable amount of time to perform the required verification.

Verification that the Category C limits are met (Required Action A.2) provides assurance that during the time needed to restore the parameters to the Category A and B limits, the battery is still capable of performing its intended function. A period of 24 hours is allowed to complete the initial verification because specific gravity measurements must be obtained for each connected cell. Taking into consideration both the time required to perform the required verification and the assurance that the battery cell parameters are not severely degraded, this time is considered reasonable. The verification is repeated at 7 day intervals until the parameters are restored to Category A or B limits. This periodic verification is consistent with the normal Frequency of pilot cell surveillances.

Continued operation is only permitted for 31 days before battery cell parameters must be restored to within Category A and B limits. Taking into consideration that, while battery capacity is degraded, sufficient capacity exists to perform the intended function and to allow time to fully restore the battery cell parameters to normal limits, this time is acceptable for operation prior to declaring the DC batteries inoperable.

(continued)

BASES

ACTIONS (continued)

B.1

When any battery parameter is outside the Category C limit for any connected cell, sufficient capacity to supply the maximum expected load requirement is not ensured and the corresponding DC electrical power subsystem must be declared inoperable. Additionally, other potentially extreme conditions, such as not completing the Required Actions of Condition A within the required Completion Time or average electrolyte temperature of representative cells falling below 40°F, also are cause for immediately declaring the associated DC electrical power subsystem inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

This SR verifies that Category A battery cell parameters are consistent with IEEE-450 (Ref. 2), which recommends regular battery inspections (at least one per month) including voltage, specific gravity, and electrolyte temperature of pilot cells. The SR must be performed every 7 days, unless (as specified by the Note in the Frequency) the battery is on equalize charge or has been on equalize charge any time during the previous 4 days. This allows the routine 7 day Frequency to be extended until such a time that the SR can be properly performed and meaningful results obtained. The 14 day Frequency is not modified by the Note, thus regardless of how often the battery is placed on equalize charge, the SR must be performed every 14 days.

SR 3.8.6.2

The quarterly inspection of specific gravity and voltage is consistent with IEEE-450 (Ref. 2). In addition, within 24 hours of a battery discharge < 100 V or within 24 hours of a battery overcharge > 145 V, the battery must be demonstrated to meet Category B limits. Transients, such as motor starting transients which may momentarily cause battery voltage to drop to ≤ 100 V, do not constitute battery discharge provided the battery terminal voltage and float current return to pre-transient values. This inspection is also consistent with IEEE-450 (Ref. 2), which recommends special inspections following a severe discharge or overcharge, to ensure that no significant degradation of the battery occurs as a consequence of such discharge or overcharge.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.6.3

This Surveillance verification that the average temperature of representative cells is within limits is consistent with a recommendation of IEEE-450 (Ref. 2) that states that the temperature of electrolytes in representative cells should be determined on a quarterly basis.

Lower than normal temperatures act to inhibit or reduce battery capacity. This SR ensures that the operating temperatures remain within an acceptable operating range.

Table 3.8.6-1

This table delineates the limits on electrolyte level, float voltage, and specific gravity for three different categories. The meaning of each category is discussed below.

Category A defines the normal parameter limit for each designated pilot cell in each battery. The cells selected as pilot cells are those whose temperature, voltage, and electrolyte specific gravity approximate the state of charge of the entire battery.

The Category A limits specified for electrolyte level are based on manufacturer's recommendations and are consistent with the guidance in IEEE-450 (Ref. 2), with the extra ½ inch allowance above the high water level indication for operating margin to account for temperature and charge effects. In addition to this allowance, footnote a to Table 3.8.6-1 permits the electrolyte level to be above the specified maximum level during equalizing charge, provided it is not overflowing. These limits ensure that the plates suffer no physical damage, and that adequate electron transfer capability is maintained in the event of transient conditions. IEEE-450 (Ref. 2) recommends that electrolyte level readings should be made only after the battery has been at float charge for at least 72 hours.

The Category A limit specified for float voltage is ≥ 2.13 V per cell. This value is based on the recommendation of IEEE-450 (Ref. 2), which states that prolonged operation of cells below 2.13 V can reduce the life expectancy of cells. The Category A limit specified for specific gravity for each pilot cell is ≥ 1.195 (0.020 below the manufacturer's fully

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

charged nominal specific gravity or a battery charging current that had stabilized at a low value). This value is characteristic of a charged cell with adequate capacity. According to IEEE-450 (Ref. 2), the specific gravity readings are based on a temperature of 77°F (25°C).

The specific gravity readings are corrected for actual electrolyte temperature and level. For each 3°F (1.67°C) above 77°F (25°C), 1 point (0.001) is added to the reading; 1 point is subtracted for each 3°F below 77°F. The specific gravity of the electrolyte in a cell increases with a loss of water due to electrolysis or evaporation. Level correction will be in accordance with manufacturer's recommendations.

Category B defines the normal parameter limits for each connected cell. The term "connected cell" excludes any battery cell that may be jumpered out.

The Category B limits specified for electrolyte level and float voltage are the same as those specified for Category A and have been discussed above. The Category B limit specified for specific gravity for each connected cell is ≥ 1.195 (0.020 below the manufacturer's fully charged, nominal specific gravity) with the average of all connected cells 1.205 (0.010 below the manufacturer's fully charged, nominal specific gravity). These values were developed from manufacturer's recommendations. The minimum specific gravity value required for each cell ensures that the effects of a highly charged or newly installed cell do not mask overall degradation of the battery.

Category C defines the limit for each connected cell. These values, although reduced, provide assurance that sufficient capacity exists to perform the intended function and maintain a margin of safety. When any battery parameter is outside the Category C limit, the assurance of sufficient capacity described above no longer exists, and the battery must be declared inoperable.

The Category C limit specified for electrolyte level (above the top of the plates and not overflowing) ensure that the plates suffer no physical damage and maintain adequate electron transfer capability. The Category C Allowable Value for voltage is based on IEEE-450 (Ref. 2), which

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

states that a cell voltage of 2.07 V or below, under float conditions and not caused by elevated temperature of the cell, indicates internal cell problems and may require cell replacement.

The Category C limit of average specific gravity ≥ 1.190, is based on manufacturer's recommendations. In addition to that limit, it is required that the specific gravity for each connected cell must be no less than 0.020 below the average of all connected cells. This limit ensures that the effect of a highly charged or new cell does not mask overall degradation of the battery.

The footnotes to Table 3.8.6-1 that apply to specific gravity are applicable to Category A, B, and C specific gravity. Footnote b of Table 3.8.6-1 requires the above mentioned correction for electrolyte level and temperature, with the exception that level correction is not required when battery charging current, while on float charge, is < 1 amp. This current provides, in general, an indication of overall battery condition.

Because of specific gravity gradients that are produced during the recharging process, delays of several days may occur while waiting for the specific gravity to stabilize. A stabilized charger current is an acceptable alternative to specific gravity measurement for determining the state of charge of the designated pilot cell. This phenomenon is discussed in IEEE-450 (Ref. 2). Footnote c to Table 3.8.6-1 allows the float charge current to be used as an alternate to specific gravity for up to 180 days following a battery recharge after a deep discharge. Within 180 days each connected cell's specific gravity must be measured to confirm the state of charge. Following a minor battery recharge (such as equalizing charge that does not follow a deep discharge) specific gravity gradients are not significant, and confirming measurements must be made within 30 days.

REFERENCES

1. UFSAR, Chapter 14.

2. IEEE Standard 450, 1987.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Distribution Systems—Operating

BASES

BACKGROUND

The onsite Class 1E AC and DC electrical power distribution system is divided into redundant and independent AC and DC electrical power distribution subsystems.

The primary AC distribution system for Unit 3 consists of four 4 kV emergency buses each having two offsite sources of power as well as an onsite diesel generator (DG) source. Each 4 kV emergency bus is connected to its normal source of power via either emergency auxiliary transformer no. 2 or no. 3. During a loss of the normal supply of offsite power to the 4 kV emergency buses, the alternate supply breaker from the alternate supply of offsite power for the 4 kV emergency buses attempts to close. If all offsite sources are unavailable, the onsite emergency DGs supply power to the 4 kV emergency buses. (However, these supply breakers are not governed by this LCO; they are governed by LCO 3.8.1, "AC Sources—Operating".) B

The secondary plant distribution system for Unit 3 includes 480 VAC load centers E134, E234, E334, and E434.

There are two independent 125/250 VDC electrical power distribution subsystems for Unit 3 that support the necessary power for ESF functions.

In addition, since some components required by Unit 3 receive power through Unit 2 electrical power distribution subsystems, the Unit 2 AC and DC electrical power distribution subsystems needed to support the required equipment are also addressed in LCO 3.8.7. A description of the Unit 2 AC and DC Electrical Power Distribution System is provided in the Bases for Unit 2 LCO 3.8.7, "Distribution System—Operating."

The list of required Unit 3 distribution buses is presented in Table B 3.8.7-1.

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BASES (continued)

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 14 (Ref. 1), assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC and DC electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6 Containment Systems.

The OPERABILITY of the AC and DC electrical power distribution subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining distribution systems OPERABLE during accident conditions in the event of:

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

b. A postulated worst case single failure.

The AC and DC electrical power distribution system satisfies Criterion 3 of the NRC Policy Statement.

LCO

The Unit 3 AC and DC electrical power distribution subsystems are required to be OPERABLE. The required Unit 3 electrical power distribution subsystems listed in Table B 3.8.7-1 ensure the availability of AC and DC electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an abnormal operational transient or a postulated DBA. As stated in the Table, each division of the AC and DC electrical power distribution systems is a subsystem. In addition, since some components required by Unit 3 receive power through Unit 2 electrical power distribution subsystems (e.g., Containment Atmospheric Dilution (CAD) System, Standby Gas Treatment (SGT) System, Emergency Service Water System, Main Control Room Emergency Ventilation (MCREV) System, and DC control power for two of the four 4 kV emergency buses, as well as control power for

(continued)

BASES

LCO (continued)

two of the diesel generators), the Unit 2 AC and DC electrical power distribution subsystems needed to support the required equipment must also be OPERABLE. The Unit 2 electrical power distribution subsystems that may be required are listed in Unit 2 Table B 3.8.7-1.

Maintaining the Unit 3 Division I and II and required Unit 2 AC and DC electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Therefore, a single failure within any system or within the electrical power distribution subsystems will not prevent safe shutdown of the reactor.

The Unit 2 and Unit 3 AC electrical power distribution subsystems require the associated buses and electrical circuits to be energized to their proper voltages. The Unit 2 and Unit 3 DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated batteries or chargers. However, when a Unit 2 DC electrical power subsystem is only required to have one 125 V battery and associated battery charger to be considered OPERABLE (as described in the LCO section of the Bases for LCO 3.8.4, "DC Sources—Operating"), the proper voltage to which the associated bus is required to be energized is lowered from 250 V to 125 V (as read from the associated battery charger).

Based on the number of safety significant electrical loads associated with each electrical power distribution component (i.e., bus, load center, or distribution panel) listed in Table B 3.8.7-1, if one or more of the electrical power distribution components within a division (listed in Table 3.8.7-1) becomes inoperable, entry into the appropriate ACTIONS of LCO 3.8.7 is required. Other electrical power distribution components, such as motor control centers (MCC) and distribution panels, which help comprise the AC and DC distribution systems are not listed in Table B 3.8.7-1. The loss of electrical loads associated with these electrical power distribution components may not result in a complete loss of a redundant safety function necessary to shut down the reactor and maintain it in a safe condition. Therefore, should one or more of these electrical power distribution components become inoperable due to a failure not affecting the OPERABILITY of an electrical power distribution component listed in Table B 3.8.7-1 (e.g., a breaker

(continued)

BASES

LCO (continued)

supplying a single MCC fails open), the individual loads on the electrical power distribution component would be considered inoperable, and the appropriate Conditions and Required Actions of the LCOs governing the individual loads would be entered. If however, one or more of these electrical power distribution components is inoperable due to a failure also affecting the OPERABILITY of an electrical power distribution component listed in Table B 3.8.7-1 (e.g., loss of a 4 kV emergency bus, which results in de-energization of all electrical power distribution components powered from the 4 kV emergency bus), while these electrical power distribution components and individual loads are still considered inoperable, the Conditions and Required Actions of the LCO for the individual loads are not required to be entered, since LCO 3.0.6 allows this exception (i.e., the loads are inoperable due to the inoperability of a support system governed by a Technical Specification; the 4 kV emergency bus).

In addition, transfer switches between redundant safety related Unit 2 and Unit 3 AC and DC power distribution subsystems must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, which could cause the failure of a redundant subsystem and a loss of essential safety function(s). If any transfer switches are closed, the electrical power distribution subsystem which is not being powered from its normal source (i.e., it is being powered from its redundant electrical power distribution subsystem) is considered inoperable. This applies to the onsite, safety related, redundant electrical power distribution subsystems. It does not, however, preclude redundant Class 1E 4 kV emergency buses from being powered from the same offsite circuit.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

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

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

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BASES

APPLICABILITY (continued)

Electrical power distribution subsystem requirements for MODES 4 and 5 and other conditions in which AC and DC electrical power distribution subsystems are required, are covered in LCO 3.8.8, "Distribution Systems—Shutdown."

ACTIONS

A.1

Pursuant to LCO 3.0.6, the DC Sources—Operating ACTIONS would not be entered even if the AC electrical power distribution subsystem inoperability resulted in de-energization of a required battery charger. Therefore, the Required Actions of Condition A are modified by a Note to indicate that when Condition A results in de-energization of a required Unit 2 battery charger, Actions for LCO 3.8.4 must be immediately entered. This allows Condition A to provide requirements for the loss of a Unit 2 AC electrical power distribution subsystem without regard to whether a battery charger is de-energized. LCO 3.8.4 provides the appropriate restriction for a de-energized battery charger.

If one or more of the required Unit 2 AC electrical power distribution subsystems are inoperable, and a loss of function has not occurred as described in Condition F, the remaining AC electrical power distribution subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure could, however, result in the loss of certain safety functions, continued power operation should not exceed 7 days. The 7 day Completion Time takes into account the capacity and capability of the remaining AC electrical power distribution subsystems, and is based on the shortest restoration time allowed for the systems affected by the inoperable AC electrical power distribution subsystem in the respective system Specification.

B.1

If one of the Unit 2 DC electrical power distribution subsystems is inoperable, the remaining DC electrical power distribution subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure could, however, result in the loss of safety function, continued power operation

(continued)

BASES

ACTIONS

B.1 (continued)

should not exceed 12 hours. The 12 hour Completion Time reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power distribution subsystem and takes into consideration the importance of the Unit 2 DC electrical power distribution subsystem.

C.1

With one Unit 3 AC electrical power distribution subsystem inoperable, the remaining AC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the Unit 3 AC electrical power distribution subsystem must be restored to OPERABLE status within 8 hours.

The Condition C worst scenario is one 4 kV emergency bus without AC power (i.e., no offsite power to the 4 kV emergency bus and the associated DG inoperable). In this Condition, the unit is more vulnerable to a complete loss of Unit 3 AC power. It is, therefore, imperative that the unit operators' attention be focused on minimizing the potential for loss of power to the remaining buses by stabilizing the unit, and on restoring power to the affected bus(es). The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because:

a. There is a potential for decreased safety if the unit operators' attention is diverted from the evaluations and actions necessary to restore power to the affected bus(es) to the actions associated with taking the unit to shutdown within this time limit.

b. The potential for an event in conjunction with a single failure of a redundant component in the division with AC power. (The redundant component is verified OPERABLE in accordance with Specification 5.5.11, "Safety Function Determination Program (SFDP).")

(continued)

BASES

ACTIONS

C.1 (continued)

The second Completion Time for Required Action C.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.7.a. If Condition C is entered while, for instance, a Unit 3 DC bus is inoperable and subsequently returned OPERABLE, this LCO may already have been not met for up to 2 hours. This situation could lead to a total duration of 10 hours, since initial failure of the LCO, to restore the Unit 3 AC Electrical Power Distribution System. At this time a Unit 3 DC bus could again become inoperable, and Unit 3 AC Electrical Power Distribution System could be restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This results in establishing the "time zero" at the time LCO 3.8.7.a was initially not met, instead of at the time Condition C was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO 3.8.7.a indefinitely.

D.1

With one Unit 3 DC electrical power distribution subsystem inoperable, the remaining DC electrical power distribution subsystem is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the Unit 3 DC electrical power distribution subsystem must be restored to OPERABLE status within 2 hours.

Condition D represents one Unit 3 electrical power distribution subsystem without adequate DC power, potentially with both the battery(s) significantly degraded and the associated charger(s) nonfunctioning. In this situation the plant is significantly more vulnerable to a complete loss of all Unit 3 DC power. It is, therefore, imperative that the operator's attention focus on

(continued)

BASES

ACTIONS

D.1 (continued)

stabilizing the plant, minimizing the potential for loss of power to the remaining electrical power distribution subsystem, and restoring power to the affected electrical power distribution subsystem.

This 2 hour limit is more conservative than Completion Times allowed for the majority of components that would be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

a. The potential for decreased safety when requiring a change in plant conditions (i.e., requiring a shutdown) while not allowing stable operations to continue;

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

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

The 2 hour Completion Time for DC electrical power distribution subsystems is consistent with Regulatory Guide 1.93 (Ref. 2).

The second Completion Time for Required Action D.1 establishes a limit on the maximum time allowed for any combination of required electrical power distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.7.a. If Condition D is entered while, for instance, a Unit 3 AC bus is inoperable and subsequently restored OPERABLE, LCO 3.8.7.a may already have been not met for up to 8 hours. This situation could lead to a total duration of 10 hours, since initial failure of LCO 3.8.7.a, to restore the Unit 3 DC Electrical Power Distribution System. At this time, a Unit 3 AC bus could again become inoperable, and Unit 3 DC Electrical Power Distribution System could be restored OPERABLE. This could continue indefinitely.

(continued)

BASES

ACTIONS

D.1 (continued)

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This allowance results in establishing the "time zero" at the time LCO 3.8.7.a was initially not met, instead of at the time Condition D was entered. The 16 hour Completion Time is an acceptable limitation on this potential of failing to meet the LCO indefinitely.

E.1 and E.2

If the inoperable electrical power distribution subsystem cannot be restored to OPERABLE status within the associated Completion Time, the unit 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.

F.1

Condition F corresponds to a level of degradation in the electrical power distribution system that causes a required safety function to be lost. When more than one Condition is entered, and this results in the loss of a required function, the plant is in a condition outside the accident analysis. Therefore, no additional time is justified for continued operation. LCO 3.0.3 must be entered immediately to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the AC and DC electrical power distribution systems are functioning properly, with the correct circuit breaker alignment (for the AC electrical power distribution system only). The correct AC breaker alignment ensures the appropriate separation and independence of the electrical buses are maintained, and power is available to each required bus. The verification of indicated power availability on the AC and DC buses

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1 (continued)

ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. This may be performed by verification of absence of low voltage alarms. The 7 day Frequency takes into account the redundant capability of the AC and DC electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. UFSAR, Chapter 14.

2. Regulatory Guide 1.93, December 1974.

Table B 3.8.7-1 (page 1 of 1)
AC and DC Electrical Power Distribution Systems

TYPE	VOLTAGE	DIVISION I*	DIVISION II*
AC buses	4160 V	Emergency Buses E13, E33	Emergency Buses E23, E43
	480 V	Load Centers E134, E334	Load Centers E234, E434
DC buses	250 V	Distribution Panel 3AD18	Distribution Panel 3BD18

* Each division of the AC and DC electrical power distribution systems is a subsystem.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Distribution Systems—Shutdown

BASES

BACKGROUND

A description of the AC and DC electrical power distribution system is provided in the Bases for LCO 3.8.7, "Distribution Systems—Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the UFSAR, Chapter 14 (Ref. 1), assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC and DC electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the AC and DC electrical power distribution system is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum AC and DC electrical power sources and associated power distribution subsystems during MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.

The AC and DC electrical power distribution systems satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

Various combinations of subsystems, equipment, and components are required OPERABLE by other LCOs, depending on the specific plant condition. Implicit in those requirements is the required OPERABILITY of necessary support required features. This LCO explicitly requires energization of the portions of the Unit 3 electrical distribution system necessary to support OPERABILITY of Technical Specifications required systems, equipment, and components—both specifically addressed by their own LCO, and implicitly required by the definition of OPERABILITY. In addition some components that may be required by Unit 3 receive power through Unit 2 electrical power distribution subsystems (e.g., Standby Gas Treatment System, Main Control Room Emergency Ventilation System, and DC control power for two of the four 4 kV emergency buses, as well as control power for two of the diesel generators). Therefore, Unit 2 AC and DC electrical power distribution subsystems needed to support the required equipment must also be OPERABLE.

In addition, it is acceptable for required buses to be cross-tied during shutdown conditions, permitting a single source to supply multiple redundant buses, provided the source is capable of maintaining proper frequency (if required) and voltage.

Maintaining these portions of the distribution system energized ensures the availability of sufficient power to operate the plant in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and inadvertent reactor vessel draindown).

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core in case of an inadvertent draindown of the reactor vessel;

b. Systems needed to mitigate a fuel handling accident are available;

(continued)

BASES

APPLICABILITY (continued)

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The AC and DC electrical power distribution subsystem requirements for MODES 1, 2, and 3 are covered in LCO 3.8.7.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5

Although redundant required features may require redundant electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel. By allowing the option to declare required features inoperable with associated electrical power distribution subsystems inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystem LCO's Required Actions. However, in many instances this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made, (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in the secondary containment, and any activities that could result in inadvertent draining of the reactor vessel).

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5 (continued)

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC and DC electrical power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the plant safety systems.

Notwithstanding performance of the above conservative Required Actions, a required residual heat removal-shutdown cooling (RHR-SDC) subsystem may be inoperable. In this case, Required Actions A.2.1 through A.2.4 do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the RHR-SDC ACTIONS would not be entered. Therefore, Required Action A.2.5 is provided to direct declaring RHR-SDC inoperable, which results in taking the appropriate RHR-SDC ACTIONS.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required electrical power distribution subsystems should be completed as quickly as possible in order to minimize the time the plant safety systems may be without power.

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the AC and DC electrical power distribution subsystem is functioning properly, with the buses energized. The verification of indicated power availability on the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. This may be performed by verification of absence of low voltage alarms. The 7 day Frequency takes into account the redundant capability of the electrical power distribution subsystems, as well as other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. UFSAR, Chapter 14.

BASES

APPLICABLE SAFETY ANALYSES (continued)

dropping an assembly on the RPV flange will result in reduced releases of fission gases. Based on this judgement, and the physical dimensions which preclude normal operation with water level 23 feet above the flange, a slight reduction in this water level (to 20 ft 11 inches above the flange) is acceptable (Ref. 3).

RPV water level satisfies Criterion 2 of the NRC Policy Statement.

LCO

A minimum water level of 458 inches above RPV instrument zero (20 ft 11 inches above the top of the RPV flange) is required to ensure that the radiological consequences of a postulated fuel handling accident are within acceptable limits.

APPLICABILITY

LCO 3.9.6 is applicable when moving fuel assemblies or handling control rods (i.e., movement with other than the normal control rod drive) within the RPV. The LCO minimizes the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis. If irradiated fuel is not present within the RPV, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for fuel handling accidents in the spent fuel storage pool are covered by LCO 3.7.7, "Spent Fuel Storage Pool Water Level."

ACTIONS

A.1

If the water level is < 458 inches above RPV instrument zero, all operations involving movement of fuel assemblies and handling of control rods within the RPV shall be suspended immediately to ensure that a fuel handling accident cannot occur. The suspension of fuel movement and control rod handling shall not preclude completion of movement of a component to a safe position.

(continued)

LIMITING CONDITIONS FOR OPERATION

3.1 Reactor Protection System (RPS)

A. The RPS instrumentation for each trip function in Table 3.1.1 shall be Operable; and, there shall be two Operable or tripped trip systems for each Trip Function.

The designed system response times from the opening of the sensor contact up to and including the opening of the trip actuator contacts shall not exceed 50 milliseconds.

Applicability:

According to Table 3.1.1.

Conditions and Required Actions: (1)(2)

1. With one or more channel(s) required by Table 3.1.1 inoperable in one or more trip functions, place the inoperable channel or associated trip system in trip within 12 hours.

2. With one or more trip functions with one or more channels required by Table 3.1.1 inoperable in both trip systems, place channel in one trip system in trip or place one trip system in trip within 6 hours.

3. With one or more automatic trip functions or two or more manual trip functions (Mode Switch in Shutdown, Manual Scram and RPS Channel Test Switches) with RPS trip capability not maintained, restore RPS trip capability within one hour.

4. If the required actions and associated completion time of Action 1 or 2 or 3 are not met, take the action required by Table 3.1.1 for the Trip Function.

SURVEILLANCE REQUIREMENTS

4.1 Reactor Protection System

A. Each RPS instrument channel shall be demonstrated Operable by performance of a channel functional test and channel calibration at the Frequencies shown in Tables 4.1.1 and 4.1.2, respectively.

The RPS A1 Response time ~~measurements~~ Shall be that time interval (from the opening of the sensor contact up to and including the opening of the trip actuator contacts) are not part of the normal instrument test. The RPS response time of each reactor trip function shall be demonstrated to be within its limits once per operating cycle.

REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME A1

See Discussion of Changes for ITS 3.3.1.1, "RPS Instrumentation"

(1) When a channel is placed in an inoperable status solely for performance of required Surveillances, initiation of these Actions may be delayed for up to 6 hours provided the associated trip function maintains RPS trip capability.

(2) An inoperable channel or trip system need not be placed in the tripped condition where this would cause the trip function to occur. In these cases, if the inoperable channel is not restored to Operable status within the required time, the Action required by Table 3.1.1 for that trip function shall be taken immediately.

Specification 1.0

INSERT B
(Page 2 of 3)

PHYSICS TESTS

PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are:

a. Described in Section 13.5, Startup and Power Test Program of the UFSAR;

b. Authorized under the provisions of 10 CFR 50.59; or

c. Otherwise approved by the Nuclear Regulatory Commission.

~~PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)~~

~~The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.6.6. Plant operation within these operating limits is addressed in LCO 3.4.9, "RCS Pressure and Temperature (P/T) Limits."~~

B

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.

LIMITING CONDITIONS FOR OPERATION

3.1 Reactor Protection System (RPS)

A. The RPS instrumentation for each trip function in Table 3.1.1 shall be Operable; and, there shall be two Operable or tripped trip systems for each Trip Function.

The designed system response times from the opening of the sensor contact up to and including the opening of the trip actuator contacts shall not exceed 50 milliseconds.

Applicability:

According to Table 3.1.1.

Conditions and Required Actions: (1)(2)

1. With one or more channel(s) required by Table 3.1.1 inoperable in one or more trip functions, place the inoperable channel or associated trip system in trip within 12 hours.

2. With one or more trip functions with one or more channels required by Table 3.1.1 inoperable in both trip systems, place channel in one trip system in trip or place one trip system in trip within 6 hours.

3. With one or more automatic trip functions or two or more manual trip functions (Mode Switch in Shutdown, Manual Scram and RPS Channel Test Switches) with RPS trip capability not maintained, restore RPS trip capability within one hour.

4. If the required actions and associated completion time of Action 1 or 2 or 3 are not met, take the action required by Table 3.1.1 for the Trip Function.

SURVEILLANCE REQUIREMENTS

4.1 Reactor Protection System

A. Each RPS instrument channel shall be demonstrated Operable by performance of a channel functional test and channel calibration at the Frequencies shown in Tables 4.1.1 and 4.1.2, respectively.

The RPS A1 shall be test time interval

Response ~~time measurements~~ (from the opening of the sensor contact up to and including the opening of the trip actuator contacts) ~~are not part of the normal instrument~~ test. The RPS response time of each reactor trip function shall be demonstrated to be within its limits once per operating cycle.

REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME

A1

See Discussion of Changes for ITS 3.3.1.1, "RPS Instrumentation"

A1

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(1) When a channel is placed in an inoperable status solely for performance of required Surveillances, initiation of these Actions may be delayed for up to 6 hours provided the associated trip function maintains RPS trip capability.

(2) An inoperable channel or trip system need not be placed in the tripped condition where this would cause the trip function to occur. In these cases, if the inoperable channel is not restored to Operable status within the required time, the Action required by Table 3.1.1 for that trip function shall be taken immediately.

Specification 1.0

INSERT 8
(Page 2 of 3)

PHYSICS TESTS

PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are:

a. Described in Section 13.5, Startup and Power Test Program of the UFSAR;

b. Authorized under the provisions of 10 CFR 50.59; or

c. Otherwise approved by the Nuclear Regulatory Commission.

PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.6.6. Plant operation within these operating limits is addressed in LCO 3.4.9, "RCS Pressure and Temperature (P/T) Limits."

B

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.

ADMINISTRATIVE CHANGES

A_{15} (cont'd) because the requirements are being moved to another TS, the change has no impact on any other definition, it does not change the intent of any Technical specification. Any technical change will be justified in the change package for Section 3.0. This change maintains the consistency between the PBAPS ITS and BWR/4 STS.

The table portion (Frequency notation versus specific time in hours, days, or months) of the Surveillance Frequency definition, as well as the last sentence of the first paragraph, is being deleted because the SR Frequencies in the PBAPS ITS do not use notation. The Frequencies for the SR lists the specific number of hours, days, or months (e.g.,instead of M--for Monthly, the PBAPS ITS will list 31 days).

The section in the frequency definition which states, "A surveillance test of the DGs that requires a plant outage may be deferred beyond the calculated due date until the next refueling outage, provided the equipment has been similarly tested and meets the surveillance requirement for the other unit" will be addressed in the discussion of changes for ITS Section 3.0, LCO and SR Applicability.

A_{16} Nine definitions are added to the PBAPS ITS. These definitions were added for consistency with the BWR/4 STS. These definitions are used throughout the PBAPS ITS and in the current PBAPS TS. The defined terms are used in the LCOs, SRs, and Bases of the TS and were defined for the convenience of the users of the TS. The inclusion of these definitions are deemed administrative and have no impact on their own. If the added definitions are used in new requirements (which is a technical change) the discussion of changes for the individual sections of the TS will provide the justification. | 5

A_{17} The following sections are being added to the TS. These additions aid the understanding and use of the new standard TS format and style of presentation. Some conventions in applying the TS to unique situations have previously been the subject of debate and interpretation by the licensee and the NRC Staff. Because the guidance in these proposed sections is presented in the BWR/4 STS, NUREG-1433 as approved by the NRC Staff, and the guidance is not a specific deviation from anything in the existing TS, these additions are considered to be administrative. The added sections are as follows:

Specification 3.1.3

~~LIMITING CONDITIONS FOR OPERATION~~ A1 ~~SURVEILLANCE REQUIREMENTS~~

~~3.3.A Reactivity Limitations (Cont'd)~~ A1

investigation demonstrates that the cause of the failure is not due to a failed control rod drive mechanism collet housing.

M2

L5 within 2 hours Required Action A.2 ~~4 hours~~ Required Action C.2

Required Actions A.2 & C.2

R1

b. The control rod directional control valves for inoperable control rods shall be disarmed electrically and the control rods shall be in such positions that Specification 3.3.A.1 is met. within 72 hours Required Action A.4 L4

Required Actions A.2 and C1 L4 B.1

c. ~~Control rods with scram times greater than those permitted by Specification 3.3.C.3 are inoperable, but if they can be inserted with control rod drive pressure they need not be disarmed electrically.~~ A2 M4

A1 ~~d. Deleted.~~

e. Control rods with inoperable accumulators or those whose position cannot be positively determined shall be considered inoperable. every 24 hours M5

SR 3.1.3.1

~~4.3.A Reactivity Limitations (Cont'd)~~ L2

~~or more inoperable control rods or when operating above the RWM low power setpoint if there is one fully or partially withdrawn rod which cannot be moved and for which control rod drive mechanism damage has not been ruled out. The surveillance need not be completed within 24 hours if the number of inoperable rods has been reduced to less than 3 and if it has been demonstrated that control rod drive mechanism collet housing failure is not the cause of an immovable control rod.~~ Required Action A.2 M2 L2 M2 L2 M2

b. The scram discharge volume drain and vent valves shall be verified open at least once per month. These valves may be closed intermittently for testing.

c. At least once every 3 months verify that the scram discharge volume drain and vent valves closed within 15 seconds after receipt of a closure signal, and reopen upon reset of the closure signal.

~~d. Deleted.~~

See Discussion of Changes for ITS 3.1.8, "Scram Discharge Volume Vent and Drain Valves."

See Discussion of Changes for ITS 3.1.5, "Control Rod Drive Scram Accumulators"

Specification 3.1.3

~~LIMITING CONDITIONS FOR OPERATION~~ A1 ~~SURVEILLANCE REQUIREMENTS~~

3.3.A Reactivity Limitations (Cont'd)

4.3.A Reactivity Limitations (Cont'd)

~~4.~~ Inoperable controls rods shall be positioned such that Specification 3.3.A.1 is met. In addition, during reactor power operation, no more than one control rod in any 5 x 5 array may be inoperable (at least 4 operable control rods must separate any 2 inoperable ones). If this Specification ~~cannot be met~~ the reactor shall not be started, or if at power, the reactor shall be brought to a ~~cold shutdown condition~~ within ~~24~~ 12 hours.

Required Actions A.4, B.1, ~~B.2~~, and C.1 M6

L9 L10 Action D

proposed Required Actions D.1 and D.2

LCO 3.0.4 A1

Action E M7

MODE 3 M7

B. Control Rods

1. ~~Each control rod shall be coupled to its drive or completely inserted and the control rod directional control valves disarmed electrically.~~ ~~This requirement does not apply in the refuel condition when the reactor is vented. Two control rod drives may be removed as long as Specification 3.3.A.1 is met.~~

A3 Required Actions C1 and C2 R1 A4

B. Control Rods

~~1.~~ 2. The coupling integrity shall be verified for each withdrawn control rod as follows: SR 3.1.3.5

a. ~~When a rod is withdrawn the first time after each refueling outage or after maintenance, observe discernible response of the nuclear instrumentation and rod position indication for the "full-in" and "full-out" position. However, for initial rods when response is not discernible, subsequent exercising of these rods after the reactor is above the Rod Worth Minimizer low power setpoint shall be performed to verify instrumentation response.~~ L6

~~b.~~ a. When the rod is fully withdrawn the first time after each refueling outage or after maintenance observe that the drive does not go to the overtravel position. SR 3.1.3.5 M8

Specification 3.1.3

~~LIMITING CONDITIONS FOR OPERATION~~ R

A1

~~SURVEILLANCE REQUIREMENTS~~ R

3.3.A ~~Reactivity Limitations~~ R ~~(Cont'd)~~ R

investigation demonstrates that the cause of the failure is not due to a failed control rod drive mechanism collet housing.

M2

Required Actions A.2 ~~and~~

L5

within 2 hours

4 hours

Required Action C.2

Required Actions A.3, ~~B.~~ & C.2

b. The control rod directional control valves for inoperable control rods shall be disarmed ~~electrically~~ and the control rods shall be in such positions that Specification 3.3.A.1 is met.

R1

Required Actions A.4, ~~B.~~ & C.1

B.1

within 72 hours

Required Action A.4

L4

c. ~~Control rods with scram times greater than those permitted by Specification 3.3.C.3 are inoperable, but if they can be inserted with control rod drive pressure they need not be disarmed electrically.~~

A2

M4

A1 ~~d. Deleted.~~ R

e. Control rods with inoperable accumulators or those whose position cannot be positively determined shall be considered inoperable.

SR 3.1.3.1

every 24 hours

M5

4.3.A ~~Reactivity Limitations~~ R ~~(Cont'd)~~ R

L3

inoperable control rods or or when operating above the RWM low power setpoint if there is one fully or partially withdrawn rod which cannot be moved and for which control rod drive mechanism damage has not been ruled out. ~~The surveillance need not be completed within 24 hours if the number of inoperable rods has been reduced to less than 3 and if it has been demonstrated that control rod drive mechanism collet housing failure is not the cause of an immovable control rod.~~

Required Action A.3

M2

M2 L2

L2

M2

B

b. The scram discharge volume drain and vent valves shall be verified open at least once per month. These valves may be closed intermittently for testing.

B

c. At least once every 3 months verify that the scram discharge volume drain and vent valves closed within 15 seconds after receipt of a closure signal, and reopen upon reset of the closure signal.

B

d. Deleted.

See Discussion of Changes for ITS 3.1.8, "Scram Discharge Volume Vent and Drain Valves"

See Discussion of Changes for ITS 3.1.5, "Control Rod Drive Scram Accumulators"

~~LIMITING CONDITIONS FOR OPERATION~~ A. ~~SURVEILLANCE REQUIREMENTS~~

~~3.3.A Reactivity Limitations (Cont'd)~~

~~4.3.A Reactivity Limitations (Cont'd)~~

B

f. Inoperable control rods shall be positioned such that specification 3.3.A.1 is met. In addition, during reactor power operation, no more than one control rod in any 5 x 5 array may be inoperable (at least 4 operable control rods must separate any 2 inoperable ones). If this Specification cannot be met the reactor shall not be started, or if at power, the reactor shall be brought to a cold shutdown condition within ~~24~~ 12 hours.

Required Actions A.4, ~~B.1~~ C.1, and ~~D.1~~ M6

L5

L10 ACTION D

L10 proposed Required Actions D.1 and D.2

LCO 3.0.4

ACTION E M7

M7 MODE 3

~~B.~~ Control Rods

~~1.~~ Each control rod shall be coupled to its drive or completely inserted and the control rod directional control valves disarmed electrically except as in 3.3.B.1.a. This requirement does not apply in the refuel condition when the reactor is vented. Two control rod drives may be removed as long as Specification 3.3.A.1 is met.

A4

Required Actions C.1 & C.2

R1

A5

A4

A5

~~a. For control rod 54-35, for the remainder of cycle 10 (to be completed before 10/30/95).~~

~~If coupling cannot be accomplished, the uncoupled control rod may be withdrawn when ≥10% of rated thermal power only if all the following conditions are satisfied:~~

~~1) no other uncoupled control rod is withdrawn;~~

~~2) the uncoupled control rod may not be withdrawn past notch position 46.~~

B. Control Rods

~~1.~~ The coupling integrity shall be verified for each withdrawn control rod as follows: SR 3.1.3.5

~~a. When a rod is withdrawn the first time after each refueling outage or after maintenance, observe discernible response of the nuclear instrumentation and rod position indication for the "full-in" and "full-out" position. However, for initial rods when response is not discernible, subsequent exercising of these rods after the reactor is above the Rod Worth Minimizer low power setpoint shall be performed to verify instrumentation response.~~ L6

~~b.~~ When the rod is fully withdrawn the first time after each refueling outage or after maintenance observe that the drive does not go to the overtravel position.

SR 3.1.3.5

M6

TECHNICAL CHANGES - MORE RESTRICTIVE

M_3 (cont'd) be fully inserted in 12 hours instead of 48 hours. Cooling the unit down (proceeding from Mode 3 to Mode 4) does not provide any additional margin and, in some case, could be counter productive since positive reactivity is inserted during a cooldown.

M_4 Currently, LCO 3.3.A.2.c provides an exception for the required actions for an inoperable control rod if the reason for inoperability is scram time > 7 seconds and the rod can be inserted with drive pressure.

The proposed requirement for declaring a rod inoperable because scram time exceeds 7 seconds (SR 3.1.3.4) requires that a rod be declared inoperable. Therefore, under the proposed change a rod with a scram time greater than 7 seconds must be fully inserted and disarmed in accordance with LCO 3.1.3 Condition C. This is more restrictive than the existing requirement which would allow the slow rod to remain withdrawn and armed.

M_5 Currently, LCO 3.3.A.2.e requires that a control rod whose position cannot be positively determined is inoperable; however, there is no requirement to periodically verify the position of each rod. This requirement has been modified to require the position of each control rod to be verified every 24 hours (proposed SR 3.1.3.1).

M_6 Existing Specification 3.3.A.2.f requires that inoperable (and stuck) control rods be positioned such that SDM requirements (3.3.A.1) are maintained.

The proposed required actions for LCO 3.1.3 require that: with one stuck rod (Required Action A.4) that SDM be verified within 72 hours (see L_4); with more than one stuck rod (Required Action B.1) that the reactor be in Hot Shutdown within 12 hours; and, with one or more inoperable rods (Required Action C.1) that each inoperable rod be fully inserted.

By allowing only one stuck rod, and by requiring that all inoperable rods be fully inserted, proposed Required Actions A.4, B.1, and C.1 provide greater assurance that SDM is maintained then the requirement for verifying SDM for multiple rods that remain withdrawn.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L_3 Currently, if one or more control rods are stuck, all operable control rods must be exercised "at least every 24 hours." In the proposed change, after discovery of a stuck rod, all withdrawn control rods are required to be exercised only once within 24 hours as per proposed Required Action A.3. This provides adequate assurance that the cause of the stuck rod is not of generic concern. Thereafter, continued testing of control rods per the normal frequency is sufficient to ensure continued operability of the remaining control rods. This change is in accordance with NUREG-1433. This change was also submitted for PBAPS Units 2 and 3 in Technical Specification Change Request 93-28, dated April 15, 1994.

L_4 Currently, LCO 3.3.A.2.b does not require that an inoperable rod be fully inserted prior to being disarmed because disarming the rod does not prevent the rod from scramming. The proposed requirement for an inoperable rod (3.1.3 Condition C) does require that an inoperable (but not stuck) rod be fully inserted before it is disarmed. Therefore, the proposed requirement eliminates the need for the SDM check that is necessary with the existing requirement.

Likewise, the existing requirement in LCO 3.3.A.2.b allows for multiple stuck rods that are not fully inserted. The proposed requirements (LCO 3.1.3 Conditions A and B) allow only one stuck rod before requiring that the reactor be shutdown (Mode 3) within 12 hours. Since there will never be more than only one stuck rod, the time allowed to perform a SDM check is extended to 72 hours. With only one stuck rod, the plant still falls within the established design limits that sufficient negative reactivity be available to shutdown the plant.

L_5 A new Completion Time to disarm the CRDs has been provided. The new time will allow a maximum of 2 hours for a stuck rod (proposed Required Action A.1) and 4 hours for an inoperable, non-stuck rod (proposed Required Action C.2) to complete this action. Currently, this action is required to be initiated immediately since no maximum time limit is provided.

The proposed Completion times for disarming inoperable control rods are reasonable, considering that the additional requirement to fully insert the rod has been added. The 2 hour or 4 hour time limit provides time to insert (for non-stuck only) and disarm control rods without challenging plant systems.

A~~LIMITING CONDITIONS FOR OPERATION~~ A1

LCO 3.2.1 ~~3.5.I~~ Average Planar LHGR A1 Applicability

A2 During power operation, ~~the APLHGR for each type of fuel~~ as a function of axial location and average planar exposure and reactor power/flow multipliers (provided in the CORE OPERATING LIMITS REPORT) shall be within limits based on applicable APLHGR limit values which have been determined by approved methodology for the respective fuel and lattice types. ~~When hand calculations are required, the APLHGR for each type of fuel as a function of average planar exposure shall not exceed the limit for the most limiting lattice (excluding natural uranium) specified in the CORE OPERATING LIMITS REPORT during two recirculation loop operations.~~ R1

Action A: If at any time during operation, it is determined by normal surveillance that the limiting value of APLHGR is being exceeded, ~~action shall be initiated within one (1) hour to restore APLHGR to within prescribed limits.~~ L1 If the APLHGR is not returned to within prescribed limits within ~~five (5)~~ 2 M2 hours,

Action B: reactor power shall be decreased at a rate which would bring the reactor to ~~the cold shutdown condition within 36 hours~~ < 25% RTP within 4 hours L2 unless APLHGR is returned to within limits during this period. ~~Surveillance and corresponding action shall continue until reactor operation is within the prescribed limits.~~ A3

~~SURVEILLANCE REQUIREMENTS~~

SR 3.2.1.1 ~~4.5.I~~ Average Planar LHGR

The APLHGR for each type of fuel as a function of average planar exposure and reactor power/flow multipliers (provided in the CORE OPERATING LIMITS REPORT) shall be checked ~~daily~~ during reactor operation at ≥25% rated thermal power.

Once within 12 hours after ≥ 25% RTP AND M1

B

3.5.J Local LHGR

During power operation, the linear heat generation rate (LHGR) of any rod in any fuel assembly at any axial location shall not exceed design LHGR.

LHGR ≤ LHGRd

LHGRd = Design LHGR
The values for Design LHGR for each fuel type are specified in the CORE OPERATING LIMITS REPORT.

4.5.J Local LHGR

The LHGR as a function of core height shall be checked daily during reactor operation at ≥25% rated thermal power.

See Discussion of Changes for ITS 3.2.3, "LHGR"

A1 ~~LIMITING CONDITIONS FOR OPERATION~~ R

A1 ~~SURVEILLANCE REQUIREMENTS~~ L

LCO 3.2.1 ~~3.5.I~~ Average Planar LHGR

A2 During power operation, ~~the APLHGR~~ Applicability for

LCO 3.2.1 each type of fuel as a function of axial location and average planar exposure and reactor power/flow multipliers (provided in the CORE OPERATING LIMITS REPORT) shall be within limits based on applicable APLHGR limit values which have been determined by approved methodology for the respective fuel and lattice types. ~~When hand calculations are required, the APLHGR for each type of fuel as a function of average planar exposure shall not exceed the limit for the most limiting lattice (excluding natural uranium) specified in the CORE OPERATING LIMITS REPORT during two recirculation loop operations.~~ R1

ACTION A If at any time during operation, it is determined by normal surveillance that the limiting value of APLHGR is being exceeded, ~~action shall be initiated within one (1) hour to restore APLHGR to within prescribed limits.~~ L1 If the APLHGR is not returned to within prescribed limits within ~~five (5)~~ 2 M2 hours,

ACTION B reactor power shall be decreased at a rate which would bring the reactor to ~~the cold shutdown condition within 36 hours~~ < 25% RTP within 4 hours ~~M3~~ L2 unless APLHGR is returned to within limits during this period. ~~Surveillance and corresponding action shall continue until reactor operation is within the prescribed limits.~~ A3

SR 3.2.1.1 ~~4.5.I~~ Average Planar LHGR

The APLHGR for each type of fuel as a function of average planar exposure and reactor power/flow multipliers (provided in the CORE OPERATING LIMITS REPORT) shall be checked ~~daily~~ during reactor operation at ≥25% rated thermal power.

Once within 12 hours after ≥ 25% RTP
AND
M1

3.5.J Local LHGR

During power operation, the linear heat generation rate (LHGR) of any rod in any fuel assembly at any axial location shall not exceed design LHGR.

LHGR ≤ LHGRd

LHGRd = Design LHGR
The values for Design LHGR for each fuel type are specified in the CORE OPERATING LIMITS REPORT.

4.5.J Local LHGR

The LHGR as a function of core height shall be checked daily during reactor operation at ≥25% rated thermal power.

See Discussion of Changes for ITS 3.2.3, "LHGR"

B

Amendment No. 33, 47, 62, 77, 79, 92, 130, 135, 184
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DISCUSSION OF CHANGES
ITS 3.2.1: AVERAGE PLANAR LINEAR HEAT GENERATION RATE

ADMINISTRATIVE CHANGES

A_1 Reformatting and renumbering requirements is in accordance with the BWR Standard Technical Specifications, NUREG-1433. As a result, the Technical Specifications should be more readily readable, and therefore understandable by plant operators as well as other users. During this reformatting and renumbering process, no technical changes (either actual or interpretational) to the Technical Specifications were made unless they were identified and justified.

A_2 The Applicability has been changed from "power operation" (i.e., ≥ 1% RTP) to "Thermal Power ≥ 25% RTP." This change is considered administrative in nature since the current surveillance only requires the limit to be checked when thermal power is ≥ 25% RTP. This change also implements human factors considerations to ensure that the Applicability and Surveillance Requirements work in conjunction with one another.

A_3 The requirement to continue the surveillance when the limits are not met has been deleted since the total allowed completion time for restoring the limit or placing the plant in a condition outside the Applicability is 6 hours. Since this 6 hour time frame is less than the Surveillance Frequency of 24 hours, the surveillance would not be required to be performed again while the plant was in the action. The requirement to continue to comply with actions until the limits are met has been moved and is now addressed by proposed LCO 3.0.2. As a result, these changes are administrative in nature.

TECHNICAL CHANGES - RELOCATIONS

R_1 The requirement regarding which limit to select from the Core Operating Limits Report (COLR) when limits are determined using hand calculations is relocated to plant procedures. Placing this requirement in procedures provides assurance that it will be maintained. The 10 CFR 50.59 control process for these procedures ensures that the requirement is appropriately maintained.

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 A new frequency has been added to require verifying the limit within 12 hours of reaching or exceeding 25% RTP. This is an additional restriction on plant operation.

M_2 The allowed completion time for restoring the limits has been reduced from 5 hours to 2 hours to be consistent with NUREG-1433. This is an additional restriction on plant operation.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

M_3 Not used.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 The requirement to initiate action within 1 hour to restore the limit is relaxed and relocated to the Bases in the form of a discussion that "prompt action" should be taken to restore the parameter to within limits. Immediate action may not always be the conservative method to assure safety. The 2 hour completion time for restoration of the limit allows appropriate actions to be evaluated by the operator and completed in a timely manner.

L_2 CTS 3.5.I (APLHGR), 3.5.J (LHGR), and 3.5.K (MCPR) require that if it is determined that the associated power distribution limit is not restored within the required time period, the reactor shall be in a Cold Shutdown within 36 hours. ITS 3.2.1 (APLHGR), 3.2.2 (MCPR), and 3.2.3 (LHGR) require that if the associated power distribution limit is not restored within the required Completion Time, reactor thermal power must be reduced to below 25% RTP within 4 hours. Since the ITS shutdown action does not require placing the unit in MODE 5 (Cold Shutdown), the change to the shutdown action has been categorized as a less restrictive change. The change is considered acceptable since the Applicabilities of CTS 3.5.I, 3.5.J, and 3.5.K are during reactor power operation at $\geq$ 25% rated thermal power. The Applicabilities of ITS 3.2.1, 3.2.2, and 3.2.3 are when THERMAL POWER is $\geq$ 25% RTP, which are equivalent to the CTS Applicabilities. In the event of a failure to comply with requirements of the LCO, the reactor must be placed in a non-applicable MODE or condition. The ITS change reflects placing the reactor in the first available non-applicable MODE or condition. This change also achieves consistency with CTS 3.0.A. CTS 3.0.A states "Limiting Conditions for Operation and action requirements are applicable during the operational conditions and other states specified for each specification." Since the applicability of the limiting condition for operation and actions for the CTS power distribution limits are during reactor power operation at $\geq$ 25% rated thermal power, reducing reactor thermal power to below 25% RTP results in exiting the power distribution limits' conditions of applicability. As a result, any further reduction in MODE or condition (to Cold Shutdown) is not required per CTS 3.0.A. In addition, not requiring the reactor to be placed in Cold Shutdown (mode switch in shutdown and average reactor coolant temperature $\leq$ 212°F) reduces the potential for an unnecessary shutdown transient and the resultant thermal effects on plant equipment.

Specification 3.2.2 ~~PBAPS~~ <See Discussion of changes For ITS 3.2.3 "LHGR"> TSCR 94-06

~~LIMITING CONDITIONS FOR OPERATION~~ A1

3.5.J Local LHGR (Cont'd)

If at any time during operation it is determined by normal surveillance that limiting value for LHGR is being exceeded, action shall be initiated within one (1) hour to restore LHGR to within prescribed limits. If the LHGR is not returned to within prescribed limits within five (5) hours, reactor power shall be decreased at a rate which would bring the reactor to the cold shutdown condition within 36 hours unless LHGR is returned to within limits during this period. Surveillance and corresponding action shall continue until reactor operation is within the prescribed limits.

~~3.5.K~~ Minimum Critical Power Ratio (MCPR)

LCO 3.2.2

Applicability A2

LCO 3.2.2 1. During power operation the MCPR for the applicable incremental cycle core average exposure and for each type of fuel shall be equal to or greater than the value given in Specification 3.5.K.2 or 3.5.K.3, or MCPR(F), or the MCPR operating limit as determined by application of MCPR(P), whichever is greater. MCPR(F) and MCPR(P) are provided in the CORE OPERATING LIMITS REPORT. If at any time during operation it is determined by normal surveillance that the limiting value for MCPR is being exceeded, action L1

Action A ~~shall be initiated within one (1) hour to restore MCPR to within prescribed limits.~~ M2

If the MCPR is not returned to within prescribed limits within ~~five (5)~~ 2 hours,

Action B reactor power shall be decreased at a rate which would bring the reactor to ~~the cold shutdown condition within 36 hours~~ unless MCPR is returned to within limits during this period. Surveillance and corresponding action shall continue until reactor operation is within the prescribed limits. A3

~~M3~~ L2 < 25% RTP within 4 hours

~~SURVEILLANCE REQUIREMENTS~~

~~4.5.K~~ Minimum Critical Power Ratio (MCPR) M1

SR 3.2.2.1 A1 Once within 12 hours after ≥ 25% RTP AND

1. MCPR shall be checked ~~daily~~ during reactor power operation at ≥25% rated thermal power.

SR 3.2.2.2

M4 2. Except as provided in Specification 3.5.K.3, the verification of the applicability of 3.5.K.2.a Operating Limit MCPR Values shall be performed every 120 operating days by scram time testing 19 or more control rods on a rotation basis and performing the following: a representative sample TSCR 94-06

~~a. The average scram time to the 20% insertion position shall be:~~

~~$\tau_{ave} \le \tau_B$~~

~~b. The average scram time to the 20% insertion position is determined as follows:~~

~~$$\tau_{ave} = \frac{\sum_{i=1}^{n} N_i \tau_i}{\sum_{i=1}^{n} N_i}$$~~

~~where: n = number of surveillance tests performed to date in the cycle.~~

R1

B

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PBAPS

See Discussion of changes for ITS 3.2.3, "LHGR"

LIMITING CONDITIONS FOR OPERATION (A1) SURVEILLANCE REQUIREMENTS

3.5.J Local LHGR (Cont'd)

If at any time during operation it is determined by normal surveillance that limiting value for LHGR is being exceeded, action shall be initiated within one (1) hour to restore LHGR to within prescribed limits. If the LHGR is not returned to within prescribed limits within five (5) hours, reactor power shall be decreased at a rate which would bring the reactor to the cold shutdown condition within 36 hours unless LHGR is returned to within limits during this period. Surveillance and corresponding action shall continue until reactor operation is within the prescribed limits.

(A1)
~~3.5.K~~ 9 Minimum Critical Power Ratio (MCPR)

LCO 3.2.2 (Applicability) (A2)

~~1.~~ During power operation the MCPR for the applicable incremental cycle core average exposure and for each type of fuel shall be equal to or greater than the value given in Specification 3.5.K.2 or 3.5.K.3, or MCPR(F), or the MCPR operating limit as determined by application of MCPR(P), whichever is greater. MCPR(F) and MCPR(P) are provided in the CORE OPERATING LIMITS REPORT. If at any time during operation it is determined by normal surveillance that the limiting value for MCPR is being exceeded, ~~action shall be initiated within one (1) hour to restore MCPR to within prescribed limits.~~ If the MCPR is not returned to within prescribed limits within ~~five (5)~~ 2 hours, reactor power shall be decreased at a rate which would bring the reactor to ~~the cold shutdown condition within 36 hours~~ unless MCPR is returned to within limits during this period. ~~Surveillance and corresponding action shall continue until reactor operation is within the prescribed limits.~~

LCO 3.2.2

Action A (L1)

(M2)

Action B

(A3)

(M3) < 25% RTP within 4 hours

(L2)

4.5.K Minimum Critical Power Ratio (MCPR)

(A1) (M1)

SR 3.2.2.1

Once within 12 hours after ≥ 25% RTP AND

1. MCPR shall be checked ~~daily~~ during reactor power operation at ≥25% rated thermal power.

SR 3.2.2.2

(M4)

~~2.~~ Except as provided in Specification 3.5.K.3, the verification of the applicability of 3.5.K.2.a Operating Limits MCPR Values shall be performed every 120 operating days ~~by scram time testing a representative sample of control rods and performing the following:~~

~~a. The average scram time to the 20% insertion position shall be:~~

$$\tau\ ave \leq \tau\ 8$$

~~b. The average scram time to the 20% insertion position is determined as follows:~~

$$\tau\ ave = \frac{\sum_{i=1}^{n} N_i \tau_i}{\sum_{i=1}^{n} N_i}$$

~~where: n = number of surveillance tests performed to date in the cycle.~~

(R1)

(B)

DISCUSSION OF CHANGES
ITS 3.2.2: MINIMUM CRITICAL POWER RATIO

ADMINISTRATIVE CHANGES

A_1 Reformatting and numbering requirements is in accordance with the BWR Standard Technical Specifications, NUREG-1433. As a result, the Technical Specifications should be more readily readable, and therefore understandable by plant operators as well as other users. During this reformatting and renumbering process, no technical changes (either actual or interpretational) to the Technical Specifications were made unless they were identified and justified.

A_2 The Applicability has been changed from "power operation" (i.e., ≥ 1% RTP) to "Thermal Power ≥ 25% RTP." This change is considered administrative in nature since the current surveillance only requires the limit to be checked when thermal power is ≥ 25% RTP. This change also implements human factors considerations to ensure that the Applicability and Surveillance Requirements work in conjunction with one another.

A_3 The requirement to continue the surveillance when the limits are not met has been deleted since the total allowed completion time for restoring the limit or placing the plant in a condition outside the Applicability is 6 hours. Since this 6 hour time frame is less than the Surveillance Frequency of 24 hours, the surveillance would not be required to be performed again while the plant was in the action. The requirement to continue to comply with actions until the limits are met has been moved and is now addressed by proposed LCO 3.0.2. As a result, these changes are administrative in nature.

TECHNICAL CHANGES - RELOCATIONS

R_1 The method used for determining τ and the acceptance criteria are relocated to plant procedures. Placing these requirements in procedures provides assurance that they will be maintained. The 10 CFR 50.59 control process for these procedures ensures that the requirement is appropriately maintained.

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 A new frequency has been added to require verifying the limit within 12 hours of reaching or exceeding 25% RTP. This is an additional restriction on plant operation.

M_2 The allowed completion time for restoring the limits has been reduced from 5 hours to 2 hours to be consistent with NUREG-1433. This is an additional restriction on plant operation.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

M_3 Not used.

M_4 Currently, Specification 4.5.K.2 requires verification of the applicability of the Operating Limit MCPR values every 120 operating days by performing scram time testing. However, no specific time limit exists for determining the MCPR limits after completion of the tests. Therefore, a Completion Time of 72 hours has been provided for determining MCPR limits after completion of these scram time tests (per SR 3.1.4.2, which requires scram time testing every 120 days, consistent with the Frequency of Specification 4.5.K.2). This is an additional restriction on plant operations to ensure that MCPR limits are updated in a timely manner. In addition, the test is also required after initial scram time testing following a shutdown > 120 days (per proposed SR 3.1.4.1 scram time frequency requirement.)

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 The requirement to initiate action within 1 hour to restore the limit is relaxed and relocated to the Bases in the form of a discussion that "prompt action" should be taken to restore the parameter to within limits. Immediate action may not always be the conservative method to assure safety. The 2 hour completion time for restoration of the limit allows appropriate actions to be evaluated by the operator and completed in a timely manner.

L_2 CTS 3.5.I (APLHGR), 3.5.J (LHGR), and 3.5.K (MCPR) require that if it is determined that the associated power distribution limit is not restored within the required time period, the reactor shall be in a Cold Shutdown within 36 hours. ITS 3.2.1 (APLHGR), 3.2.2 (MCPR), and 3.2.3 (LHGR) require that if the associated power distribution limit is not restored within the required Completion Time, reactor thermal power must be reduced to below 25% RTP within 4 hours. Since the ITS shutdown action does not require placing the unit in MODE 5 (Cold Shutdown), the change to the shutdown action has been categorized as a less restrictive change. The change is considered acceptable since the Applicabilities of CTS 3.5.I, 3.5.J, and 3.5.K are during reactor power operation at ≥ 25% rated thermal power. The Applicabilities of ITS 3.2.1, 3.2.2, and 3.2.3 are when THERMAL POWER is ≥ 25% RTP, which are equivalent to the CTS Applicabilities. In the event of a failure to comply with requirements of the LCO, the reactor must be placed in a non-applicable MODE or condition. The ITS change reflects placing the reactor in the first available

TECHNICAL CHANGES - MORE RESTRICTIVE

L_2 (cont'd) non-applicable MODE or condition. This change also achieves consistency with CTS 3.0.A. CTS 3.0.A states "Limiting Conditions for Operation and action requirements are applicable during the operational conditions and other states specified for each specification." Since the applicability of the limiting condition for operation and actions for the CTS power distribution limits are during reactor power operation at $\geq$ 25% rated thermal power, reducing reactor thermal power to below 25% RTP results in exiting the power distribution limits' conditions of applicability. As a result, any further reduction in MODE or condition (to Cold Shutdown) is not required per CTS 3.0.A. In addition, not requiring the reactor to be placed in Cold Shutdown (mode switch in shutdown and average reactor coolant temperature $\leq$ 212°F) reduces the potential for an unnecessary shutdown transient and the resultant thermal effects on plant equipment.

B

~~LIMITING CONDITIONS FOR OPERATION~~ A1

A1 ~~3.5.J Local LHGR (Cont'd)~~

LCO 3.2.3

Action A

If at any time during operation it is determined by normal surveillance that limiting value for LHGR is being exceeded, ~~action shall be initiated within one (1) hour to restore LHGR to within prescribed~~ L1 limits. If the LHGR is not returned to within prescribed limits within ~~five (5)~~ 2 M2 hours, reactor power shall be decreased at a rate which would bring the reactor to ~~the cold shutdown condition within 36 hours~~ < 25% RTP within 4 hours unless LHGR is returned to within limits during this period.

Action B

~~Surveillance and corresponding action shall continue until reactor operation is within the prescribed limits.~~ ~~M3~~ L2 A3

3.5.K Minimum Critical Power Ratio (MCPR)

1. During power operation the MCPR for the applicable incremental cycle core average exposure and for each type of fuel shall be equal to or greater than the value given in Specification 3.5.K.2 or 3.5.K.3, or MCPR(F), or the MCPR operating limit as determined by application of MCPR(P), whichever is greater. MCPR(F) and MCPR(P) are provided in the CORE OPERATING LIMITS REPORT. If at any time during operation it is determined by normal surveillance that the limiting value for MCPR is being exceeded, action shall be initiated within one (1) hour to restore MCPR to within prescribed limits. If the MCPR is not returned to within prescribed limits within five (5) hours, reactor power shall be decreased at a rate which would bring the reactor to the cold shutdown condition within 36 hours unless MCPR is returned to within limits during this period. Surveillance and corresponding action shall continue until reactor operation is within the prescribed limits.

~~SURVEILLANCE REQUIREMENTS~~

4.5.K Minimum Critical Power Ratio (MCPR)

1. MCPR shall be checked daily during reactor power operation at ≥25% rated thermal power.

2. Except as provided in Specification 3.5.K.3, the verification of the applicability of 3.5.K.2.a Operating Limit MCPR Values shall be performed every 120 operating days by scram time testing ~~19 or more~~ a representative sample control rods on a rotation basis and performing the following: TSCR 94-06

B

a. The average scram time to the 20% insertion position shall be:

$$\tau_{ave} \le \tau_B$$

b. The average scram time to the 20% insertion position is determined as follows:

$$\tau_{ave} = \frac{\sum_{i=1}^{n} N_i \tau_i}{\sum_{i=1}^{n} N_i}$$

where: n = number of surveillance tests performed to date in the cycle.

See Discussion of changes for ITS 3.2.2, "MCPR"

A1

~~LIMITING CONDITIONS FOR OPERATION~~ — ~~SURVEILLANCE REQUIREMENTS~~

LCO 3.2.3

~~3.5.J~~ Local LHGR (Cont'd)

Action A

If at any time during operation it is determined by normal surveillance that limiting value for LHGR is being exceeded, ~~action shall be initiated within one (1) hour to restore LHGR to within prescribed limits.~~ L1 If the LHGR is not returned to within prescribed limits within ~~five (5)~~ 2 M2 hours, reactor power shall be decreased at a rate which would bring the reactor to ~~the cold shutdown condition within 36 hours~~ ≤ 25% RTP within 4 hours L2 unless LHGR is returned to within limits during this period.

Action B

A3 ~~Surveillance and corresponding action shall continue until reactor operation is within the prescribed limits.~~

3.5.K Minimum Critical Power Ratio (MCPR)

1. During power operation the MCPR for the applicable incremental cycle core average exposure and for each type of fuel shall be equal to or greater than the value given in Specification 3.5.K.2 or 3.5.K.3, or MCPR(F), or the MCPR operating limit as determined by application of MCPR(P), whichever is greater. MCPR(F) and MCPR(P) are provided in the CORE OPERATING LIMITS REPORT. If at any time during operation it is determined by normal surveillance that the limiting value for MCPR is being exceeded, action shall be initiated within one (1) hour to restore MCPR to within prescribed limits. If the MCPR is not returned to within prescribed limits within five (5) hours, reactor power shall be decreased at a rate which would bring the reactor to the cold shutdown condition within 36 hours unless MCPR is returned to within limits during this period. Surveillance and corresponding action shall continue until reactor operation is within the prescribed limits.

4.5.K Minimum Critical Power Ratio (MCPR)

1. MCPR shall be checked daily during reactor power operation at ≥25% rated thermal power.

2. Except as provided in Specification 3.5.K.3, the verification of the applicability of 3.5.K.2.a Operating Limits MCPR Values shall be performed every 120 operating days by scram time testing a representative sample of control rods and performing the following:

a. The average scram time to the 20% insertion position shall be:

$$\tau \text{ ave} \leq \tau \text{ B}$$

b. The average scram time to the 20% insertion position is determined as follows:

$$\tau \text{ ave} = \frac{\sum_{i=1}^{n} N_i \tau_i}{\sum_{i=1}^{n} N_i}$$

where: n = number of surveillance tests performed to date in the cycle.

See Discussion of Changes for ITS 3.2.2, "MCPR"

DISCUSSION OF CHANGES
ITS 3.2.3: LINEAR HEAT GENERATION RATE

ADMINISTRATIVE CHANGES

A_1 Reformatting and renumbering requirements is in accordance with the BWR Standard Technical Specifications, NUREG-1433. As a result, the Technical Specifications should be more readily readable, and therefore understandable by plant operators as well as other users. During this reformatting and renumbering process, no technical changes (either actual or interpretational) to the Technical Specifications were made unless they were identified and justified.

A_2 The Applicability has been changed from "power operation" (i.e., ≥ 1% RTP) to "Thermal Power ≥ 25% RTP." This change is considered administrative in nature since the current surveillance only requires the limit to be checked when thermal power is ≥ 25% RTP. This change also implements human factors considerations to ensure that the Applicability and Surveillance Requirements work in conjunction with one another.

A_3 The requirement to continue the surveillance when the limits are not met has been deleted since the total allowed completion time for restoring the limit or placing the plant in a condition outside the Applicability is 6 hours. Since this 6 hour time frame is less than the Surveillance Frequency of 24 hours, the surveillance would not be required to be performed again while the plant was in the action. The requirement to continue to comply with actions until the limits are met has been moved and is now addressed by proposed LCO 3.0.2. As a result, these changes are administrative in nature.

TECHNICAL CHANGES - RELOCATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 A new frequency has been added to require verifying the limit within 12 hours of reaching or exceeding 25% RTP. This is an additional restriction on plant operation.

M_2 The allowed completion time for restoring the limits has been reduced from 5 hours to 2 hours to be consistent with NUREG-1433. This is an additional restriction on plant operation.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

M_3 Not used.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 The requirement to initiate action within 1 hour to restore the limit is relaxed and relocated to the Bases in the form of a discussion that "prompt action" should be taken to restore the parameter to within limits. Immediate action may not always be the conservative method to assure safety. The 2 hour completion time for restoration of the limit allows appropriate actions to be evaluated by the operator and completed in a timely manner.

L_2 CTS 3.5.I (APLHGR), 3.5.J (LHGR), and 3.5.K (MCPR) require that if it is determined that the associated power distribution limit is not restored within the required time period, the reactor shall be in a Cold Shutdown within 36 hours. ITS 3.2.1 (APLHGR), 3.2.2 (MCPR), and 3.2.3 (LHGR) require that if the associated power distribution limit is not restored within the required Completion Time, reactor thermal power must be reduced to below 25% RTP within 4 hours. Since the ITS shutdown action does not require placing the unit in MODE 5 (Cold Shutdown), the change to the shutdown action has been categorized as a less restrictive change. The change is considered acceptable since the Applicabilities of CTS 3.5.I, 3.5.J, and 3.5.K are during reactor power operation at ≥ 25% rated thermal power. The Applicabilities of ITS 3.2.1, 3.2.2, and 3.2.3 are when THERMAL POWER is ≥ 25% RTP, which are equivalent to the CTS Applicabilities. In the event of a failure to comply with requirements of the LCO, the reactor must be placed in a non-applicable MODE or condition. The ITS change reflects placing the reactor in the first available non-applicable MODE or condition. This change also achieves consistency with CTS 3.0.A. CTS 3.0.A states "Limiting Conditions for Operation and action requirements are applicable during the operational conditions and other states specified for each specification." Since the applicability of the limiting condition for operation and actions for the CTS power distribution limits are during reactor power operation at ≥ 25% rated thermal power, reducing reactor thermal power to below 25% RTP results in exiting the power distribution limits' conditions of applicability. As a result, any further reduction in MODE or condition (to Cold Shutdown) is not required per CTS 3.0.A. In addition, not requiring the reactor to be placed in Cold Shutdown (mode switch in shutdown and average reactor coolant temperature ≤ 212°F) reduces the potential for an unnecessary shutdown transient and the resultant thermal effects on plant equipment.

DISCUSSION OF CHANGES
ITS 3.2: POWER DISTRIBUTION LIMITS BASES

The Bases of the current Technical Specifications for this section (pages 140 through 140c, 141 and 141a) have been completely replaced by revised Bases that reflect the format and applicable content of proposed PBAPS Units 2 and 3 Technical Specifications Section 3.2, consistent with NUREG-1433. The revised Bases are as shown in the proposed PBAPS Units 2 and 3 Bases. In addition, pages 140d, 140e, 141b, 142, and 142b through 142g, which are blank pages, have been deleted.

~~LIMITING CONDITIONS FOR OPERATION~~ A1 ~~SURVEILLANCE REQUIREMENTS~~

~~3.1 Reactor Protection System (RPS)~~ A1 ~~4.1 Reactor Protection System~~ A5 SR Note 1

LCO 3.3.1.1 A1

~~A.~~ The RPS instrumentation for each trip function in Table ~~3.1.1~~ 3.3.1.1-1 shall be Operable; and, there shall be two Operable or tripped trip systems for each Trip Function. Condition A A1

A. Each RPS instrument channel shall be demonstrated Operable by performance of a channel functional test and channel calibration at the Frequencies shown in Tables ~~4.1.1~~ and ~~4.1.2~~, respectively.

~~The designed system response times from the opening of the sensor contact up to and including the opening of the trip actuator contacts shall not exceed 50 milliseconds.~~ R2

Response time measurements (from the opening of the sensor contact up to and including the opening of the trip actuator contacts) ~~are not part of the normal instrument test.~~ A1 The RPS response time of each reactor trip function in Table 4.1.2 A11 shall be demonstrated to be within its limits once per operating cycle. SR 3.3.1.1.18 A1

B

Applicability:

According to Table ~~3.1.1~~. 3.3.1.1-1 A1

Conditions and Required Actions: ~~(1)(2)~~ A1

1. With one or more channel(s) required by Table ~~3.1.1~~ 3.3.1.1-1 A1 inoperable in one or more trip functions, place the inoperable channel or associated trip system in trip within 12 hours. Action A

See Discussion of Changes for ITS 1.0, "Use and Application"

2. With one or more trip functions with one or more channels required by Table ~~3.1.1~~ 3.3.1.1-1 A1 inoperable in both trip systems, place channel in one trip system in trip or place one trip system in trip within 6 hours. Action B

3. With one or more automatic trip functions or two or more manual trip functions (Mode Switch in Shutdown, Manual Scram and RPS Channel Test Switches) with RPS trip capability not maintained, restore RPS trip capability within one hour. Action C

4. If the required actions and associated completion time of Action 1 or 2 or 3 are not met, take the action required by Table ~~3.1.1~~ 3.3.1.1-1 A1 for the Trip Function. Action D

A1 Surveillance Requirements Note 2

A1 ~~(1)~~ When a channel is placed in an inoperable status solely for performance of required Surveillances, initiation of these Actions may be delayed for up to 6 hours provided the associated trip function maintains RPS trip capability.

(2) An inoperable channel or trip system need not be placed in the tripped condition where this would cause the trip function to occur. In these cases, if the inoperable channel is not restored to Operable status within the required time, the Action required by Table 3.1.1 for that trip function shall be taken immediately. R13

~~LIMITING CONDITIONS FOR OPERATION~~ A1 ~~SURVEILLANCE REQUIREMENTS~~

~~3.1 Reactor Protection System (RPS)~~ A1 ~~4.1 Reactor Protection System~~ A5 SR Note 1

LCO 3.3.1.1 A1

~~A.~~ The RPS instrumentation for each trip function in Table ~~3.1.1~~ 3.3.1.1-1 A1 shall be Operable; and, there shall be two Operable or tripped trip systems for each Trip Function. Condition A A1

A. Each RPS instrument channel shall be demonstrated Operable by performance of a channel functional test and channel calibration at the Frequencies shown in Tables ~~4.1.1~~ and ~~4.1.2~~ respectively.

The designed system response times from the opening of the sensor contact up to and including the opening of the trip actuator contacts shall not exceed 50 milliseconds. R3

Response time measurements (from the opening of the sensor contact up to and including the opening of the trip actuator contacts) ~~are not part of the normal instrument test.~~ A1 The RPS response time of each reactor trip function shall be demonstrated to be within ~~its limits~~ once per operating cycle. SR 3.3.1.1.18 A1

in Table 4.1.2 A11

Applicability:

According to Table ~~3.1.1~~ 3.3.1.1-1 A1

Conditions and Required Actions: ~~(1)(2)~~ A1

1. With one or more channel(s) required by Table ~~3.1.1~~ 3.3.1.1-1 A1 inoperable in one or more trip functions, place the inoperable channel or associated trip system in trip within 12 hours. Action A

2. With one or more trip functions ~~with one~~ or more channels required by Table ~~3.1.1~~ 3.3.1.1-1 A1 inoperable in both trip systems, place channel in one trip system in trip or place one trip system in trip within 6 hours. Action B

3. With one or more automatic trip functions or two or more manual trip functions (Mode Switch in Shutdown, Manual Scram and RPS Channel Test Switches) with RPS trip capability not maintained, restore RPS trip capability within one hour. Action C

4. If the required actions and associated completion time of Action 1 or 2 or 3 are not met, take the action required by Table ~~3.1.1~~ 3.3.1.1-1 A1 for the Trip Function. Action D

See Discussion of Changes for ITS 1.0, "Use and Application"

B

A1 Surveillance Requirements Note 2

A1 ~~(1)~~ When a channel is placed in an inoperable status solely for performance of required Surveillances, initiation of these Actions may be delayed for up to 6 hours provided the associated trip function maintains RPS trip capability.

(2) An inoperable channel or trip system need not be placed in the tripped condition where this would cause the trip function to occur. In these cases, if the inoperable channel is not restored to Operable status within the required time, the Action required by Table 3.1.1 for that trip function shall be taken immediately.

ADMINISTRATIVE CHANGES

A_{10} (cont'd) The intent of the action is more appropriately presented in Required Action H.1. With the proposed action, a more conservative requirement to immediately insert the control rod(s), if capable, and to maintain them inserted is imposed. With this conservatism however, comes the understanding that if best efforts to insert the control rod(s) took longer than 12 hours, no LER would be required.

This interpretation of the intent is supported by NUREG-1433. As an enhanced presentation of the existing intent, the proposed changes are considered to be administrative.

A_{11} In Technical Specification Change Request (TSCR) 90-03 (transmitted by letter from G.A.Hunger (PECO Energy) to USNRC Document Control Desk dated September 26, 1994), the Surveillance Requirement for RPS response time testing was moved from CTS Table 4.1.2, Note 4, to CTS 4.1.A so that the RPS response time Surveillance Requirement would be located symmetrically to the corresponding CTS LCO requirement for RPS response times. TSCR 90-03 described this change as an administrative change because there were supposed to be no technical changes (either actual or interpretational) to the Technical Specifications. TSCR 90-03 was subsequently approved in Amendment Numbers 203 and 206 for PBAPS Units 2 and 3, respectively.

Prior to the issuance of the amendments associated with TSCR 90-03, Note 4 of CTS Table 4.1.2 stated the response time is not a part of the routine instrument channel test but will be checked once per operating cycle. Note 4 of CTS Table 4.1.2 applied to only those RPS trip functions listed in CTS Table 4.1.2. The list of RPS trip functions in CTS Table 4.1.2 includes all RPS trip functions of CTS 3.1 and 4.1, Reactor Protection System, except the following:

Mode Switch in Shutdown,

Manual Scram,

RPS Channel Test Switch,

IRM Inoperative,

APRM Inoperative, and

APRM Downscale.

ADMINISTRATIVE CHANGES

A_{11} (cont'd) In moving the response time requirement of Note 4 of CTS Table 4.1.2 to CTS 4.1.A, an error was made. CTS 4.1.A was erroneously revised to state:

> "The RPS response time test for each reactor trip function shall be demonstrated to be within limits once per operating cycle."

Since this change was described in TSCR 90-03 as an administrative change, no new response time requirements should have been imposed. However, as presently written CTS 4.1.A requires RPS response time testing to be performed on each RPS trip function which not only includes the RPS trip functions listed in CTS Table 4.1.2, but also includes the Mode Switch in Shutdown, Manual Scram, RPS Channel Test Switch, IRM Inoperative, APRM Inoperative, and APRM Downscale Functions. Prior to the issuance of the amendments associated with TSCR 90-03, RPS response time testing was not required for these additional RPS trip functions by the PBAPS Technical Specifications. To correct this error, CTS 4.1.A should state:

> "The RPS response time test for each reactor trip function in Table 4.1.2 shall be demonstrated to be within limits once per operating cycle."

Therefore, the RPS response time requirements will be added to the PBAPS ITS consistent with the correct version of CTS 4.1.A, above. Since the proposed change is correcting an error made during the processing of a Technical Specification change, there is no impact on safety. In addition, the affected RPS trip functions for which response time testing requirements were erroneously imposed are not assumed in the mitigation of design basis accidents or transient analyses.

B

RPS response time Surveillance Requirements for each of the RPS trip functions in CTS Table 4.1.2 have been explicitly applied to the corresponding Functions in PBAPS ITS Table 3.3.1.1-1, except for the LPRM Signal Function and the Turbine First Stage Pressure Permissive Function. The response time test requirements are not explicitly listed for the LPRM Signal Function in PBAPS ITS Table 3.3.1.1-1 since the LPRMs are considered to be part of the APRM channel as described in the Bases for ITS 3.3.1.1. Therefore, the CTS response time test requirements for LPRMs are adequately addressed by the proposed response time testing requirements for the associated APRM Functions in PBAPS ITS Table 3.3.1.1-1. The response time test requirements are also not explicitly listed for the Turbine First

ADMINISTRATIVE CHANGES

A_{11} (cont'd) Stage Pressure Permissive Function in PBAPS ITS Table 3.3.1.1-1 since the Turbine First Stage Pressure Permissive Function is an interlock associated with the Turbine Stop Valve - Closure Function channels and Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Function channels as described in the Bases for ITS 3.3.1.1. Therefore, the CTS response time test requirements for the Turbine First Stage Pressure Permissive are adequately addressed by the proposed response time testing requirements for the associated Turbine Stop Valve - Closure Function and Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Function in PBAPS ITS Table 3.3.1.1-1. As a result, all RPS response time requirements of CTS Table 4.1.2 are considered to be addressed, either explicitly or implicitly, by the proposed revision to PBAPS ITS 3.3.1.1 and PBAPS ITS Table 3.3.1.1-1.

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 The proposed change will add restrictions to the provision which allows the Scram Discharge Volume High Function to be bypassed when the mode switch is in refuel or shutdown. The proposed change requires this Function to be Operable whenever any control rod is withdrawn from a core cell containing one or more fuel assemblies. This will ensure that if an RPS initiated scram occurs the control rod insertion will not be hindered by the scram discharge volume being too high. This change is consistent with NUREG-1433.

M_2 The proposed change will require the plant to be in MODE 3 if Actions A, B, or C cannot be completed within the required Completion Time (which is outside the Modes of Applicability). The current requirement allows the plant to be taken to MODE 2 with or without the control rods inserted. Since the APRM Inoperative is required to be Operable whenever the other APRM Functions are Operable and the APRM Startup High Flux Scram Function is required in MODE 2, bringing the plant to MODE 2 will not place the Function outside its Mode of Applicability. Therefore, it is more appropriate to bring the plant to MODE 3 which is outside the Modes of Applicability. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

M_3 This proposed change adds the following Surveillance Requirements for the RPS Functions in the Technical Specification.

- Requirements to perform Channel Checks every 12 hours (SR 3.3.1.1.1) were added for the functions listed below:

  IRM High Flux (Mode 2 and Mode 5)
  APRM Startup High Flux Scram (Mode 2)
  APRM Flow Biased High Scram
  APRM Scram Clamp
  Main Steam Line High Radiation

- A requirement was added to verify SRM and IRM channels overlap prior to withdrawing SRMs from the fully inserted position (SR 3.3.1.1.5).

- A requirement was added to perform a Channel Functional Test every 92 days for the APRM Flow Biased High Scram Function.

- A Requirement was added to perform a Channel Calibration of the function listed below every 184 days (SR 3.3.1.1.11):

  IRM High Flux (Mode 2 and Mode 5)

- A requirement was added to perform a Channel Calibration of the functions listed every 18 months (SR 3.3.1.1.12):

  APRM Startup High Flux Scram (Mode 2)
  APRM Scram Clamp

- Requirements were added to perform Logic System Functional Tests every 24 months (SR 3.3.1.1.17) for the following functions:

  IRM High Flux (Mode 2 and Mode 5)
  IRM Inop (Mode 2 and Mode 5)
  APRM Startup High Flux Scram (Mode 2)
  APRM Flow Biased High Scram
  APRM Scram Clamp
  APRM Downscale
  APRM Inop (Mode 1 and Mode 2)
  Reactor Vessel Pressure High
  Reactor Vessel Water Level Low
  Main Steam Isolation Valve Closure
  Drywell Pressure High

TECHNICAL CHANGES - MORE RESTRICTIVE

M_3 (cont'd)

SDV Water Level High (Mode 1, Mode 2, and Mode 5)
Turbine Stop Valve Closure
Turbine Control Valve Fast Closure, Trip Oil Pressure Low
Reactor Mode Switch - Shutdown Position (Mode 1, Mode 2, and Mode 5)
Turbine Condenser Low Vacuum
Main Steam Line High Radiation
Manual Scram (Mode 1, Mode 2, and Mode 5)
RPS Channel Test Switch (Mode 1, Mode 2, and Mode 5)

The addition of new requirements (Surveillances) to the current Technical Specifications constitutes a more restrictive change. This change is consistent with NUREG-1433.

M_4 The proposed change will increase the Frequency of the Channel Checks for current Technical Specification RPS Functions of High Steam Dome Pressure, High Drywell Pressure, Reactor Low Water Level, and Turbine Condenser Low Vacuum from once per day to once per 12 hours. The Channel Check ensures that a gross failure of instrumentation has not occurred. By detecting these gross failures, the Channel Check is the key to verifying the instrument continues to operate properly between each Channel Calibration. This change adds additional requirements and it constitutes a more restrictive change. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS

R_1 This change proposes to relocate the terms and definitions (S, W, and ΔW) for the setting of the APRM Flowed Biased High Scram equation. This function monitors neutron flux to approximate the thermal power being transferred to the reactor coolant. These definitions will be relocated to a licensee controlled document. Any changes to these definitions will undergo a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_2 This change proposes to relocate the APRM Flow Biased Scram Relationship to Normal Operating Conditions Figure to a licensee controlled document. Any changes to this curve will undergo a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS (continued)

R_3 The specific design value (50 milliseconds) for the RPS response time acceptance criterion is proposed to be relocated to the PBAPS UFSAR consistent with NRC Generic Letter 93-08. This is considered to be acceptable since the requirements of SR 3.3.1.1.18 are adequate to ensure the affected RPS functions are tested to ensure response times are maintained within required limits. SR 3.3.1.1.18 of Specification 3.3.1.1 requires RPS response times to be verified within limits once per 24 months. If the requirements of SR 3.3.1.1.18 are not satisfied, SR 3.0.1 requires the affected channels of the RPS to be declared inoperable and the ACTIONS of Specification 3.3.1.1 entered. In addition, placing the RPS response time acceptance criterion in the UFSAR provides assurance that it will be maintained. The 10 CFR 50.59 control process for the UFSAR ensures that the requirement is appropriately maintained. As a result, the requirements proposed to be relocated are not required to be included in the Technical Specifications to ensure required RPS response time testing is performed and RPS response times are maintained within required limits. B

R_4 This change proposes to relocate the details of the performance of the Channel Functional Test of the Mode Switch in Shutdown Function which states to place the Mode Switch in Shutdown. The specifics of the performance of the test will be relocated to the plant surveillance procedures. Details of the performance of procedures have been relocated to licensee controlled documents. Any changes to this requirement will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_5 This change relocates the requirement that an APRM will be considered Operable if there are at least 2 LPRM inputs per level and at least 14 LPRM inputs of the normal complement. These requirements will be relocated to the Bases. Any changes to these requirements (consistent with changes to the Bases) will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_6 This change proposes to relocate the number of instrument channels provided by design column for each Function. This information will be relocated to the Bases of the proposed Technical Specifications. Any changes to this requirement will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_7 This change proposes to relocate the statement regarding the functions design which permits closure of any two lines without a scram being initiated. This information will be relocated to the UFSAR. Any changes to this requirement will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS (continued)

R_8 This change proposes to relocate Note 5, "IRM's are bypassed when APRM's are onscale and the reactor mode switch is in the run position," which is associated with the IRM High Flux and IRM Inoperative Functions and Note 10, "the APRM downscale trip is automatically bypassed when the IRM instrumentation is operable and not high," which is associated with the APRM Downscale Function. These notes will be relocated to plant procedures. Any changes to these requirements will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_9 This change proposes to relocate discussions/specifics (e.g., what's required to be tested for each Function, equipment required for the test, how to perform the test, etc.) concerning surveillance tests to the specific plant surveillance test procedure. This change is consistent with NUREG-1433. Any changes to these requirements will require a 10 CFR 50.59 review.

R_{10} This change proposes to relocate the requirements of Note 3, related to the Minimum Frequency column of current Table 4.1.1, to a licensee controlled document. This requirement specifies that "functional tests are not required on the part of the system that is not required to be operable or are tripped. If tests are missed on parts not required to be operable or are tripped, then they shall be performed prior to returning the system to an operable status." This requirement will be relocated to a licensee controlled document such as the procedure governing performance of surveillance tests. Any changes to this requirement will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433. In addition, proposed SR 3.0.1 and the associated Bases will also ensure this current requirement is maintained.

R_{11} This change proposes to relocate the requirements for a Channel Functional Test after maintenance is performed to a licensee controlled document (e.g., post maintenance procedures). Post maintenance requirements are being relocated out of the Technical Specifications. Any changes to the current post maintenance testing requirements for the RPS Test Switch will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_{12} This change proposes to relocate the current "Trip Level Setting" column in current Technical Specifications Table 3.3.1 and replace it with an "Allowable Value" column in the proposed Technical Specifications Table 3.3.1.1-1. Trip setpoints are an operational detail that is not directly related to the Operability of the instrumentation and will be relocated to a licensee controlled

TECHNICAL CHANGES - RELOCATIONS

R_{12} (cont'd) document. The Allowable Value is the required limitation for the parameter and this value will be inserted in the table. Any change to the trip setpoints will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_{13} System operational details (when not to place in trip) have been relocated to the Bases and procedures. These details are unnecessary in the LCO and can be adequately controlled in the Bases and procedures. Changes to the Bases will be controlled by the provisions of the Bases Control Process in Chapter 5 of the Technical Specifications. Changes to procedures will be controlled by the provisions of 10 CFR 50.59.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 The proposed change adds a note to the 184 day and 18 month Channel Calibration Surveillance Requirements excluding the neutron detectors from these Surveillances. The Channel Calibration is a complete check of the instrument loop and the sensor. The test verifies that the channel responds to the measured parameter within the necessary range and accuracy. The neutron detectors are excluded from the Channel Calibrations because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performance of the 7 day calorimetric calibration (SR 3.3.1.1.2) and the 1000 MWD/T LPRM calibration against the TIPs (SR 3.3.1.1.8). This change is consistent with NUREG-1433.

L_2 This change proposes to relax the following requirement for the specified Functions.

- The Mode Switch in Shutdown, Manual Scram, High Flux IRM, IRM Inoperable, and High Scram Discharge Volume Water Level (this Function is currently modified by a note which states it is permissible to bypass this Function when the mode switch is in refuel or shutdown; this will be addressed in M_1 Discussion of Changes for ITS 3.3.1.1) Functions will be Operable with the mode switch in refuel, the reactor subcritical, and the water temperature less than 212°F.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_2 (cont'd) The proposed change will require the above Functions to be Operable only when in MODE 5 (Refuel) with any control rod withdrawn from a core cell containing one or more fuel assemblies. This change does not impact the safety of the plant or any of the safety analysis assumptions. The design function of the RPS Functions are to shutdown the reactor when required by initiating a reactor scram. This is only possible when control rods are withdrawn. Control rods withdrawn from a core cell containing no fuel assemblies do not affect the reactivity of the core. With all the rods inserted the Shutdown Margin Requirements (LCO 3.1.1) and the required one-rod-out interlock (LCO 3.9.2) ensure no event will occur. The Actions for inoperable equipment in Mode 5 are also revised to be consistent with the proposed Applicability. Since all control rods are required to be fully inserted during fuel movement (LCO 3.9.3), the proposed applicable conditions cannot be entered while moving fuel. The only possible core alteration is control rod withdrawal which is adequately addressed by the proposed actions. This change is consistent with NUREG-1433.

L_3 The Frequency for the Turbine First Stage Pressure Permissive Channel Calibration is being decreased from 6 months to 24 months. PBAPS operating history has shown this instrument to be continually reliable over a 24 month period. Therefore, it is acceptable to decrease the Frequency of this Surveillance. This change is also essentially consistent with NUREG-1433, which requires the SR to be performed on a refueling outage basis.

L_4 The proposed change will require only the control rods in core cells containing one or more fuel assemblies to be inserted if the applicable Action A, B, or C cannot be performed within the required Completion Times. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core cells and are, therefore, not required to be inserted. The removal of the four fuel bundles surrounding a control rod very significantly reduces the reactivity worth of the associated control rod to the point where removal of that rod no longer has the potential to cause a reactivity excursion. This fact is recognized in the design of the control rod velocity limiter which precludes removal of a rod prior to removal of the four adjacent bundles. This is also reflected on the proposed definition of CORE ALTERATIONS. This change is consistent with NUREG-1433.

L_5 Not used.

TECHNICAL CHANGFS - LESS RESTRICTIVE (continued)

L_6 The proposed change will relax the current Actions for the Condenser Vacuum Low Function if the channel or trip system cannot be placed in trip within the required Completion Time. The current Actions require the rods to be inserted or to reduce turbine load and close the main steam line isolation valves within 6 hours. The proposed change will require the plant to be brought to MODE 2 within 6 hours. This would put the plant in a Mode which is outside the Mode of Applicability. The Condenser Low Vacuum Function ensures the integrity of the main turbine condenser by decreasing the severity of the transient on the condenser. This Function is only required in Mode 1 because in Mode 2 the heat generation rate is low enough so that the other diverse RPS functions provide sufficient protection. Therefore, by placing the plant in Mode 2, the plant is in a Mode where protection from this Function is not required. Thus, carrying out the current Actions is not required to put the plant in a safe condition. This change is consistent with NUREG-1433.

L_7 The proposed change will relax the current Actions for the Main Steam Line Isolation Valve Closure Function if the channel or trip system cannot be placed in trip within the required Completion Time. The current Actions require the rods to be inserted immediately. The proposed change will require the plant to be brought to MODE 2 within 6 hours. This would put the plant in a Mode which is outside the Mode of Applicability. The Main Steam Line Isolation Valve Closure Function ensures the reactor is shutdown in the event of main steam line isolation valve closure which reduces the amount of heat generation by the reactor. This Function, along with the ECCS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. In Mode 2, this Function is not required because the heat generation rate is low enough that the other diverse RPS functions provide sufficient protection. Therefore, by placing the plant in Mode 2, the plant is in a Mode where protection from this Function is not required. Thus, carrying out the current Actions is not required to put the plant in a safe condition. This change is consistent with NUREG-1433.

L_8 This change proposes to add a Note to the 7 day Channel Functional Test Surveillance Requirement (SR 3.3.1.1.3), and the 184 day Channel Calibration (SR 3.3.1.1.11). The Note will allow the plant to enter Mode 2 from Mode 1 without performing the required Surveillance. The surveillance, however, must be performed within 12 hours after entering Mode 2. This is allowed because the testing

TECHNICAL CHANGES - LESS RESTRICTIVE

L_8 (cont'd) of the Mode 2 required IRM and APRM Functions cannot be performed in Mode 1 without utilizing jumpers, lifted leads, or movable links. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the Surveillance Requirement.

L_9 This change decreases the Surveillance Frequency for the performance of the APRM heat balance calibration from twice per week to once per week. This Surveillance Requirement ensures that the APRMs are accurately indicating the true core average power which is affected by LPRM sensitivity. The 7 day Surveillance frequency is acceptable, based on operating experience and the fact that only minor changes in LPRM sensitivity occur during this time frame. Also the most common outcome of the performance of a surveillance is the successful demonstration that the acceptance criteria are satisfied. This change is consistent with NUREG-1433.

L_{10} This change adds a note to the APRM heat balance calibration (SR 3.3.1.1.2) which states the Surveillance is not required to be met until 12 hours after Thermal Power ≥ 25% RTP. This is allowed because it is difficult to accurately determine core Thermal Power from 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). This change is consistent with NUREG-1433. The 12 hour time limit for performing the surveillance is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

L_{11} This change proposes to add a Note to the IRM High Flux Channel Calibration which allows the Surveillance to only be required to be met during entry into MODE 2 from MODE 1. Currently the Surveillance is required to be met throughout the controlled shutdown. This change only requires the surveillance to be met during the transition from Mode 2 to Mode 1. After this requirement has been met then maintaining overlap is not required (APRMs may be reading downscale once in MODE 2). This change is consistent with NUREG-1433.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L_{av} This change revises the Technical Specification setpoints for proposed Section 3.3 instrumentation to reflect Allowable Values consistent with the philosophy of NUREG-1433. These Allowable Values (to be included in Technical Specifications) and the Trip Setpoints (to be included in plant procedures) have been established consistent with the PECO Energy Instrument Setpoint Methodology or the General Electric (GE) Instrument Setpoint Methodology; the PBAPS Units 2 & 3 specific safety analysis limits as modified by NEDC-32183P, "Power Rerate Safety Analysis Report for Peach Bottom 2 & 3," dated May 1993; and the uncertainties associated with the PBAPS Units 2 & 3 instrumentation. The setpoint evaluation used actual PBAPS physical data and operating practices to ensure the validity of the resulting Allowable Values and Trip Setpoints. Changes resulting from the Power Rerate analyses and the effect on safety analysis limits were previously evaluated in the licensee amendment requests (93-12) for Power Rerate (letter dated June 23, 1993, from G.A. Hunger (PECo) to NRC). All changes to safety analysis limits, applied in the methodologies, were evaluated and confirmed as ensuring safety analysis licensing acceptance limits are maintained. All design limits, applied in the methodologies, were confirmed as ensuring that applicable design requirements of the associated systems are maintained. The methodologies used to derive the Allowable Values and Trip Setpoints are based on combining the uncertainties of the associated channels as documented in letter dated May 2, 1992 from G.A. Hunger (PECO Energy) to NRC responding to the Request for Additional Information Regarding Power Rerate Request dated March 29, 1994 (RAI-2). The methodologies used in the evaluation are consistent with the methodology used for Limerick Units 1 & 2 and documented in NEDC-31336, "General Electric Instrumentation Setpoint Methodology." The NRC approval of NEDC-31336 is documented in a Safety Evaluation Report transmitted by letter from B. Boger (NRC) to D. Roare (GE) dated February 9, 1993. In the methodologies, the Trip Setpoints take into consideration calibration accuracies which were specifically assumed in the PBAPS Unit 2 & 3 setpoint calculations. Plant calibration procedures will ensure the assumptions regarding calibration accuracy are maintained. The proposed Allowable Values and Trip Setpoints have been established from each design or safety analysis limit by accounting for instrument accuracy, calibration and drift uncertainties, as well as process measurement accuracy and primary element accuracy using the PECO Energy Instrument Setpoint Methodology or the GE Instrument Setpoint Methodology. The use of these methodologies for establishing Allowable Values and Trip Setpoints ensures design or safety analysis limits are not exceeded in the event of transients or accidents and accounts for uncertainties and environmental conditions.

ADMINISTRATIVE CHANGES

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result. the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 Existing Specifications 3.3.B.4 and 4.3.B.4 require Source Range Monitors (SRMs) to be Operable whenever control rods are withdrawn for startup or refueling. Proposed LCO 3.3.1.2 (Table 3.3.1.2-1) will require SRMs to be Operable at all times in Mode 2 prior to and during control rod withdrawal until the flux level is sufficient to maintain the Intermediate Range Monitor (IRM) on Range 3 or above. This more restrictive change is consistent with BWR Standard Technical Specifications, NUREG-1433.

M_2 Existing Specifications 3.3.B.4 and 4.3.B.4 require SRMs to have an observable count rate with a signal to noise ratio above the curve in Figure 3.3.1 (proposed Figure 3.3.1.2-1); however, the number of SRMs required during rod withdrawal may be reduced from 3 channels to 2 channels if the observed count rate is above 3 counts per second (cps). Proposed LCO 3.3.1.2 will also require an observable count rate with a signal to noise ratio above the curve in Figure 3.3.1.2-1 but will not allow a reduction in the number of Operable SRM channels if the count rate is above 3 cps. This more restrictive change is consistent with BWR Standard Technical Specifications, NUREG-1433. However, the number of required SRM channels during Mode 2 and during Core Alterations may be reduced to 2 or fewer during certain circumstances as discussed in the less restrictive changes for this section.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

M_3 Existing Specification 4.3.B.4 requires verification "prior to control rod withdrawal during startup" and Specification 3.10.B.1.b requires verification during "Alterations of the Core" that SRMs have an observable count rate with a signal to noise ratio above the curve shown in Figure 3.3.1 (proposed Figure 3.3.1.2-1). Proposed SR 3.3.1.2.4 has the same requirements; however, SR 3.3.1.2.4 will require periodic verification of the SRM count rate at least once per 24 hours while in Mode 5, Mode 4, and Mode 3 and in Mode 2 when IRMs are on Range 2 or below. Periodic verification of SRM count rate will be required every 12 hours during Core Alterations. This change is consistent with BWR Standard Technical Specifications, NUREG-1433.

M_4 Proposed LCO 3.3.1.2 will require 3 additional Surveillance Tests to demonstrate SRM Operability when the IRMs are on Range 2 or below in Mode 2. The proposed Surveillances are: SR 3.3.1.2.1 which will require performance of an SRM Channel Check every 12 hours; SR 3.3.1.2.6 which will require an SRM Channel Functional Test and determination of signal to noise ratios every 31 days; and, SR 3.3.1.2.7 which will require an SRM Channel Calibration every 184 days. Proposed SR 3.3.1.2.6 and SR 3.3.1.2.7 will be modified by a Note that will allow deferral of these Surveillances until 12 hours after the IRMs are on Range 2 or below when the reactor is being shutdown. SR 3.3.1.2.7 is also modified by a Note that excludes the neutron detectors from calibration requirements because the detectors are fission chambers that are designed to have a relatively constant sensitivity over the range and with an accuracy specified for a fixed useful life and cannot readily be adjusted. These additional requirements for testing of SRMs are consistent with BWR Standard Technical Specifications, NUREG-1433.

M_5 Existing Specifications do not have any requirements for SRM Operability during Mode 3 and Mode 4. Proposed LCO 3.3.1.2 (Table 3.3.1.2-1) will require 2 SRM channels to be Operable at all times in Mode 3 and Mode 4. Additionally, SRM Operability in Modes 3 and 4 must be demonstrated by the performance of proposed SR 3.3.1.2.3, SR 3.3.1.2.4, SR 3.3.1.2.6, and SR 3.3.1.2.7. Proposed LCO 3.3.1.2, Condition D, will require that all insertable control rods be fully

DISCUSSION OF CHANGES
ITS 3.3.1.2: SRM INSTRUMENTATION

<u>TECHNICAL CHANGES - MORE RESTRICTIVE</u>

M_5 (cont'd) inserted and the reactor mode switch be in the shutdown position within 1 hour if less than the 2 required SRM channels are Operable. The requirements for SRM Operability in Mode 3 and Mode 4 and the associated Surveillance Tests, Conditions, Required Actions and Completion Times are consistent with BWR Standard Technical Specifications, NUREG-1433.

M_6 Existing Specifications 3.10.B.1 and 3.10.B.5 establish requirements for the location of SRMs during Core Alterations and during core unloading and reloading. Proposed SR 3.3.1.2.2 will set similar requirements for SRM location during Core Alterations which because of a change in the Definition of Core Alteration will include core loading and unloading. Proposed SR 3.3.1.2.2 will add a new requirement to verify every 12 hours during Core Alterations that the SRMs are properly located. Additionally, SR 3.3.1.2.2 will require that one of the SRMs be located in "the fueled region" during all Core Alterations whereas the existing 3.10.B.5 required that one of the SRMs be located in "intermediate arrays of fuel" during the unloading and reloading of fuel. Finally, in both the existing and proposed specifications, only 2 SRMs are required to be Operable but three SRM location criteria are identified. Note 2 to proposed SR 3.3.1.2.2 will explicitly acknowledge that one SRM may be used to satisfy more than one location criteria. The proposed changes are consistent with BWR Standard Technical Specifications, NUREG-1433.

M_7 Proposed LCO 3.3.1.2 (Table 3.3.1.2-1) will require that Channel Functional Tests (proposed SR 3.3.1.2.5) be performed every 7 days when in Mode 5 instead of prior to core alterations and prior to core unloading and reloading as is currently required by Specifications 4.10.B.1 and 4.10.B.2. SR 3.3.1.2.5 will also add the requirement to determine signal to noise ratios once per 7 days. Additionally, proposed LCO 3.3.1.2 (Table 3.3.1.2-1) will require that Channel Checks (proposed SR 3.3.1.2.1) be performed every 12 hours when in Mode 5 instead of prior to unloading and reloading of fuel and prior to and daily during alterations of the core as is currently required by Specifications 4.10.B.1 and 4.10.B.2. Proposed SR 3.3.1.2.1 and SR 3.3.1.2.5 are more restrictive than the existing specifications. The proposed changes are consistent with BWR Standard Technical Specifications, NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

M_8 Proposed LCO 3.3.1.2 (Table 3.3.1.2-1 Mode 5 requirements) will add a new requirement to perform a Channel Calibration (proposed SR 3.3.1.2.7) every 184 days to verify the performance of the SRM detectors and associated circuitry. SR 3.3.1.2.7 will be modified by a Note that excludes the neutron detectors from calibration requirements because the detectors are fission chambers that are designed to have a relatively constant sensitivity over the range and with an accuracy specified for a fixed useful life and cannot readily be adjusted. Note 2 to proposed SR 3.3.1.2.7 will explicitly acknowledge that the Channel Calibration cannot be performed at power and will allow deferring performance until 12 hours after the IRMs are on Range 2 or below during a reactor shutdown. The proposed changes are consistent with BWR Standard Technical Specifications, NUREG-1433.

M_9 Existing specifications require that SRMs be Operable "during Alterations of the Core" and "prior to control rod withdrawal for startup or during refueling. Proposed LCO 3.3.1.2 (Table 3.3.1.2-1) will establish Operability requirements for SRMs at all times during Mode 3, Mode 4, and Mode 5 and during Mode 2 when the IRMs are on Range 2 or below. The proposed changes are consistent with BWR Standard Technical Specifications, NUREG-1433.

M_{10} Existing Specification 3.10.B does not identify Required Actions if SRM Operability requirements in Mode 5 are not satisfied; therefore, Specification 3.10.B defaults to LCO 3.0.C. Proposed LCO 3.3.1.2 will add Required Actions if less than the required number of SRMs are Operable in Mode 5. If one or more required SRMs are inoperable when in Mode 5, proposed LCO 3.3.1.2 Condition E will require that Core Alterations be terminated and action be taken immediately to fully insert all control rods. The proposed changes are consistent with BWR Standard Technical Specifications, NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS

R_1 Existing Specification 3.10.B.1.a requires that SRMs be inserted to the normal operating level during core alterations. Proposed specifications have requirements for minimum SRM count rate during Core Alterations but do not require that the SRMs be fully inserted. This existing requirement is being relocated to plant procedures to provide assurance it will be maintained. Changes to these procedures will be controlled by 10 CFR 50.59.

TECHNICAL CHANGES - RELOCATIONS (continued)

R_2 Existing Specification 3.10.B.1.b requires that the SRM minimum count rate during Core Alterations must be achieved with all rods fully inserted in the core. Proposed specifications have requirements for minimum SRM count rate during Core Alterations but do not specifically require that the control rods be fully inserted. This existing requirement is being relocated to plant procedures to provide assurance it will be maintained. Changes to these procedures will be controlled by 10 CFR 50.59.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 Existing Specification 3.3.B.4 does not identify Required Actions if SRM Operability requirements in Mode 2 are not satisfied; therefore, Specification 3.3.B.4 defaults to LCO 3.0.C which requires that the plant be in Hot Shutdown (Mode 3) within 6 hours. Proposed LCO 3.3.1.2 will identify the Required Actions and associated Completion Times if SRM Operability requirements in Mode 2 are not satisfied. Proposed Condition A will allow 4 hours to restore the 3 required SRM channels to Operable as long as at least one SRM is always Operable. Proposed Condition B will require suspension of all control rod withdrawal if there are no Operable SRMs; and, in accordance with Condition A, will allow 4 hours to make the required 3 SRM channels Operable. Proposed Condition C will require that the reactor be in Mode 3 within 12 hours if Required Actions and Completion Times for Condition A or B are not satisfied. Proposed Conditions A, B, and C are less restrictive than the existing specifications for the following reasons: Condition A will allow control rod withdrawal to continue for up to 4 hours with less than the required number of SRMs Operable; Condition A may be exited either by restoration of the required number of SRM channels or by increasing reactor power until the IRMs are above Range 2; Condition B will allow up to 4 hours to attempt to restore the required number of SRM channels before a reactor shutdown must be initiated; and, Conditions A, B and C allow up to 16 hours (4 hours for Conditions A and B and 12 hours for Condition C) before the reactor must be in Mode 3 when SRM Operability requirements are not satisfied (LCO 3.0.C requires that the plant be in Mode 3 within 6 hours). These changes are acceptable because: SRMs are not credited in the analysis of any accident and exist solely to allow operators to monitor changes in power level during startup; at least one SRM will remain Operable during any rod withdrawal; excessive reactivity additions during Mode 2 will be quickly identified and mitigated by

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 (cont'd) the IRMs, IRM rod blocks, and the IRM Range 1 High Flux Trip function; and, reactivity addition accidents from the source range are assumed to begin with flux below the level of source range detector sensitivity and the analysis assumptions are not affected by the operators ability to monitor changes in flux levels. These less restrictive Required Actions are consistent with BWR Standard Technical Specifications, NUREG-1433.

L_2 If a spiral offload or reload pattern is used, the proposed specifications will allow: 1) a reduction in the number of SRM channels required to be Operable during refueling; and, 2) an exemption from the requirements for minimum observable SRM count rate without having to electrically disarm all control rods in cells that contain fuel. Specifically, existing Specification 3.10.B.1 requires two SRMs during Core Alterations. Proposed Specification 3.3.1.2 (Table 3.3.1.2-1 footnote (b)) reduces the number of SRM channels required to be Operable from 2 to 1 "during spiral offload or reload when the fueled region includes only that SRM detector." A reduction in the number of required Operable SRM channels is acceptable when using a spiral pattern for loading or offloading fuel because the use of a spiral pattern provides assurance that the Operable SRM is in the optimum position for monitoring changes in neutron flux levels resulting from the Core Alteration. Additionally, existing Specification 3.10.B.2 permits the SRM count rate to fall below the specified minimum level if all control rods in cells that contain fuel are fully inserted and electrically disarmed. Proposed SR 3.3.1.2.4 relaxes the requirement for a minimum SRM count rate without having to electrically disarm control rods if a spiral unloading pattern is used. Reduced requirements for SRM minimum count rate are acceptable when using a spiral pattern for unloading fuel because the use of a spiral unloading pattern provides assurance that all fuel movement will result in decreasing core total reactivity and that the Operable SRM is in the optimum position for monitoring changes in neutron flux levels. These changes are consistent with BWR Standard Technical Specifications, NUREG-1433.

ADMINISTRATIVE CHANGES

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 Existing Specification 3.3.B.5 and Table 3.2.C (Note 1) specify that there shall be two Operable or tripped trip systems for each function of the Rod Block Monitor (RBM) system. Table 3.2.C column 1, "Minimum Number of Operable Instrument Channels per Trip System," requires 1 channel per trip system for the RBM. There are two trip systems each of which has one RBM instrument. Therefore, in accordance with existing Specifications 3.3.B.5, 3.2.C.2, and Table 3.2.C (Note 1), there must be two Operable RBM instruments and trip channels. Therefore, proposed LCO 3.3.2.1 (Table 3.3.2.1-1 Function 1, Rod Block Monitor) will require 2 Operable channels in the RBM system. This is an administrative change because the number of instrument channels and trip systems has not changed.

A_3 Existing Specifications 3.3.B.3.b.1 and 4.3.C.2 describe the control rod patterns that the Rod Worth Minimizer must enforce with the terms "prescribed control rod pattern" and "correctness of the control rod withdrawal sequence." Proposed LCO 3.3.2.1, Conditions C and D, and proposed SR 3.3.2.1.8 will identify the rod pattern that is enforced by the RWM as the banked position withdrawal sequence (BPWS) which will establish the required rod patterns as described in NEDO 21231, "Banked Position Withdrawal Sequence."

A_4 Existing Table 3.2.C (Note 11) states that the values for the Rod Block Monitor high trip setpoint, intermediate trip setpoint, low trip setpoint, and downscale trip setpoint are located in the Core Operating Limits Report (COLR). Proposed LCO 3.3.2.1 (Table 3.3.2.1-1) will also reference the COLR as the location of these limits.

ADMINISTRATIVE CHANGES (continued)

A_5 Notes preceding proposed SR 3.3.2.1.4 and 3.3.2.1.5 will permit the neutron detectors to be excluded from the RBM Functional Test and RBM Channel Calibration. The neutron detectors are excluded from these 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 3.3.1.1.8. Existing Table 4.2.C (Note 3) allows the use of a "simulated electrical signal" when performing a functional test or calibration of the Rod Block Monitors. This is equivalent to the proposed Note that excludes neutron detectors from testing. This change is consistent with BWR Standard Technical Specifications, NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 The proposed Specification 3.3.2.1, Control Rod Block Instrumentation, will include specific requirements in Table 3.3.2.1-1 for the RBM "Inop" function (proposed Function 1.d.) and RBM Timer Bypass (proposed Function 1.d.). These RBM functions, were included in the ARTS/MELLLA analysis for the RBM. ARTS/MELLLA analysis is documented NEDC-32162P, Rev.1, "Maximum Extended Load Line Limit and ART Improvement Program Analyses for Peach Bottoms Atomic Power Station Unit 2 and 3." The RBM Bypass Timer must be set to "minimum" because the current analysis does not support the use of the timer which is used to compensate for a noisy instrument channel that could prevent rod withdrawal. All Conditions, Required Actions, and Surveillance Tests for the RBM are also Applicable to the "Inop" and "Timer Bypass" functions of the RBM . This change is consistent with BWR Standard Technical Specifications, NUREG-1433.

M_2 Proposed Specification 3.3.2.1, Control Rod Block Instrumentation, will include the Control Rod Block Function of the Reactor Mode Switch as a required function (Function 3 on proposed Table 3.3.2.1-1). The new requirement is that 2 channels of the Rod Block function of Reactor Mode Switch -- Shutdown Position must be Operable whenever the Mode Switch is in the Shutdown position. This addition to the specification for the Control Rod Block Instrumentation will include proposed SR 3.3.2.1.7 (Channel Functional Test every 24 months) and proposed LCO 3.3.2.1, Condition E (Required Actions and Completion Times if this function is inoperable). Proposed SR 3.3.2.1.7 will not be required to be performed until 1 hour after the Reactor Mode Switch is placed in Shutdown. This change is consistent with BWR Standard Technical Specifications, NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

M_3 Existing specifications require that the Rod Block Monitor must be Operable: "During operations with limiting control rod patterns, as determined by qualified personnel" (3.3.B.5); "For Startup and Run Positions of the Reactor Mode Switch" except that "RBM rod blocks need not be Operable in 'Startup' mode" (Table 3.2.C, Note 1); and, RBM "trip is bypassed when reactor power is ≤ 30%" (Table 3.2.C Note 7). Proposed Specification 3.3.2.1, Control Rod Block Instrumentation, will identify the Applicability for the RBM in Footnotes (a), (b), (c), (d), and (e) which can be summarized as the RBM must be Operable when Thermal Power is ≥ 28.3% and ≤ 90% when MCPR is less than the limit specified in the COLR and when Thermal Power is ≥ 90% when MCPR is less than the limit specified in the COLR. The proposed Applicability was determined by the ARTS analysis for the RBM (NEDC-32162P, Rev.1, "Maximum Extended Load Line Limit and ART Improvement Program Analyses for Peach Bottoms Atomic Power Station Unit 2 and 3" and GE-NE-901-0293, Rev.1, "APRM, RBM, and Technical Specifications (ARTS) Setpoint Calculations for Philadelphia Electric Company Peach Bottom 2,3"). This change is consistent with BWR Standard Technical Specifications, NUREG-1433.

M_4 Proposed Specification 3.3.2.1 will include an additional surveillance (SR 3.3.2.1.6) to verify every 24 months that the Rod Worth Minimizer (RWM) is not bypassed when Thermal Power is ≤ 10%. Both existing Specification 3.3.B.3.b and proposed Specification 3.3.2.1 (Table 3.3.2.1-1 Footnote (f)) specify that the RWM function is only required to be Operable when Thermal Power is less than 10% and the RWM is automatically bypassed when power is above 10%. However, the existing specifications do not have an explicit requirement to verify the setpoint of the RWM bypass feature. This change is consistent with BWR Standard Technical Specifications, NUREG-1433.

M_5 This SR has been deleted since it is covered by the combination of proposed SRs 3.3.2.1.1, 3.3.2.1.4, and 3.3.2.1.5. In addition, these SRs are performed at a Frequency no greater than 184 days, therefore this change is considered more restrictive.

TECHNICAL CHANGES - RELOCATIONS

R_1 Existing Specifications 2.1.B, 3.2.C.2.1, and 4.2.C.2.1 include the Safety Limits, LCOs and SRs for Rod Block functions associated with the APRMs, IRMs, SRMs, and Scram Discharge Volume Level. These requirements are being relocated to PBAPS plant procedures and will be controlled in accordance with 10 CFR 50.59. Only the power-biased local power RBM functions are being retained in Technical Specifications. The APRM, IRM, SRM, and Scram Discharge Volume (SDV) rod blocks are intended to prevent control rod withdrawal when plant conditions make such withdrawal imprudent. However, there are no safety analyses that depend upon these rod blocks to prevent, mitigate or establish initial conditions for design basis accidents or transients. The evaluation summarized in NEDO 31466 determined that the loss of the APRM, IRM, SRM, and scram discharge volume rod blocks would be a non-significant risk contributor to core damage frequency and offsite releases. The results of this evaluation have also been determined to be applicable to PBAPS Units 2 and 3. Therefore, this instrumentation did not satisfy the NRC Policy Statement on Technical Specification Screening Criteria for inclusion in the Technical Specifications and will be relocated to plant procedures and controlled in accordance with 10 CFR 50.59.

R_2 Existing Table 3.2.C includes the "Number of Instrument Channels Provided by Design." This information will be relocated to the Applicable Safety Analyses section of the proposed Bases for Specification 3.3.2.1. This change is consistent with BWR Standard Technical Specifications, NUREG-1433.

R_3 Existing Table 4.2.C, Notes 4 and 6 contain details regarding the performance of Rod Block Monitor Surveillance Tests. Details of the methods for performing Surveillance Tests will be relocated to plant procedures and will be controlled in accordance with 10 CFR 50.59.

R_4 Existing Specifications 4.3.B.3.b.1.a, b, and c contain details related to the performance of the Rod Worth Minimizer (RWM) Channel Functional Test. Details of the methods for performing Surveillance Tests will be relocated to plant procedures and will be controlled in accordance with 10 CFR 50.59.

R_5 Existing Specification 4.2.C.2 (Table 4.2.C) requires an "Instrument Check" of the Rod Block Monitor once/day. This test is performed by comparison of redundant channels as a simple check of instrument performance. NUREG-1433 has no equivalent check for the RBM so performance of the daily "Instrument Check" of the Rod Block Monitor will be relocated to plant procedures and will be controlled in accordance with 10 CFR 50.59.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 Proposed LCO 3.3.2.1, Conditions A and B, will extend the Completion Time for blocking control rod withdrawal if one RBM channel is inoperable from immediately to within 25 hours. Additionally, proposed LCO 3.3.2.1, Condition B, will extend the Completion Time for blocking control rod withdrawal if both RBM channels are inoperable from immediately to within 1 hour. However, the requirement to block control rod withdrawal if a RBM channel is inoperable will exist whenever the RBM function is required to be Operable and not just "during operation with limiting control rod patterns" as is required by existing Specification 3.3.B.5. These proposed changes are to existing Specification 3.3.B.5. which, if one or both Rod Block Monitor (RBM) channels are inoperable when "limiting control rod patterns" exist, requires blocking all control rod withdrawal or adjusting thermal power to a level where the RBM system is not required to be Operable. The proposed increase in the amount of time allowed to block control rod withdrawal if one RBM channel is inoperable is acceptable because the remaining Operable channel is adequate to perform the control rod block function but the change does not allow continued operation in a configuration where a single failure will result in the loss of the control rod block function. The 1 hour Completion Time to block control rod withdrawal if both RBM channels are inoperable is intended to allow the operator time to evaluate and repair any discovered inoperabilities and is acceptable because it strictly limits the amount of time operation may continue with a complete loss of the RBM function while allowing time for restoration or tripping of inoperable channels. This change is consistent with BWR Standard Technical Specifications, NUREG-1433.

L_2 Existing Specification 4.3.B.3.b.1 requires a Channel Functional Test of the Rod Worth Minimizer (RWM) "prior to the start of control rod withdrawal toward criticality" and "prior to attaining the Rod Worth Minimizer low power setpoint during rod insertion." Proposed Specification 3.3.2.1 will require a Channel Functional Test of the RWM every 92 days in Mode 2 and every 92 days in Mode 1 when Thermal Power is ≤ 10%. Proposed SR 3.3.2.1.2 will be modified by a Note stating that the Channel Functional Test is not required during a startup until 1 hour after any control rod is withdrawn at ≤ 10% RTP in Mode 2. Proposed SR 3.3.2.1.3 will be modified by a Note stating that the Channel Functional Test is not required during a shutdown until 1 hour after Thermal Power is ≤10% in Mode 2. The addition of these Notes make the proposed requirement for a Channel Functional Test less restrictive because the Surveillance Test is not required

TECHNICAL CHANGES - LESS RESTRICTIVE

L_2 (cont'd) until 1 hour after the RWM is required to be Operable. These changes are acceptable for the following reasons: a) the Rod Worth Minimizer does not monitor core thermal conditions but simply enforces preprogrammed rod patterns as a backup intended to prevent reactor operator error in selecting or positioning control rods; b) reliability analysis documented in NEDC-30851-P-A, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," October 1988 determined that the failure frequency curve for this instrumentation is relatively flat in the range of 30 to 124 days and starts a gradual increase after 124 days which means that more frequent testing is unlikely to identify problems; and, c) it is overly conservative to assume that the RWM is not Operable when a surveillance is not performed because of its demonstrated reliability as demonstrated by successful completion of most Channel Functional Tests. This change is consistent with BWR Standard Technical Specifications, NUREG-1433.

L_3 The proposed change eliminates Specification 4.3.B.5 which requires a Functional Test of the Rod Block Monitor (RBM) "prior to withdrawal of the designated rod(s)" whenever "a limiting control rod pattern exists" and relies completely upon the Functional Test which is required every 92 days. The proposed change is acceptable because: two independent RBM channels will be Operable during any rod withdrawal except for short and infrequent periods when one channel is inoperable; and, deletion of this requirement allows taking credit for routine periodic tests in place of performing unscheduled testing whenever the potential exists that the RBM may be required to function. The Frequency of 92 days for the Channel Functional Test is based upon the reliability analysis in NEDC-30851-P-A, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," October 1988. This reliability study found that the failure frequency curve for this type of instrumentation is relatively flat in the range of 30 to 124 days and starts a gradual increase after 124 days. Based on this finding, performing this testing more frequently than every 92 days does not significantly increase the probability of detecting a random failure of the RBM. This change is consistent with BWR Standard Technical Specifications, NUREG-1433.

<u>TECHNICAL CHANGES - LESS RESTRICTIVE</u> (continued)

L_{av} This change revises the Technical Specification setpoints for proposed Section 3.3 instrumentation to reflect Allowable Values consistent with the philosophy of NUREG-1433. These Allowable Values (to be included in Technical Specifications) and the Trip Setpoints (to be included in plant procedures) have been established consistent with the PECO Energy Instrument Setpoint Methodology or the General Electric (GE) Instrument Setpoint Methodology; the PBAPS Units 2 & 3 specific safety analysis limits as modified by NEDC-32183P, "Power Rerate Safety Analysis Report for Peach Bottom 2 & 3," dated May 1993; and the uncertainties associated with the PBAPS Units 2 & 3 instrumentation. The setpoint evaluation used actual PBAPS physical data and operating practices to ensure the validity of the resulting Allowable Values and Trip Setpoints. Changes resulting from the Power Rerate analyses and the effect on safety analysis limits were previously evaluated in the licensee amendment requests (93-12) for Power Rerate (letter dated June 23, 1993, from G.A. Hunger (PECo) to NRC). All changes to safety analysis limits, applied in the methodologies, were evaluated and confirmed as ensuring safety analysis licensing acceptance limits are maintained. All design limits, applied in the methodologies, were confirmed as ensuring that applicable design requirements of the associated systems are maintained. The methodologies used to derive the allowable Values and Trip Setpoints are based on combining the uncertainties of the associated channels as documented in letter dated May 2, 1994 from G.A. Hunger (PECO Energy) to NRC responding to the Request for Additional Information Regarding Power Rerate Request dated March 29, 1994 (RAI-2). The methodologies used in the evaluation are consistent with the methodology used for Limerick Units 1 & 2 and documented in NEDC-31336, "General Electric Instrumentation Setpoint Methodology." The NRC approval of NEDC-31336 is documented in a Safety Evaluation Report transmitted by letter from B. Boger (NRC) to D. Roare (GE) dated February 9, 1993. In the methodologies, the Trip Setpoints take into consideration calibration accuracies which were specifically assumed in the PBAPS Unit 2 & 3 setpoint calculations. Plant calibration procedures will ensure the assumptions regarding calibration accuracy are maintained. The proposed Allowable Values and Trip Setpoints have been established from each design or safety analysis limit by accounting for instrument accuracy, calibration and drift uncertainties, as well as process measurement accuracy and primary element accuracy using the PECO Energy Instrument Setpoint Methodology or the GE Instrument Setpoint Methodology. The use of these methodologies for establishing Allowable Values and Trip Setpoints ensures design or safety analysis limits are not exceeded in the event of transients or accidents and accounts for uncertainties and environmental conditions.

ADMINISTRATIVE CHANGES

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 Proposed LCO 3.3.2.2, Feedwater and Main Turbine High Water Level Trip Instrumentation, and the associated Conditions, Required Actions, Completion Times, and Surveillance Requirements have been added. The feedwater and main turbine high water level trip instrumentation is assumed to be capable of providing feedwater and main turbine high water level trips in the design basis transient analysis for a feedwater controller failure, maximum demand event. Justification for the allowable out of service times for inoperable instrument channels and the minimum frequency for channel functional tests is provided by GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications" (SER dated July 21, 1992). Confirmation of the applicability of GENE-770-06-1 to PBAPS is documented in Attachment 1 to the 10 CFR 50.59 Safety Assessment for Technical Specification Change Request 90-03. The proposed 24 month frequency for channel calibration and the associated allowable value leave the channel adjusted to account for instrument drift between successive calibrations, consistent with the assumptions of the current plant specific setpoint methodology. This proposed additional restriction is consistent with NUREG-1433 and helps ensure the safety analysis assumptions are maintained.

TECHNICAL CHANGES - RELOCATIONS

None

TECHNICAL CHANGES - LESS RESTRICTIVE

None

Specification 3.3.3.1

Unit 2

~~NOTES FOR TABLE 3.2.F~~ A1

A1 Action A ~~1)~~ From and after the date that one of these parameters is reduced to one indication, continued operation is permissible during the succeeding thirty days unless such instrumentation is sooner made operable.

A1 Action C ~~2)~~ From and after the date that one of these parameters is not indicated in the control room, continued operation is permissible during the succeeding seven days unless such instrumentation is sooner made operable.

L1 Action B 3) ~~If the requirements of notes (1) and (2) cannot be met, an orderly shutdown shall be initiated and the reactor shall be in a cold condition within 24 hours.~~

Action E L2 4) ~~These surveillance instruments are considered to be redundant to each other.~~

5) ~~If this parameter is not indicated in the control room, either restore at least one channel to operable status within thirty days or be in at least Hot Shutdown within the next 12 hours.~~ R1

Table 3.3.3.1-1 Note (c) 6) A suppression chamber water temperature instrument channel will be considered operable if there are at least ten (10) resistance temperature detector inputs operable and no two (2) adjacent resistance temperature detector inputs are inoperable.

A1 ~~7)~~ With the number of operable channels less than the minimum number of instrument channels shown in Table 3.2.F, initiate the preplanned alternate method of monitoring the appropriate parameter ~~within 72 hours~~ and:

L3 Action A

L3 L4

Action C ~~a)~~ either restore the inoperable channel(s) to operable status within 7 days of the event, or

Actions B, F, & Specification 5.6.7 ~~b)~~ 6 prepare and submit a Special Report to the Commission within 10 working days following the event, outlining the action taken, the cause of the inoperability, and the plans and schedule for restoring the system to operable status. A1

A1 Action A ~~8)~~ With the number of operable channels less than the minimum number of instrumentation channels shown in Table 3.2.F, continued operation is permissible during the succeeding thirty days. ~~Provided both Drywell Pressure instruments (0-70 psig) are operable; otherwise, restore the inoperable channel to operable status within 7 days or be in at least Hot Shutdown within the next 12 hours.~~ L5

Action B L1

B

~~NOTES FOR TABLE 3.2.F~~ (A1)

(A1) Action A 1) From and after the date that one of these parameters is reduced to one indication, continued operation is permissible during the succeeding thirty days unless such instrumentation is sooner made operable.

(A1) Action C 2) From and after the date that one of these parameters is not indicated in the control room, continued operation is permissible during the succeeding seven days unless such instrumentation is sooner made operable.

(L1) Action B, Action E 3) If the requirements of notes (1) and (2) cannot be met, an orderly shutdown shall be initiated and the reactor shall be in a cold condition within 24 hours.

(L2) ~~4) These surveillance instruments are considered to be redundant to each other.~~

~~5) If this parameter is not indicated in the control room, either restore at least one channel to operable status within thirty days or be in at least Hot Shutdown within the next 12 hours.~~ (R1)

Table 3.3.3.1-1 Note (c) 6) A suppression chamber water temperature instrument channel will be considered operable if there are at least ten (10) resistance temperature detector inputs operable and no two (2) adjacent resistance temperature detector inputs are inoperable.

(A1) 7) With the number of operable channels less than the minimum number of instrument channels shown in Table 3.2.F, initiate the preplanned alternate method of monitoring the appropriate parameter within 72 hours and: (L3) Action A (L4) (L3)

Action C a) either restore the inoperable channel(s) to operable status within 7 days of the event, or

Actions B, F, & Specification 5.6.7 (A1) (L6) b) prepare and submit a Special Report to the Commission within 10 working days following the event, outlining the action taken, the cause of the inoperability, and the plans and schedule for restoring the system to operable status.

(A1) Action A 8) With the number of operable channels less than the minimum number of instrumentation channels shown in Table 3.2.F, continued operation is permissible during the succeeding thirty days, provided both Drywell Pressure instruments (0-70 psig) are operable; otherwise, restore the inoperable channel to operable status within 7 days or be in at least Hot Shutdown within the next 12 hours. (L5)

Action B (L1)

DISCUSSION OF CHANGES
ITS 3.3.3.1: PAM INSTRUMENTATION

ADMINISTRATIVE CHANGES

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. During this reformatting and renumbering process, no technical changes (either actual or interpretational) to the TS were made unless they were identified and justified.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 An Applicability for Post Accident Monitoring (PAM) instrumentation has been specified consistent with the required function of the instrumentation. PAM instrumentation is required to monitor variables related to the diagnosis and preplanned actions required to mitigate design basis accidents which are assumed to occur in MODES 1 and 2. As such, the Applicability has been specified as MODES 1 and 2. The change is considered administrative in nature since in general the existing shutdown requirements associated with PAM instrumentation being retained in Technical Specifications reflect placing the unit in MODE 3 (the non-applicable Mode). The shutdown actions for those instruments that are not consistent with this Applicability will be addressed separately.

A_3 Two Notes have been provided which modify the Actions of the PAM Specification. Note 1 states that the provisions of LCO 3.0.4 are not applicable. As a result, a Mode change is allowed when PAM instrumentation is inoperable. This allowance is provided due to the passive function of the instruments, the operator's ability to diagnose an accident using alternative instruments and methods and the low probability of an event requiring the use of these instruments. Adding Note 1 is considered an administrative change because existing PBAPS Technical Specifications do not have a requirement that prohibits entry into a Mode or condition when an LCO required by that Mode or condition is not satisfied. Therefore, existing Technical Specifications already allow the actions

ADMINISTRATIVE CHANGES

A_3 (cont'd) permitted by Note 1. Note 2 provides more explicit instructions for proper application of the Actions for Technical Specifications compliance. In conjunction with the proposed Specification 1.3 - "Completion Times," the Note ("Separate Condition entry is allowed for each Function") provides direction consistent with the intent of the existing Action for an inoperable PAM instrumentation channel. Since Note 2 only provides more explicit direction of the current interpretation of the existing specifications, this change is considered administrative.

A_4 A new Action D was added to direct the user to the appropriate Condition when the Required Action and associated Completion Time of Condition C is not met. This addition is an administrative change consistent with NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 Requirements for PCIV position indication have been added. These requirements include an LCO, Applicability, Actions, and Surveillance Requirements. Requirements for PCIV position indication are included consistent with NUREG-1433 guidelines to include all Type A and Category 1 PAM instruments.

M_2 The Applicability for the oxygen analyzers has been expanded from "power operation" to "Modes 1 and 2." This change achieves consistency with the CAD System and NUREG-1433 and represents an additional restriction on plant operations.

TECHNICAL CHANGES - RELOCATIONS

R_1 The NRC position on application of the deterministic screening criteria to PAM instrumentation is documented in a letter dated May 7, 1988 from T.E. Murley (NRC) to R.F. Janecek (BWROG). The position was that the PAM table in Technical Specifications should contain, on a plant specific basis, all Regulatory Guide 1.97 Type A instruments and all Category 1 instruments. Accordingly, this position has been applied to the PBAPS Unit 2 and 3 Regulatory Guide 1.97 instruments. Those instruments meeting this criteria have remained in Technical Specifications. The instruments not meeting this criteria, and their associated Technical Specification

TECHNICAL CHANGES - RELOCATIONS

R_1 (cont'd) requirements have been relocated to plant controlled documents, controlled using 10 CFR 50.59. For PAM instrumentation, that does not satisfy the deterministic screening criteria, their loss is not considered risk significant since the variable they monitor did not qualify as a Type A or Category 1 variable (one that is important to safety or needed by the operator to perform necessary manual actions). Therefore, consistent with NUREG-1433, these criteria have been applied to the PBAPS specific PAM instrumentation and the following instruments and their associated requirements are being relocated to plant controlled documents, controlled by 10 CFR 50.59.

1. Reactor Water Level (Narrow Range)
2. Drywell Pressure
3. Drywell Temperature
4. Suppression Chamber Water Level (Narrow Range)
5. Control Rod Position
6. Neutron Monitoring
7. Safety-Relief Valve Position Indication
8. Main Stack High Range Radiation Monitor
9. Reactor Building Roof Vent High Range Radiation Monitor

R_2 Details of the system Operability requirements and description of the instruments are relocated to the Bases, procedures, and the UFSAR. Placing this information in these documents provides assurance it will be maintained. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Process in Chapter 5 of the Technical Specifications.

R_3 Details of the performance of surveillances have been relocated to plant procedures. Placing these details in procedures provides assurance they will be maintained since changes to these procedures is controlled by 10 CFR 50.59. This change is consistent with NUREG-1433.

R_4 This Surveillance is being relocated to plant procedures since it is currently performed every time the CAD System is tested per existing Specification 4.7.A.6.a. As such, it does not need to be specified as a specific Surveillance Requirement. If during use of the system it was found to be inoperable, the appropriate Actions would be taken. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 Proposed Condition B of Specification 3.3.3.1 provides Action when a channel is not restored to Operable status in 30 days as required by Condition A. The Action of Condition B specifies initiating action in accordance with Specification 5.6.6. The action to submit a report is appropriate, in lieu of the existing shutdown requirement, when one PAM channel has not been restored to Operable status, given the likelihood of unit conditions that would require the information that is provided by this instrumentation and the fact that the report identifies alternative actions to be taken before a complete loss of functional capability can occur. 5

L_2 PAM instruments are provided to assist in the diagnosis and preplanned actions required to mitigate design basis accidents which are assumed in Modes 1 and 2. The probability of an event in Modes 3, 4, or 5 that would require PAM instrumentation is sufficiently low that PAM instruments are not required in these Modes. As a result, for PAM instruments, the appropriate non-applicable Mode for shutdown actions is Mode 3. The Action to be in Mode 4 if at least one of the two Reactor Pressure or Suppression Chamber Water Temperature channels can not be restored to Operable status within the appropriate time has been revised to reflect placing the unit in the non-applicable Mode (Mode 3).

L_3 The Action for a single inoperable Drywell High Range Radiation channel has been revised. Thirty days are proposed to allow for restoration of the inoperable channel or initiation of the alternate method of monitoring per proposed Condition B. The change from 72 hours for initiation of the alternate monitoring method and 7 days for restoration of the inoperable channel to 30 days for both actions is acceptable based on the availability of the remaining Operable Drywell High Range Radiation channel or Operable diverse instrument channels, the passive nature of the instrument (no required automatic action) and the low probability of an event requiring the PAM instrumentation during the interval.

L_4 The Actions have been changed for two Drywell High Range Radiation channels inoperable. Seven days are proposed to be allowed for restoration of one channel prior to initiating the alternate method of monitoring, instead of the existing requirement for initiation of the alternate method of monitoring within 72 hours and restoration of two channels to Operable status. The Completion Time of 7 days for restoration of one channel or initiation of the alternate method of monitoring is considered acceptable based on the relatively low probability of an event requiring PAM instrumentation, the passive function of the instruments, and the availability of alternate means to obtain the information.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L_5 The current restrictions on the allowed outage times for one or two instrument channels inoperable which require the availability of other instruments to monitor the affected variables have been deleted from the Specifications. The proposed Actions provide adequate assurance that information is available to the operator based on the availability of the remaining Technical Specifications monitoring channel (for the Condition of one channel inoperable) or the alternate monitoring methods (for the Condition of two channels inoperable). As such, no requirements for the availability of specific instruments need be specified for these Conditions.

L_6 The Instrument Checks performed once each shift and once per day have been replaced by a Channel Check performed once per 31 days. The change is made to conform to NUREG-1433 and is acceptable given the passive nature of these devices and the fact that the most common outcome of the performance of a surveillance is demonstrating the acceptance criteria are satisfied.

L_7 The Actions for one and two inoperable oxygen analyzer channels have been revised. Thirty days are proposed to be allowed for restoration of a single channel and seven days are proposed to be allowed for restoration of one channel when two channels are inoperable. The change to the allowed outage times are considered acceptable based on the availability of the remaining Operable channel (one channel inoperable condition) or Operable diverse instrument channels (two channel inoperable condition), the passive nature of the instruments (no required automatic action) and the low probability of an event requiring PAM instrumentation during the intervals.

ADMINISTRATIVE CHANGES

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 Existing Specifications 3.11.C and 4.11.C identify requirements for the Emergency Shutdown Control Panel. These requirements are limited to an LCO that the Emergency Shutdown Control Panels be secured at all times and Surveillances to verify by visual inspection once per week that the panels are secured and to perform an electrical check once per refueling outage. A new Specification, 3.3.3.2, Remote Shutdown System will be added to require that the appropriate number of Functions are available to shutdown and control the plant if the control room must be evacuated. Appropriate Actions and Surveillance Requirements are also being added. This change is consistent with BWR Standard Technical Specifications, NUREG-1433, and represents an additional restriction on plant operations.

TECHNICAL CHANGES - RELOCATIONS

R_1 Existing Specifications 3.11.C and 4.11.C requires that the Emergency Shutdown Control Panels be secured at all times and that this status be verified once per week by visual inspection. Keeping the Emergency Shutdown Control Panels secured is intended to prevent inadvertent operation. These requirements are being relocated to

TECHNICAL CHANGES - RELOCATIONS

R_1 (cont'd) PBAPS plant procedures and will be controlled in accordance with 10 CFR 50.59. There are no safety analyses that depend upon these panels being secured to prevent, mitigate or establish initial conditions for design basis accidents or transients.

TECHNICAL CHANGES - LESS RESTRICTIVE

None

DISCUSSION OF CHANGES
ITS 3.3.4.1: ANTICIPATED TRANSIENT WITHOUT SCRAM
RECIRCULATION PUMP TRIP (ATWS-RPT) INSTRUMENTATION

ADMINISTRATIVE CHANGES

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 A proposed Note at the start of the Actions Table ("Separate Condition entry is allowed for each channel.") provides more explicit instructions for proper application for the new Actions for Technical Specification compliance. In conjunction with the proposed Specification 1.3 "Completion Times," this Note provides direction consistent with the intent of the Required Actions for inoperable ATWS-RPT channels, functions, trip systems or recirculation pump breakers. It is intended that each Required Action be applied regardless of it having been applied previously for other inoperable ATWS-RPT channels, functions, trip systems or recirculation pump breakers.

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 The required Frequency for performance of an ATWS-RPT Channel Check will be increased from once per day specified in existing specification 4.2.G (Table 4.2.G) to the once per 12 hours specified in proposed SR 3.3.4.1.1. The purpose of the channel check is to ensure that a gross failure of instrumentation has not occurred. Thus, performance of the channel check guarantees that undetected outright channel failure is limited to 12 hours. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS

R_1 Existing Specification 3.2.G establishes requirements for the Anticipated Transient Without Scram (ATWS) functions "Alternate Rod Insertion and Recirculation Pump Trip." Proposed Specification 3.3.4.1 will maintain the Technical Specifications requirement for the recirculation pump trip. However, the ATWS Alternate Rod Insertion (ARI) function, serving only as a backup to the Reactor Protection System Scram function, did not satisfy the NRC Policy Statement on Technical Specification Screening Criteria for inclusion in the Technical Specifications. As such, ARI function requirements are being relocated to a licensee controlled document. In addition to being controlled in accordance with 10 CFR 50.59, the ARI function is required by and must meet the requirements of 10 CFR 50.62 and will be maintained in accordance with Appendix B to 10 CFR 50 per NRC Generic Letter 85-06, "Quality Assurance Guidance for ATWS Equipment that is not Safety-Related." This proposed change is consistent with NUREG-1433.

R_2 Existing Specification 3.2.G establishes the requirement that the Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) function have "manual" actuation capability. However, manual actuation of the ATWS-RPT function is not credited in the ATWS analysis; as such, ATWS-RPT manual actuation function requirements are being relocated to the a licensee controlled document. Requirements for the manual actuation capability of the ATWS-RPT function will be controlled in accordance with 10 CFR 50.59. This proposed change is consistent with NUREG-1433.

R_3 Existing Specification 3.2.G includes the phrase "automatic actuation of logic and actuation devices" when describing the features of the ATWS-RPT function that must be Operable for the ATWS-RPT function to be Operable. This type of information will be relocated to the Bases in the section entitled Applicable Safety Analyses, LCO, and Applicability and will be controlled in accordance with 10 CFR 50.59. This change is consistent with NUREG-1433.

R_4 Existing Specification 3.2.G (Table 3.2.G, Column 4) includes the "Number of Instrument Channels Provided by Design per Trip System." Additionally, existing Specification 4.2.G (Table 4.2.G Note 2) identifies the ATWS-RPT function instruments as the same instruments used by the Core and Containment Cooling Systems. This type of information will be relocated to plant procedures and design documents and will be controlled in accordance with 10 CFR 50.59. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS (continued)

R_5 Existing Specification 4.2.G (Table 4.2.G including Note 2) establishes a requirement to perform every 3 months a Logic System Functional Test of the ATWS-RPT function without tripping the recirculation pump breaker. This requirement was placed in PBAPS Technical Specifications as a result of NRC SER dated 12/21/1988 that evaluated PBAPS compliance with the ATWS rule and recommended that the ATWS trip units and logic systems be tested once per quarter. Proposed SR 3.3.4.1.2 and 3.3.4.1.5 will require an ATWS-RPT Channel Functional Test once per 92 days and a Logic System Functional Test once per 24 months. Performance every 3 months of a Logic System Functional Test of the ATWS-RPT function without tripping the recirculation pump breaker provides additional assurance of proper operation of the trip units and logic systems but is not required by NUREG-1433. Since this additional requirement for testing can be adequately controlled by administrative procedures, this testing requirement will be relocated to plant procedures and controlled in accordance with 10 CFR 50.59. This change is consistent with NUREG-1433.

R_6 System operational details (when not to place in trip) have been relocated to the Bases and procedures. These details are unnecessary in the LCO and can be adequately controlled in the Bases and procedures. Changes to the Bases will be controlled by the provisions of the Bases Control Process in Chapter 5 of the Technical Specifications. Changes to procedures will be controlled by the provisions of 10 CFR 50.59.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 The Applicability requirement in proposed Specification 3.3.4.1 for the ATWS Recirculation Pump Trip will be at all times in Mode 1 instead of at all times in "Run or Startup Mode" as is required by existing Specification 3.2.G. The ATWS-RPT function is required to mitigate the consequences of a common mode failure of the Reactor Protection System scram function. The ATWS-RPT function reduces reactor power by tripping the recirculation pump breakers to reduce core flow. This function is required to be Operable in Mode 1 because the reactor may be producing significant power and the recirculation system could be at high flow. The function is not required in Startup (Mode 2) because the reactor is at low power and the recirculation system is at low flow; thus, both the need for and

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 (cont'd) the effectiveness of the ATWS-RPT function in Mode 2 is significantly reduced. A commensurate change is also proposed which revises the shutdown action (proposed Required Action D.2) to be consistent with placing the unit in a Mode outside the Applicability. This proposed change is consistent with NUREG-1433.

L_2 An additional Required Action is proposed to allow removal of the associated recirculation pump from service. Since this action accomplishes the functional purpose of the instrumentation and enables continued operation in a previously approved condition, the change is considered acceptable.

L_{av} This change revises the Technical Specification setpoints for proposed Section 3.3 instrumentation to reflect Allowable Values consistent with the philosophy of NUREG-1433. These Allowable Values (to be included in Technical Specifications) and the Trip Setpoints (to be included in plant procedures) have been established consistent with the PECO Energy Instrument Setpoint Methodology of the General Electric (GE) Instrument Setpoint Methodology; the PBAPS Units 2 & 3 specific safety analysis limits as modified by NEDC-32183P, "Power Rerate Safety Analysis Report for Peach Bottom 2 & 3," dated May 1993; and the uncertainties associated with the PBAPS Units 2 & 3 instrumentation. The setpoint evaluation used actual PBAPS physical data and operating practices to ensure the validity of the resulting Allowable Values and Trip Setpoints. Changes resulting from the Power Rerate analyses and the effect on safety analysis limits were previously evaluated in the licensee amendment requests (93-12) for Power Rerate (letter dated June 23, 1993, from G.A. Hunger (PECo) to NRC). All changes to safety analysis limits, applied in the methodologies, were evaluated and confirmed as ensuring safety analysis licensing acceptance limits are maintained. All design limits, applied in the methodologies, were confirmed as ensuring that applicable design requirements of the associated systems are maintained. The methodologies used to derive the Allowable Values and Trip Setpoints are based on combining the uncertainties of the associated channels as documented in letter dated May 2, 1994 from G.A. Hunger (PECO Energy) to NRC responding to the Request for Additional Information Regarding Power Rerate Request dated March 29, 1994 (RAI-2). The methodologies used in the evaluation are consistent with the methodology used for Limerick Units 1 & 2 and documented in NEDC-31336, "General Electric Instrumentation Setpoint Methodology." The NRC approval of NEDC-31336 is documented in a Safety Evaluation Report transmitted

TECHNICAL CHANGES - LESS RESTRICTIVE

L_{av} (cont'd) by letter from B. Boger (NRC) to D. Roare (GE) dated February 9, 1993. In the methodologies, the Trip Setpoints take into consideration calibration accuracies which were specifically assumed in the PBAPS Unit 2 & 3 setpoint calculations. Plant calibration procedures will ensure the assumptions regarding calibration accuracy are maintained. The proposed Allowable Values and Trip Setpoints have been established from each design or safety analysis limit by accounting for instrument accuracy, calibration and drift uncertainties, as well as process measurement accuracy and primary element accuracy using the PECO Energy Instrument Setpoint Methodology or the GE Instrument Setpoint Methodology. The use of these methodologies for establishing Allowable Values and Trip Setpoints ensures design or safety analysis limits are not exceeded in the event of transients or accidents and accounts for uncertainties and environmental conditions.

ADMINISTRATIVE CHANGES

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications. In the specific case of the ECCS Instrumentation Section, and Limiting Safety System Setting Section that list ECCS Instrumentation setpoints, the Specifications have been combined into one Specification and the new Specification number is 3.3.5.1, titled Emergency Core Cooling System (ECCS) Instrumentation.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 Not used.

A_3 This change deletes the specific line items for performing the Logic System Functional Test for the Containment Cooling Subsystems from current Technical Specification Table 4.2.B. The proposed Technical Specifications groups specific Functions by ECCS System (e.g., the Containment Cooling Subsystems will be depicted as the specific functions which provide the isolation of the applicable valves in these subsystems, Function 2.e in Table 3.3.5.1-1). Since the test is retained for these items, this change constitutes an administrative change. In addition, the first sentence of Note 4 has been deleted since it is duplicative of the simulated automatic actuation test requirement in each of the current ECCS specifications. These changes are consistent with NUREG-1433.

ADMINISTRATIVE CHANGES (continued)

A_4 This proposed change deletes the note in the current Technical Specifications which allows specific instrumentation to be excepted from the functional test definition as it is adequately addressed by the proposed Channel Functional Test definitions. All changes to definitions in the current Technical Specification were justified in the Discussion of Changes to Chapter 1.0, "Use and Applications." Thus, any deviations from any test required by Table 3.3.5.1-1 will be specified in the individual surveillance procedures. This change is consistent with NUREG-1433.

A_5 The current Applicability for the ECCS Instrumentation is when the system(s) it initiates or controls are required to be Operable as specified in Section 3.5. The changes to the specific ECCS System Applicabilities were described in the Discussion of Changes for Section 3.5. This proposed change specifies by a footnote (footnote d)that the only time the HPCI Functions are required to be Operable in Modes 2 and 3 is with reactor steam dome pressure > 150 psig. This proposed change also specifies by a footnote (footnote e) that the only time the ADS Functions are required to be Operable in Modes 2 and 3 is with reactor steam dome pressure > 100 psig. Since the Applicability of the HPCI and ADS Instrumentation is consistent with the requirements of the HPCI System and ADS Specifications in Section 3.5, this is considered an administrative change. This change is consistent with NUREG-1433.

A_6 The Calibration specified in the Logic System Functional Test Table for the specific time delay relays will be deleted from the note. The proposed Technical Specifications will specify in Table 3.3.5.1-1 that Channel Calibrations are required for the specific time delay relays. This change is consistent with NUREG-1433.

A_7 This change proposes to add a Note which will allow separate Condition entry for each channel. This change provides more explicit instructions for proper application of the Actions for Technical Specifications compliance. In conjunction with the proposed Specification 1.3 - "Completion Times," the Note ("Separate Condition entry ...") and "in one or more Functions" provides more explicit direction of the current interpretation of the existing Specifications. This change is considered administrative and is consistent with NUREG-1433.

ADMINISTRATIVE CHANGES (continued)

A_8 This proposed change deletes the line item for the quarterly Channel Functional Test. The Channel Calibration encompasses the Channel Functional Test. Since the Channel Calibration is also required quarterly a separate line item for the Channel Functional Test is not required. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 The proposed change adds new Functions to the ECCS Instrumentation Table. Along with these added Functions are added Actions and Surveillance Requirements. The addition of new requirements constitute a more restrictive change. This change is consistent with NUREG-1433. Below is a list of the added Functions, and Surveillance Requirements and their associated frequency. The list is categorized by ECCS System.

Core Spray

1.d Core Spray Pump Discharge Flow—Low (Bypass):

SR 3.3.5.1.2 Channel Functional Test - 92 days
SR 3.3.5.1.4 Channel Calibration - 24 months

Low Pressure Coolant Injection

2.g Low Pressure Coolant Injection Pump Discharge Flow—Low (Bypass)

SR 3.3.5.1.2 Channel Functional Test - 92 days
SR 3.3.5.1.4 Channel Calibration - 24 months
SR 3.3.5.1.5 Logic System Functional Test - 24 months

High Pressure Coolant Injection

3.f High Pressure Coolant Injection Pump Discharge Flow—Low (Bypass)

SR 3.3.5.1.2 Channel Functional Test - 92 days
SR 3.3.5.1.4 Channel Calibration - 24 months
SR 3.3.5.1.5 Logic System Functional Test - 24 months

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 (cont'd) Automatic Depressurization System

4.d Reactor Vessel Water Level—Low Low Low (Level 1), (Permissive)

SR 3.3.5.1.1	Channel Check - 12 hours
SR 3.3.5.1.2	Channel Functional Test - 92 days
SR 3.3.5.1.4	Channel Calibration - 24 months
SR 3.3.5.1.5	Logic System Functional Test - 24 months

5.d Reactor Vessel Water Level—Low Low Low (Level 1), (Permissive)

SR 3.3.5.1.1	Channel Check - 12 hours
SR 3.3.5.1.2	Channel Functional Test - 92 days
SR 3.3.5.1.4	Channel Calibration - 24 months
SR 3.3.5.1.5	Logic System Functional Test - 24 months

M_2 This change increases the Surveillance Frequency for the Channel Check from daily to 12 hours. The Channel Check performed every 12 hours ensures that a gross failure of instrumentation has not occurred. Thus, performance of the Channel Check guarantees that undetected outright channel failure is limited to 12 hours. Increasing Surveillance Frequencies constitutes a more restrictive change. This change is consistent with NUREG-1433.

M_3 This change proposes to require 8 channels of RHR pump discharge pressure instruments. The current Specification from Table 3.2.B requires 2 channels per trip system and specifies that there are 4 channels by design. Increasing the number of channels required to 8 channels per trip system is consistent with the PBAPS design (8 RHR pump discharge pressure inputs per trip system - 2 per pump). This change increases the number of channels required which constitutes a more restrictive change.

TECHNICAL CHANGES - RELOCATIONS

R_1 The change will relocate items which are procedural in nature (e.g. conversions, specific instructions, etc.) to procedures. These items will be retained and will require a 10 CFR 50.59 review in order to be changed. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS (continued)

R_2 This change proposes to relocate the current "Trip Level Setting" column in current Technical Specifications Table 3.2.B and replace it with an "Allowable Value" column in the proposed Technical Specifications Table 3.3.5.1-1. Trip setpoints are an operational detail that is not directly related to the Operability of the instrumentation and will be relocated to a licensee controlled document. The Allowable Value is the required limitation for the parameter and this value will be inserted in the table. Any change to the trip setpoints will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_3 This change proposes to relocate specific information about the Functions (e.g., other Functions required to initiate the system, the role of the Function in initiating the system, etc.). This information will be relocated to the Bases of the proposed Technical Specifications. Any changes to this requirement will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_4 This change relocates the requirements for the Trip System bus power monitors, the core spray sparger differential pressure monitor, the LPCI Cross Connect Position Indication, and the Surveillance requirements for the ADS Relief Valves Bellows pressure switches to a licensee controlled document. These monitors do not necessarily relate directly to the respective system Operability. In general, the BWR Standard Technical Specifications support Operability of a system or component. Control of the availability of, and necessary compensatory activities if not available, for indications, monitoring instruments, and alarms are addressed by plant operational procedures and policies. Therefore, this instrumentation, along with the supporting surveillances and actions are relocated. Any changes to these requirements will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_5 This change proposes to relocate specifics about the instruments (what they consist of, etc.) to the procedures/bases. Any changes to these requirements will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS (continued)

R_6 This change proposes that the surveillance for the area cooling for safeguards systems (CTS Table 4.2.B, Item 8) be relocated to plant procedures. The requirement for testing the compartment coolers initiation was relocated to plant procedures. Details on testing some support systems have been relocated to licensee controlled documents. Relocating requirements for the compartment coolers does not preclude them from being maintained Operable. They are required to be Operable in order for the HPCI, RCIC, LPCI and CS systems to be Operable and as a result are adequately addressed by the definition of Operability. This change is consistent with NUREG-1433.

R_7 This instrument Function is being relocated to plant specific controls. This instrument has no impact on the LPCI System. The purpose of this instrument is to preclude inadvertent actuation of containment and suppression pool sprays during a LOCA. If a LOCA signal is present, the containment and suppression pool spray valves cannot be opened unless the reactor vessel water level is above the 2/3 core height level (to preclude diversion of LPCI when it is needed for core flooding) and the drywell pressure is $\geq$ 1.0 psig and $\leq$ 2.0 psig (indicative of a valid need for operating drywell and suppression pool sprays). If the instrument is inoperable such that it trips too soon or too late (or not at all), the LPCI System is not impacted.

If the instrument trips too soon, the reactor vessel water level 2/3 core height Function still ensures that flow is not diverted away from core flooding. In fact, the major contributor to potential flow diversion is suppression pool cooling, and its valves are only precluded from opening by the 2/3 core height instrument. The flow diverted by the drywell and suppression pool sprays is a small fraction of that diverted by suppression pool cooling. Thus, Operability of LPCI is not impacted. While tripping of the instrument allows one of the permissives for opening drywell and suppression pool spray valves to be met, inadvertent operation does not result, since manual actions must still be taken to open the valves if the other permissive (2/3 core height) is also met. In addition, if a LOCA signal is not present, this instrument does not preclude operation of the drywell and suppression pool spray valves. Therefore, inadvertent operation of drywell spray has been analyzed at PBAPS and does not result in containment failure due to operation

TECHNICAL CHANGES - RELOCATIONS

R_7 (cont'd

of the reactor building-to-suppression chamber and the suppression chamber-to-drywell vacuum breakers. These vacuum breakers are controlled by Technical Specifications (current and proposed). Therefore, Operability of the Suppression Pool Spray System is not impacted.

If the instrument trips too late or not at all, then no flow can be diverted by the drywell and suppression pool sprays; thus LPCI is not affected. The only Technical Specification system affected in this case is the Suppression Pool Spray System. A failure of the instrument to function would preclude the suppression pool spray valves from being opened from the control room. However, this system is a manually controlled system that is not needed for a minimum of 10 minutes following a DBA LOCA, and the valve could still be opened locally at the valve operator. In addition, the instrument could be overridden to allow operation from the control room. Therefore, failure of this instrument may not even result in the Suppression Pool Spray System being inoperable.

Since this instrument does not relate to LPCI Operability, and the Suppression Pool Spray System is a manually actuated system, this instrument Function is being relocated to plant specific controls. Any change to this instrument function will be controlled by the provisions of 10 CFR 50.59.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1

This change proposes to modify the Applicability for the LPCI Functions associated with the recirculation discharge valves by requiring them to be Operable in Modes 1, 2, and 3 with associated recirculation pump discharge valves open. This is reasonable since this Function is only required to be Operable when the recirculation valves are open which could hinder the coolant reaching the core. If the recirculation valves are closed then this Function is not required since its function is to close the recirculation valves. Also with the recirculation valve closed, the instruments function has been completed. Re-opening of the valve is a very controlled evolution, and could not be performed without strict administrative controls. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L_2 The Frequency for the Channel Calibration of the HPCI suction source transfer instrumentation (Condensate Storage Tank Level—Low and Suppression Pool Water Level—High) has been changed from 3 months to 24 months. These instruments are mechanical float type switches. Due to the construction and principles of operation of float type switches, the typical failure mode is to not operate. As a result, this type of failure would be detected during the quarterly Channel Functional Test. Therefore, extending the surveillance is considered acceptable and is consistent with other similar Surveillances.

L_{av} This change revises the Technical Specification setpoints for proposed Section 3.3 instrumentation to reflect Allowable Values consistent with the philosophy of NUREG-1433. These Allowable Values (to be included in Technical Specifications) and the Trip Setpoints (to be included in plant procedures) have been established consistent with the PECO Energy Instrument Setpoint Methodology of the General Electric (GE) Instrument Setpoint Methodology; the PBAPS Units 2 & 3 specific safety analysis limits as modified by NEDC-32183P, "Power Rerate Safety Analysis Report for Peach Bottom 2 & 3," dated May 1993; and the uncertainties associated with the PBAPS Units 2 & 3 instrumentation. The setpoint evaluation used actual PBAPS physical data and operating practices to ensure the validity of the resulting Allowable Values and Trip Setpoints. Changes resulting from the Power Rerate analyses and the effect on safety analysis limits were previously evaluated in the licensee amendment requests (93-12) for Power Rerate (letter dated June 23, 1993, from G.A. Hunger (PECo) to NRC). All changes to safety analysis limits, applied in the methodologies, were evaluated and confirmed as ensuring safety analysis licensing acceptance limits are maintained. All design limits, applied in the methodologies, were confirmed as ensuring that applicable design requirements of the associated systems are maintained. The methodologies used to derive the Allowable Values and Trip Setpoints are based on combining the uncertainties of the associated channels as documented in letter dated May 2, 1994 from G.A. Hunger (PECO Energy) to NRC responding to the Request for Additional Information Regarding Power Rerate Request dated March 29, 1994 (RAI-2). The methodologies used in the evaluation are consistent with the methodology used for Limerick Units 1 & 2 and documented in NEDC-31336, "General Electric Instrumentation Setpoint Methodology." The NRC approval of NEDC-31336 is documented in a Safety Evaluation Report transmitted

TECHNICAL CHANGES - LESS RESTRICTIVE

L_{av} (cont'd) by letter from B. Boger (NRC) to D. Roare (GE) dated February 9, 1993. In the methodologies, the Trip Setpoints take into consideration calibration accuracies which were specifically assumed in the PBAPS Unit 2 & 3 setpoint calculations. Plant calibration procedures will ensure the assumptions regarding calibration accuracy are maintained. The proposed Allowable Values and Trip Setpoints have been established from each design or safety analysis limit by accounting for instrument accuracy, calibration and drift uncertainties, as well as process measurement accuracy and primary element accuracy using the PECO Energy Instrument Setpoint Methodology or the GE Instrument Setpoint Methodology. The use of these methodologies for establishing Allowable Values and Trip Setpoints ensures design or safety analysis limits are not exceeded in the event of transients or accidents and accounts for uncertainties and environmental conditions.

DISCUSSION OF CHANGES
ITS 3.3.5.2: REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM INSTRUMENTATION

ADMINISTRATIVE CHANGES

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

In the specific case of the RCIC Instrumentation and Limiting Safety System Setting Sections that list RCIC System instrumentation setpoints, the Specifications have been combined into one Specification and the new Specification number is 3.3.5.2, RCIC System Instrumentation.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 This change proposes to add a Note which will allow separate Condition entry for each channel. This change provides more explicit instructions for proper application of the Actions for Technical Specifications compliance. In conjunction with the proposed Specification 1.3 - "Completion Times," the Note ("Separate Condition entry ...") and "in one or more Functions" provides more explicit direction of the current interpretation of the existing Specifications. This change is considered administrative and is consistent with NUREG-1433.

A_3 The current Applicability for the RCIC Instrumentation is when the system(s) it initiates or controls are required to be Operable as specified in CTS Section 3.5. This proposed change adds the specific Applicability in ITS Section 3.5.3. The specific differences between the Applicabilities in the CTS and ITS are described in the Discussion of Changes for Section 3.5. Based on this fact, the proposed change is administrative. This change is consistent with NUREG-1433.

ADMINISTRATIVE CHANGES (continued)

A_4 This proposed change deletes the note in the current Technical Specifications which allows specific instrumentation to be excluded from the functional test definition. All changes to definitions in the current Technical Specification were justified in the Discussion of Changes to Chapter 1.0, "Use and Applications." Thus, any deviations from any test required by Table 3.3.5.2-1 will be specified in the individual surveillance procedures. In addition, the first sentence of Note 4 has been deleted since it is duplicative of the simulated automatic actuation test requirement in the current RCIC System specification. These changes are consistent with NUREG-1433.

A_5 This change proposes to delete the note requiring the logic system functional tests to include a calibration of time delay relays and timers necessary for proper functioning of the trip system. This note is not applicable to RCIC since RCIC does not have any timers or time delay relays. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 This change increases the Surveillance Frequency for the Channel Check from daily to 12 hours. The Channel Check performed every 12 hours ensures that a gross failure of instrumentation has not occurred. Thus, performance of the Channel Check guarantees that undetected outright channel failure is limited to 12 hours. Increasing Surveillance Frequencies constitutes a more restrictive change. This change is consistent with NUREG-1433.

M_2 This proposed change adds a requirement to perform a Logic System Functional Test of the RCIC System. The current requirement only applies to the RCIC System Auto Isolation Function. Since this change adds a new requirement, it is classified as a more restrictive change. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS

R_1 The change will relocate items which are procedural in nature (e.g., conversions, specific instructions, etc.) to procedures. These items will be retained and will require a 10 CFR 50.59 review in order to be changed. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS (continued)

R_2 This change proposes to relocate the current "Trip Level Setting" column in current Technical Specifications Table 3.2.B and replace it with an "Allowable Value" column in the proposed Technical Specifications Table 3.3.5.2-1. Trip setpoints are an operational detail that is not directly related to the Operability of the instrumentation and will be relocated to a licensee controlled document. The Allowable Value is the required limitation for the parameter and this value will be inserted in the table. Any change to the trip setpoints will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_3 This change proposes to relocate specifics about the instruments (what they consist of, etc.) to the procedures/Bases. Any changes to these requirements will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_4 This change relocates the requirements for the Trip System bus power monitor to a licensee controlled document. This monitor does not necessarily relate directly to the respective system Operability. In general, the BWR Standard Technical Specifications support Operability of a system or component. Control of the availability of, and necessary compensatory activities if not available, for indications, monitoring instruments, and alarms are addressed by plant operational procedures and policies. Therefore, this instrumentation, along with the supporting surveillances and actions are relocated. Any changes to these requirements will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_{av} This change revises the Technical Specification setpoints for proposed Section 3.3 instrumentation to reflect Allowable Values consistent with the philosophy of NUREG-1433. These Allowable Values (to be included in Technical Specifications) and the Trip Setpoints (to be included in plant procedures) have been established consistent with the PECO Energy Instrument Setpoint Methodology of the General Electric (GE) Instrument Setpoint Methodology; the PBAPS Units 2 & 3 specific safety analysis limits as modified by NEDC-32183P, "Power Rerate Safety Analysis Report for Peach Bottom 2 & 3," dated May 1993; and the uncertainties associated with the PBAPS Units 2 & 3 instrumentation. The setpoint evaluation used actual PBAPS physical data and operating practices to ensure the validity of the resulting Allowable Values and Trip Setpoints. Changes

TECHNICAL CHANGES - LESS RESTRICTIVE

L_{ev} (cont'd) resulting from the Power Rerate analyses and the effect on safety analysis limits were previously evaluated in the licensee amendment requests (93-12) for Power Rerate (letter dated June 23, 1993, from G.A. Hunger (PECo) to NRC). All changes to safety analysis limits, applied in the methodologies, were evaluated and confirmed as ensuring safety analysis licensing acceptance limits are maintained. All design limits, applied in the methodologies, were confirmed as ensuring that applicable design requirements of the associated systems are maintained. The methodologies used to derive the Allowable Values and Trip Setpoints are based on combining the uncertainties of the associated channels as documented in letter dated May 2, 1994 from G.A. Hunger (PECO Energy) to NRC responding to the Request for Additional Information Regarding Power Rerate Request dated March 29, 1994 (RAI-2). The methodologies used in the evaluation are consistent with the methodology used for Limerick Units 1 & 2 and documented in NEDC-31336, "General Electric Instrumentation Setpoint Methodology." The NRC approval of NEDC-31336 is documented in a Safety Evaluation Report transmitted by letter from B. Boger (NRC) to D. Roare (GE) dated February 9, 1993. In the methodologies, the Trip Setpoints take into consideration calibration accuracies which were specifically assumed in the PBAPS Unit 2 & 3 setpoint calculations. Plant calibration procedures will ensure the assumptions regarding calibration accuracy are maintained. The proposed Allowable Values and Trip Setpoints have been established from each design or safety analysis limit by accounting for instrument accuracy, calibration and drift uncertainties, as well as process measurement accuracy and primary element accuracy using the PECO Energy Instrument Setpoint Methodology or the GE Instrument Setpoint Methodology. The use of these methodologies for establishing Allowable Values and Trip Setpoints ensures design or safety analysis limits are not exceeded in the event of transients or accidents and accounts for uncertainties and environmental conditions.

Primary Containment Isolation Instrumentation (A.)

TABLE ~~3.2.B~~ 3.3.6.1 ~~(continued)~~ UNIT 2

~~INSTRUMENTATION THE INITIATES OR CONTROLS~~
~~THE CORE AND CONTAINMENT COOLING SYSTEMS~~

(A4) Minimum No. of Operable Inst. Channels per Trip System ~~(ACTION)~~ (A.)	(A.) Function ~~Trip~~ Function	Allowable Value (Lav) ~~Trip Level Setting~~ (A5)	Number of Instrument Channels Provided by Design	(A1) Conditions Referenced from Required Action C.1 ~~Remarks~~ (A.)
(2) 4 (5) (13) (15)	3.c HPCI Steam Line Low Pressure	100 p 50 psig ~~(3)~~ (R4) (R3)	4 Inst.	F
(A3) (8) 2 (13) (15)	3.e HPCI Turbine Compartment Temperature	≤200 deg. F ~~(3)~~ (R3)	4 Inst.	F
4 (13) (15)	3.e HPCI Steam Line Area Temperature	≤200 deg. F ~~(3)~~ (R3)	8 Inst. 16 Inst.	F (A1)
2 (13) (15) Action F (A1)	3.e HPCI/RHR Valve Station Area Temperature	≤200 deg. F (3) (R3) Lav	4 Inst. (R2)	F
1 (1)	LPCI Cross-Connect Position	NA	1 Inst.	Initiates annunciation when valve is not closed.
1 per 4 kV bus (1)	4 kV Emergency Bus Undervoltage Relay (HGA)	25% (±5%) of Rated Voltage		1. Trips all loaded breakers. 2. Fast transfer permissive. 3. Dead bus start of diesel.
1 per 4 kV bus (1)	4 kV Emergency Bus Sequential Loading Relay (SV)	95% (+0%, -10%) of Rated Voltage		Permits sequential starting of vital loads.

See Discussion of Changes ITS 3.3.8.1, LOP Instrumentation

See Discussion of Changes ITS 3.8.1, AC Sources - Operating

See Discussion of Changes ITS 3.3.5.1, ECCS Instrumentation

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Primary Containment Isolation Instrumentation

TABLE ~~3.2.B~~ 3.3.6.1 ~~(continued)~~ A1

~~INSTRUMENTATION THE INITIATES OR CONTROLS THE CORE AND CONTAINMENT COOLING SYSTEMS~~

UNIT 3

Function K1

Minimum No. of Operable Inst. Channels per Trip System (ACTION)	Trip Function A1	Allowable Value L4 ~~Trip Level Setting~~ A5	~~Number of Instrument Channels Provided by Design~~	Conditions Reference from Required Action C.1 ~~Remarks~~ A1
A4 2 ~~4 (5)~~ (13) (15) 3.c	HPCI Steam Line Low Pressure	100 ~~p~~ ~~50~~ psig ~~(3)~~ R3 R4	~~4 inst.~~	F
A2 8 2 (13) (15) 3.e	HPCI Turbine Compartment Temperature	≤200 deg. F ~~(3)~~ R3	~~4 Inst.~~	F
4 (13) (15) 3.e	HPCI Steam Line Area Temperature	≤200 deg. F ~~(3)~~ R3	~~8 Inst.~~ ~~16 Inst.~~	F
2 (13) (15) 3.e Action F A1	HPCI/RHR Valve Station Area Temperature	≤200 deg. F ~~(3)~~ R3 L4	~~4 Inst.~~ R2	F A1
1 (1)	LPCI Cross-Connect Position	NA	1 Inst.	Initiates annunciation when valve is not closed.
1 per 4 kV bus (1)	4 kV Emergency Bus Undervoltage Relay (HGA)	25% (±5%) of Rated Voltage		1. Trips all loaded breakers. 2. Fast transfer permissive. 3. Dead bus start of diesel.
1 per 4 kV bus (1)	4 kV Emergency Bus Sequential Loading Relay (SV)	95% (+0%, -10%) of Rated Voltage		Permits sequential starting of vital loads.

See Discussion of Changes ITS 3.3.8.1, LOP Instrumentation

See Discussion of Changes ITS 3.8.1, AC Sources - Operating

See Discussion of Changes ITS 3.3.5.1, ECCS Instrumentation

DISCUSSION OF CHANGES
ITS 3.3.6.1: PRIMARY CONTAINMENT ISOLATION INSTRUMENTATION

ADMINISTRATIVE CHANGES

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications. In the specific case of the Primary Containment Isolation (PCI) Instrumentation Section, ECCS Instrumentation Section, and the Limiting Safety System Setting Section that list PCI instrumentation setpoints, the Specifications have been combined into one Specification and the new Specification is 3.3.6.1, titled Primary Containment Isolation Instrumentation.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 The steam line temperature monitoring system for Main Steam, HPCI, and RCIC each consist of 16 temperature detectors monitoring 4 locations with one detector from each of the areas monitored contributing to one of four trip strings. Any of the 4 channels in a trip string is capable of tripping the trip string. The trip strings are arranged in a one-out-of-two-twice logic. Therefore, proposed Table 3.3.6.1-1 Functions 1.e (Main Steam), 3.e (HPCI), and 4.e (RCIC) are presented as having 2 trip systems with 8 channels required per trip system. This change creates consistency between Main Steam, HPCI and RCIC and is consistent with BWR Standard Technical Specifications, NUREG-1433.

A_3 This change proposes to add a Note which will allow separate Condition entry for each channel. This change provides more explicit instructions for proper application of the Actions for Technical Specifications compliance. In conjunction with proposed Specification 1.3 - "Completion Times," the Note ("Separate Condition entry is allowed for each channel.") provides more explicit direction of the interpretation of the existing Specifications. This change is considered administrative and is consistent with BWR Standard Technical Specifications, NUREG-1433.

ADMINISTRATIVE CHANGES (continued)

A_4 Existing Table 3.2.B, under "Minimum Number of Operable Channels per Trip System," requires that the HPCI Steam Line Low Pressure Function have 4 Operable channels per trip system. Table 3.2.B Note (5) states that HPCI has only one trip system for this function. UFSAR 7.3.4.8 and associated drawings indicated that low pressure in the HPCI turbine steam line is sensed by four pressure switches which are arranged as two trip systems, both of which must trip to initiate isolation of the HPCI turbine steam line. Each trip system receives inputs from two pressure switches, either one of which can initiate isolation. Proposed Specification 3.3.6.1, Table 3.3.6.1-1, Function 3.c, reflects the design as described in the UFSAR and associated plant drawings. Since the total number of channels required remains at 4, the change is considered administrative in nature.

A_5 Existing Table 3.2.D, Notes 1 and 3, identify the Applicability for Function 2.c, Main Stack Monitor Radiation—High, in proposed Table 3.3.6.1-1. Currently, this Function must be Operable "only when the containment is purging through the SGTS and containment integrity is required." Proposed Specification 3.3.6.1 will require that this Function be Operable in Modes 1, 2, and 3. This is an administrative change because Primary containment is required in Modes 1, 2, and 3. Additionally, isolation of the affected penetrations satisfies the Required Action for this Function which would permit the Main Stack Monitor Radiation—High Function to be inoperable in Modes 1, 2, and 3 except when the containment is being purged.

A_6 This proposed change deletes the line item for the quarterly Channel Functional Test. The Channel Calibration encompasses the Channel Functional Test. Since the Channel Calibration is also required quarterly, a separate line item for the Channel Functional Test is not required.

A_7 This proposed change deletes Note 3 in the current Technical Specifications which allows specific instrumentation to be excepted from the functional test definition as it is adequately addressed by the proposed Channel Functional Test definition. All changes to definitions in the current Technical Specifications were justified in the Discussion of Changes to Chapter 1.0, "Use and Applications." Thus, any deviations from any test required by Table 3.3.6.1-1 will be specified in the individual surveillance procedures. The first sentence of current Note 4 has been deleted since it is duplicative of the simulated automatic actuation test requirement in the current

ADMINISTRATIVE CHANGES

A_7 (cont'd) primary containment isolation valves specification. The calibration specified in current Note 6 for the time delay relays and timers has been deleted. The proposed Technical Specifications will specify in Table 3.3.6.1-1 that Channel Calibrations are required for the specific time delay relays. These changes are consistent with NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 The proposed change adds new Functions to the Primary Containment Isolation Instrumentation Table. Along with these additional Functions are the associated Conditions, Required Actions and Surveillance Requirements. The addition of new requirements constitute a more restrictive change. This change is consistent with NUREG-1433. Below is a list of the added Functions, and Surveillance Requirements and associated frequency. The list is categorized by ITS Containment Isolation Group.

High Pressure Coolant Injection (HPCI) Isolation

3.d Drywell Pressure—High

SR 3.3.6.1.1	Channel Check - 12 hours
SR 3.3.6.1.2	Channel Functional Test - 92 days
SR 3.3.6.1.5	Channel Calibration - 24 months
SR 3.3.6.1.7	Logic System Functional Test - 24 months

Reactor Core Isolation Cooling (RCIC) Isolation

4.d Drywell Pressure—High

SR 3.3.6.1.1	Channel Check - 12 hours
SR 3.3.6.1.2	Channel Functional Test - 92 days
SR 3.3.6.1.5	Channel Calibration - 24 months
SR 3.3.6.1.7	Logic System Functional Test - 24 months

Reactor Water Cleanup (RWCU) System Isolation

5.b SLC System Initiation

SR 3.3.6.1.7 Logic System Functional Test - 24 months

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 (cont'd)

5.c Reactor Water Level—Low

SR 3.3.6.1.1	Channel Check - 12 hours
SR 3.3.6.1.2	Channel Functional Test - 92 days
SR 3.3.6.1.5	Channel Calibration - 24 months
SR 3.3.6.1.7	Logic System Functional Test - 24 months

Shutdown Cooling System Isolation

6.b Reactor Water Level—Low

SR 3.3.6.1.1	Channel Check - 12 hours
SR 3.3.6.1.2	Channel Functional Test - 92 days
SR 3.3.6.1.5	Channel Calibration - 24 months
SR 3.3.6.1.7	Logic System Functional Test - 24 months

M_2 Proposed Specification 3.3.6.1 will increase the Frequency of the Channel Checks currently specified in Tables 4.2.A, 4.2.B, and 4.2.D from once per day to once per 12 hours and for Table 4.2.B Item 12, adds a Channel Check requirement once per 12 hours (currently none is required). This change adds additional requirements and it constitutes a more restrictive change. This change is consistent with the BWR Standard Technical Specifications, NUREG-1433.

M_3 Proposed Specification 3.3.6.1 will include more restrictive Required Action if the Refuel Area Ventilation Exhaust Radiation—High (proposed Function 2.e) or the Reactor Building Ventilation Exhaust Radiation—High (proposed Function 2.d) have fewer than the minimum required number of Operable channels and the channels are not placed in trip within 24 hours. Currently, Specification 3.2.D (Table 3.2.D) requires only that operation of refueling equipment cease, secondary containment be isolated and SGT started. Under identical conditions, proposed Specification 3.3.6.1 (Condition H) will require that the reactor be in Mode 3 within 12 hours and Mode 4 within 36 hours. Since this change requires placing the reactor outside of the applicable Modes for these instruments, the proposed change is more restrictive. This change is consistent with the BWR Standard Technical Specifications, NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

M_4 Currently, Surveillance Requirements for the PCI Functions associated with high drywell pressure, reactor low water level, and MSL high radiation are specified in Table 4.1.2 (Table 4.2.B, Note 5) with the SRs for the Reactor Protection System. Table 4.1.2 requires Channel Calibrations (Proposed SR 3.3.6.1.3 and SR 3.3.6.1.5). Proposed Specification 3.3.6.1 will add new requirements for Channel Functional Tests (Proposed SR 3.3.6.1.2 for Functions 2.a and 2.b) and Logic System Functional Tests (Proposed SR 3.3.6.1.7 for Functions 1.d, 2.a, 2.b, and 7.a). This change is consistent with the BWR Standard Technical Specifications, NUREG-1433. This additional requirement will affect the following PCI Functions:

Main Steam Line Isolation

1.d Main Steam Line High Radiation

SR 3.3.6.1.1 Channel Check - 12 hours
SR 3.3.6.1.7 Logic System Functional Test - 24 months

Primary Containment Isolation

2.a Reactor Vessel Water Level--Low

SR 3.3.6.1.1 Channel Check - 12 hours
SR 3.3.6.1.2 Channel Functional Test - 92 days
SR 3.3.6.1.7 Logic System Functional Test - 24 months

2.b Drywell Pressure—High

SR 3.3.6.1.1 Channel Check - 12 hours
SR 3.3.6.1.2 Channel Functional Test - 92 days
SR 3.3.6.1.7 Logic System Functional Test - 24 months

Feedwater Recirculation Isolation

7.a Reactor Pressure—High

SR 3.3.6.1.7 Logic System Functional Test - 24 months

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

M_5 Existing Table 3.2.A (Item 6 and associated Note 2.B) requires that the Main Steam Line be isolated within 12 hours of the determination that there are fewer than the minimum required number of Operable or tripped channels. Under the identical conditions, proposed Specification 3.3.6.1-1 (Table 3.3.6.1-1, Function 1.b, Condition E) will require that the reactor be in Mode 2 within 6 hours. This change is acceptable because it places the reactor outside the Mode of Applicability in less time than the current Specification. This change is consistent with the BWR Standard Technical Specifications, NUREG-1433.

M_6 The proposed change adds new Surveillance Requirement Functions to the Primary Containment Isolation Instrumentation Table. The addition of new requirements constitute a more restrictive change. This change is consistent with NUREG-1433. Below is a list of the added Surveillance Requirements and associated Frequency. The list is categorized by ITS Containment Isolation Group.

Primary Containment Isolation

2.c SR 3.3.6.1.7, Logic System Functional Test - 24 months
2.d SR 3.3.6.1.7, Logic System Functional Test - 24 months
2.e SR 3.3.6.1.7, Logic System Functional Test - 24 months

TECHNICAL CHANGES - RELOCATIONS

R_1 Existing Specification 3.2.A, Table 3.2.A, Item 2, Reactor High Pressure (Shutdown Cooling Isolation), isolates the Shutdown Cooling System whenever reactor pressure exceeds 75 psig. This trip has a reset function that is controlled by Specification 3.2.B, Table 3.2.B, Reactor Low Pressure. This reset function provides a permissive for inclusion of the LPCI injection valves in the Shutdown Cooling System Isolation if reactor pressure is below the reset setpoint and the shutdown cooling suction valves are open. Specification 3.2.B, Table 3.2.B, Reactor Low Pressure, will be relocated to plant procedures because the permissive from the reset of Reactor High Pressure (Shutdown Cooling Isolation) does not serve a safety function. Inclusion of the LPCI injection valves in the Shutdown Cooling System Isolation requires the shutdown cooling suction valves to be open in addition to the reset of the reactor pressure trip. However, opening the shutdown cooling suction valves also requires the reset of the reactor pressure trip. Failure of the reactor pressure trip to reset will prevent the opening of the

TECHNICAL CHANGES - RELOCATIONS

R_1 (cont'd) shutdown cooling suction valves and eliminate the need for the Shutdown Cooling Isolation Function. Therefore, Specification 3.2.B, Table 3.2.B, Reactor Low Pressure, will be relocated to plant procedures. Any changes to this requirement will require a 10 CFR 50.59 review. Relocation of this requirement is consistent with NUREG-1433.

R_2 This change proposes to relocate the number of instrument channels provided by design column for each Function. This information will be relocated to the Bases of the proposed Technical Specifications. Any changes to this requirement will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_3 The specific details relating to the design, plant operations, performance of surveillance and maintenance of the PCI Instrumentation are being relocated to the plant controlled procedures. Placing these details in the plant procedures provides assurance they will be maintained. Changes to the plant procedures are controlled so that the information will not be changed without a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_4 Currently, setpoints for HPCI and RCIC isolation on the steam line low pressure function (Table 3.2.B) is specified as "100>p>50 psig." This specification of both the trip and trip reset pressure provides some assurance of the availability of HPCI and RCIC following a trip on steam line low pressure. Specification 3.3.6.1 (Functions 3.c and 4.c) will specify the steam line low pressure trip setpoint. However, the trip reset will be relocated to plant procedures because the trip reset is not assumed in any accident analysis. Placing this requirement in the plant procedures provides assurance it will be maintained. Changes to the plant procedures are controlled so that the information will not be changed without a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_5 This change proposes to relocate the current "Trip Level Setting" column in current Technical Specifications Tables 3.2.A, 3.2.B and 3.2.D and replace it with an "Allowable Value" column in the proposed Technical Specifications Table 3.3.6.1-1. Trip setpoints are an operational detail that is not directly related to the Operability of the instrumentation and will be relocated to a licensee controlled document. The Allowable Value is the required limitation for the parameter and this value will be inserted in the table. Any change to the trip setpoints will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS (continued)

R_6 Existing Specification 3.2.A (Table 3.2.A, Note 9) contains compensatory actions associated with recovery of a loss of ventilation in the MSL tunnel. These compensatory actions are not needed to satisfy Required Actions for a complete loss of isolation function specified in NUREG-1433 but represent good engineering practice. Therefore, the compensatory actions associated with recovery of a loss of ventilation in the MSL tunnel currently in existing Specification 3.2.A (Table 3.2.A, Note 9) are being relocated to the Bases.

R_7 System operational details (when not to plant in trip) have been relocated to the Bases and procedures. These details are unnecessary in the LCO and can be adequately controlled in the Bases and procedures. Changes to the Bases will be controlled by the provisions of the Bases Control Process in Chapter 5 of the Technical Specifications. Changes to procedures will be controlled by the provisions of 10 CFR 50.59.

R_8 Existing Specification 3.2.A, Table 3.2.A, Item 11, Reactor Cleanup System High Temperature isolates the Reactor Water Cleanup (RWCU) System non-regenerative heat exchanger to protect the ion exchanger resin from damage due to high temperatures. Credit for this instrument is not assumed in any transient or accident analysis in the UFSAR, since this isolation is for ion exchanger resin protection only. As a result, the existing Technical Specification requirements for this function (including actions and surveillances) will be relocated to plant procedures. Any changes to these requirements will require a 10 CFR 50.59 review. Therefore, placing these requirements in plant procedures provides assurance they will be adequately maintained.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 Existing Specification 3.2.A (Table 3.2.A, Items 3, 5, 7, 8, and 9 and associated Notes 2.A and 2.B, as applicable) requires an orderly load reduction to be initiated and the reactor to be in Cold Shutdown in 24 hours if a required channel of Item 3 (MSL Isolation of Reactor Low Low Low Water Level) is inoperable and not placed in trip within the required time and the main steam lines be isolated in 12 hours if a required channel of Item 5, 7, 8, or 9 (MSL Isolation on Main Steam Tunnel High Radiation, Main Steam Line High Flow, or Main Steam Tunnel High Temperature)is inoperable and not placed in trip within the required time period. Under the identical

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 (cont'd) conditions, proposed Specification 3.3.6.1 (Table 3.3.6.1-1, Condition D) will allow the option of isolating the affected MSL in 12 hours or placing the reactor in Mode 3 within 12 hours and Mode 4 within 36 hours. This change is acceptable because placing the unit in Mode 3 within 12 hours and Mode 4 within 36 hours places the unit in a condition that is outside the Applicability for the function. This change is consistent with the BWR Standard Technical Specifications, NUREG-1433.

L_2 Existing Table 3.2.A (Items 1 and 4 and associated Note 2.A.) requires that the Reactor be in Cold Shutdown within 24 hours of the determination that there are fewer than the minimum required number of Operable or tripped channels of Reactor Low Level (Proposed Function 2.a) or High Drywell Pressure (Proposed Function 2.b). Under the identical conditions, proposed Specification 3.3.6.1 (Table 3.3.6.1-1, Functions 2.a and 2.b and associated Condition G) will require that the reactor be in Mode 3 within 12 hours and Mode 4 within 36 hours. The change in Completion Time from Cold Shutdown within 24 hours to Mode 3 within 12 hours and Mode 4 within 36 hours will require that the plant be shutdown (Mode 3) sooner than the existing specifications but it increases the amount of time before the reactor is outside the Mode of Applicability. This change is acceptable because the plant will be shutdown sooner but also allows for a more controlled cooldown which reduces thermal stress on components and also reduces the chances for a plant transient which could challenge safety systems. Additionally, this change makes the Completion Times associated with inoperable PCI Instrumentation consistent with the Completion Times associated with an inoperable PCI valve in proposed Specification 3.6.1.3. This change is consistent with the BWR Standard Technical Specifications, NUREG-1433.

L_3 Existing Specification 3.2.A (Table 3.2.A, Note 9) allows the setpoint of the MSL tunnel exhaust duct temperature function to be increased from the setpoint of approximately 200 degrees F to 250 degrees F for a period of 30 minutes to avoid a MSL isolation transient during a temporary loss of ventilation in the MSL tunnel. Proposed Specification 3.3.6.1 will not include this specific allowance; however, proposed Specification 3.3.6.1 will permit avoiding an MSL isolation during a temporary loss of MSL tunnel ventilation by deliberately entering into proposed Condition B and then raising the setpoints for the Main Steam Tunnel Temperature—High Function to 250 degrees F causing all channels of Main Steam Tunnel Temperature—High Function to be inoperable.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_3 (cont'd) Use of entry in Condition B will allow Main Steam Tunnel Temperature—High setpoints to remain above the required setpoint for 1 hour instead of the 30 minutes allowed by existing Specification 3.2.A (Table 3.2.A, Note 9). This change is acceptable for the same reasons that proposed Specification 3.3.6.1 Conditions B and D are acceptable Required Actions for a complete loss of the function MSL Tunnel Temperature—High. Specifically, the period time that the setpoint will be above the allowance value is short and during this short period of time MSL isolation capability as protection against a MSL break is maintained by redundant functions including MSL Flow—High, MSL Pressure—Low, and Reactor Water Level—Low. Additionally, increasing the setpoint for the MSL tunnel exhaust duct high temperature from approximately 200 degrees F to 250 degrees F will not disable the MSL isolation on high tunnel temperature although it will increase the size and/or duration of the leak required to initiate the isolation. Finally, allowing this extended time will potentially avoid a plant transient caused by a plant shutdown and does not represent a significant decrease in safety. The compensatory actions associated with the loss of Main Steam Tunnel Temperature—High function currently located in Note 9 to Table 3.2.A are being relocated to the Bases.

L_4 The Frequency for the Safeguards Area High Temperature (HPCI and RCIC Compartments) Channel Calibration is being decreased from 3 months to 24 months. PBAPS operating history has shown this instrument to be continually reliable over a 24 month period. In addition, these instruments are the same type as the HPCI and RCIC Steam Line High Temperature instruments, which already have a 24 month Frequency for the Channel Calibration. Therefore, it is acceptable to decrease the Frequency of this Surveillance. This change is also essentially consistent with NUREG-1433, which requires the SR to be performed on a refueling outage basis.

L_{av} This change revises the Technical Specification setpoints for proposed Section 3.3 instrumentation to reflect Allowable Values consistent with the philosophy of NUREG-1433. These Allowable Values (to be included in Technical Specifications) and the Trip Setpoints (to be included in plant procedures) have been established consistent with the PECO Energy Instrument Setpoint Methodology of the General Electric (GE) Instrument Setpoint Methodology; the PBAPS Units 2 & 3 specific safety analysis limits as modified by NEDC-32183P, "Power Rerate Safety Analysis Report for Peach Bottom 2 & 3," dated May 1993; and the uncertainties associated with the

TECHNICAL CHANGES - LESS RESTRICTIVE

L_{8V} (cont'd)

PBAPS Units 2 & 3 instrumentation. The setpoint evaluation used actual PBAPS physical data and operating practices to ensure the validity of the resulting Allowable Values and Trip Setpoints. Changes resulting from the Power Rerate analyses and the effect on safety analysis limits were previously evaluated in the licensee amendment requests (93-12) for Power Rerate (letter dated June 23, 1993, from G.A. Hunger (PECo) to NRC). All changes to safety analysis limits, applied in the methodologies, were evaluated and confirmed as ensuring safety analysis licensing acceptance limits are maintained. All design limits, applied in the methodologies, were confirmed as ensuring that applicable design requirements of the associated systems are maintained. The methodologies used to derive the Allowable Values and Trip Setpoints are based on combining the uncertainties of the associated channels as documented in letter dated May 2, 1994 from G.A. Hunger (PECO Energy) to NRC responding to the Request for Additional Information Regarding Power Rerate Request dated March 29, 1994 (RAI-2). The methodologies used in the evaluation are consistent with the methodology used for Limerick Units 1 & 2 and documented in NEDC-31336, "General Electric Instrumentation Setpoint Methodology." The NRC approval of NEDC-31336 is documented in a Safety Evaluation Report transmitted by letter from B. Boger (NRC) to D. Roare (GE) dated February 9, 1993. In the methodologies, the Trip Setpoints take into consideration calibration accuracies which were specifically assumed in the PBAPS Unit 2 & 3 setpoint calculations. Plant calibration procedures will ensure the assumptions regarding calibration accuracy are maintained. The proposed Allowable Values and Trip Setpoints have been established from each design or safety analysis limit by accounting for instrument accuracy, calibration and drift uncertainties, as well as process measurement accuracy and primary element accuracy using the PECO Energy Instrument Setpoint Methodology or the GE Instrument Setpoint Methodology. The use of these methodologies for establishing Allowable Values and Trip Setpoints ensures design or safety analysis limits are not exceeded in the event of transients or accidents and accounts for uncertainties and environmental conditions.

DISCUSSION OF CHANGES
ITS 3.3.6.2: SECONDARY CONTAINMENT ISOLATION INSTRUMENTATION

ADMINISTRATIVE CHANGES

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 This change will replace the current "Minimum No. of Operable Instrument Channels" and "No. of Instrument Channels Provided by Design," columns with a "Required Channels Per Trip System" column. This specifies the number of channels required to be Operable to get the actuation when required. This number includes provisions for the single failure criterion. This change is consistent with NUREG-1433.

A_3 This change will delete the requirement that Channel Functional Tests, Channel Calibrations, and Channel Checks are not required when the instruments are not required to be operable or are tripped. If a channel is outside of its Mode of Applicability or inoperable then there is no reason the test needs to be performed. The tests will, however, be performed on the channel prior to entering the Mode of Applicability or declaring the channel Operable. This is consistent with ITS Section 3.0. If a channel is tripped, testing does not need to be performed because the channel has performed its function. This change is consistent with NUREG-1433.

A_4 This change deletes the logic system functional test note which specifies that a calibration of time delay relays and timers necessary for proper functioning of the trip systems will be performed with the logic system functional test. This note is not applicable to PBAPS since there are no timers or delay relays associated with the Secondary Containment Isolation Instrumentation. This change is consistent with NUREG-1433.

ADMINISTRATIVE CHANGES (continued)

A_5 This change proposes to add a Note which will allow separate Condition entry for each channel. This change provides more explicit instructions for proper application of the Actions for Technical Specifications compliance. In conjunction with the proposed Specification 1.3 - "Completion Times," the Note ("Separate Condition entry ...") and "in one or more Functions" provides more explicit direction of the current interpretation of the existing Specifications. This change is considered administrative and is consistent with NUREG-1433.

A_6 The current Applicability for the Secondary Containment Isolation Radiation Monitoring Instrumentation is whenever the system(s) are required to be Operable (i.e., when Secondary Containment is required to be Operable). This proposed Applicability specifies the instrumentation to be Operable in Modes 1, 2, and 3, and during Core Alterations, operation with a potential for draining the reactor vessel, and during movement of irradiated fuel assemblies in secondary containment as applicable to each Function. The proposed Specification Applicability is the same as for the Secondary Containment Specifications in ITS Section 3.6. The justification for the differences between the current and proposed Applicability for Secondary Containment requirements is provided in the Discussion of Changes for ITS Section 3.6 "Containment Systems." Therefore, this change is administrative. This change is consistent with NUREG-1433.

A_7 Not used.

A_8 This proposed change deletes the line item for the quarterly Channel Functional Test. The Channel Calibration encompasses the Channel Functional Test. Since the Channel Calibration is also required quarterly, a separate line item for the Channel Functional Test is not required.

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 This change modifies current Technical Specification Action A (Table 3.2.D) to include also discontinuing OPDRVs (as a result of declaring the associated secondary containment isolation valves and standby gas treatment subsystem inoperable and taking the appropriate actions) if the channel is not placed in trip (placing the plant in a non-applicable Mode or Condition) due to specifying OPDRVs as an applicable Condition. Currently, only operation of the

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 (cont'd) refueling equipment has to cease. The addition of OPDRVs to the applicable Conditions further ensures that offsite dose limits will not be exceeded should fuel damage result from a vessel draindown event by discontinuing operations which could initiate an event. This change constitutes a more restrictive change. This change is consistent with NUREG-1433.

M_2 The proposed change adds two new Functions (Functions 1 and 2, as listed below). Along with these added Functions, Actions (A, B, and C) and Surveillance Requirements are provided. Action A requires the channel to be placed in trip if one or more channels are inoperable. The allowed outage time for Function 1 is 12 hours and for Function 2 is 12 hours. These times are based on the analyses in NEDC-31677P-A and NEDC-30851P-A. One hour is allowed to restore a loss of Function (Action B). If these requirements are not met within the Completion Times then Action C is entered which requires the associated secondary containment penetration flow path to be isolated or the SCIVs to be declared inoperable, and the SGT to be started or the SGT to be declared inoperable. Below is a list of the added Surveillance Requirements for each Function. The addition of new requirements (Functions with Actions and Surveillances) constitute a more restrictive change. This change is consistent with NUREG-1433.

1. Reactor Vessel Water Level—Low (Level 3)

Modes 1, 2, and 3, and during operations with a potential for draining the reactor vessel:

SR 3.3.6.2.1	Channel Check - 12 hours
SR 3.3.6.2.2	Channel Functional Test - 92 days
SR 3.3.6.2.4	Channel Calibration - 24 months
SR 3.3.6.2.5	Logic System Functional Test - 24 months

2. Drywell Pressure—High

Modes 1, 2, and 3:

SR 3.3.6.2.1	Channel Check - 12 hours
SR 3.3.6.2.2	Channel Functional Test - 92 days
SR 3.3.6.2.4	Channel Calibration - 24 months
SR 3.3.6.2.5	Logic System Functional Test - 24 months

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

M_3 This change increases the Surveillance Frequency for the Channel Check from daily to 12 hours. The Channel Check performed every 12 hours ensures that a gross failure of instrumentation has not occurred. Increasing Surveillance Frequencies constitutes a more restrictive change. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS

R_1 This change proposes to relocate the current "Trip Level Setting" column in current Technical Specifications Table 3.2.B and replace it with an "Allowable Value" column in the proposed Technical Specifications Table 3.3.6.2-1. Trip setpoints are an operational detail that is not directly related to the Operability of the instrumentation and will be relocated to a licensee controlled document. The Allowable Value is the required limitation for the parameter and this value will be inserted in the table. Any change to the trip setpoints will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_2 The change will relocate details relating to design and operations and items that are procedural in nature (e.g., specific instructions, etc.) to procedures. These details will be retained and will require a 10 CFR 50.59 review in order to be changed. This change is consistent with NUREG-1433.

R_3 System operational details (when not to place in trip) have been relocated to the Bases and procedures. These details are unnecessary in the LCO and can be adequately controlled in the Bases and procedures. Changes to the Bases will be controlled by the provisions of the Bases Control Process in Chapter 5 of the Technical Specifications. Changes to procedures will be controlled by the provisions of 10 CFR 50.59.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 This proposed change (proposed Condition C) modifies current Action B by adding the options of declaring secondary containment isolation valves or the Standby Gas Treatment System inoperable. The current requirement requires the secondary containment to be isolated and the Standby Gas Treatment (SGT) System to be started. By allowing the associated secondary containment isolation valves (SCIVs) to be

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 (cont'd) declared inoperable, the Actions of that Specification must be entered. This ensures the plant is within the bounds of the Technical Specifications and approved actions. The option to declare the SGT System inoperable is acceptable since this also ensures the plant is within the bounds of the Technical Specifications and approved actions. Declaring the associated SCIVs and SGT System inoperable is also acceptable since the Required Actions of the respective LCOs provide appropriate actions for the inoperable components. The 1 hour Completion Time is sufficient for plant operations personnel to establish required plant conditions or to declare the associated components inoperable without unnecessarily challenging plant systems. This change is consistent with NUREG-1433.

L_{av} This change revises the Technical Specification setpoints for proposed Section 3.3 instrumentation to reflect Allowable Values consistent with the philosophy of NUREG-1433. These Allowable Values (to be included in Technical Specifications) and the Trip Setpoints (to be included in plant procedures) have been established consistent with the PECO Energy Instrument Setpoint Methodology of the General Electric (GE) Instrument Setpoint Methodology; the PBAPS Units 2 & 3 specific safety analysis limits as modified by NEDC-32183P, "Power Rerate Safety Analysis Report for Peach Bottom 2 & 3," dated May 1993; and the uncertainties associated with the PBAPS Units 2 & 3 instrumentation. The setpoint evaluation used actual PBAPS physical data and operating practices to ensure the validity of the resulting Allowable Values and Trip Setpoints. Changes resulting from the Power Rerate analyses and the effect on safety analysis limits were previously evaluated in the licensee amendment requests (93-12) for Power Rerate (letter dated June 23, 1993, from G.A. Hunger (PECo) to NRC). All changes to safety analysis limits, applied in the methodologies, were evaluated and confirmed as ensuring safety analysis licensing acceptance limits are maintained. All design limits, applied in the methodologies, were confirmed as ensuring that applicable design requirements of the associated systems are maintained. The methodologies used to

TECHNICAL CHANGES - LESS RESTRICTIVE

L_{ev} (cont'd) derive the Allowable Values and Trip Setpoints are based on combining the uncertainties of the associated channels as documented in letter dated May 2, 1994 from G.A. Hunger (PECO Energy) to NRC responding to the Request for Additional Information Regarding Power Rerate Request dated March 29, 1994 (RAI-2). The methodologies used in the evaluation are consistent with the methodology used for Limerick Units 1 & 2 and documented in NEDC-31336, "General Electric Instrumentation Setpoint Methodology." The NRC approval of NEDC-31336 is documented in a Safety Evaluation Report transmitted by letter from B. Boger (NRC) to D. Roare (GE) dated February 9, 1993. In the methodologies, the Trip Setpoints take into consideration calibration accuracies which were specifically assumed in the PBAPS Unit 2 & 3 setpoint calculations. Plant calibration procedures will ensure the assumptions regarding calibration accuracy are maintained. The proposed Allowable Values and Trip Setpoints have been established from each design or safety analysis limit by accounting for instrument accuracy, calibration and drift uncertainties, as well as process measurement accuracy and primary element accuracy using the PECO Energy Instrument Setpoint Methodology or the GE Instrument Setpoint Methodology. The use of these methodologies for establishing Allowable Values and Trip Setpoints ensures design or safety analysis limits are not exceeded in the event of transients or accidents and accounts for uncertainties and environmental conditions.

DISCUSSION OF CHANGES
ITS 3.3.7.1: MAIN CONTROL ROOM EMERGENCY VENTILATION (MCREV) SYSTEM INSTRUMENTATION

ADMINISTRATIVE CHANGES

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 A proposed Note at the start of the Actions Table ("Separate Condition entry is allowed for each channel.") provides more explicit instructions for proper application for the new Actions for Technical Specification compliance. In conjunction with the proposed Specification 1.3 - "Completion Times," this Note provides direction consistent with the intent of the Required Actions for inoperable MCREV System instrumentation channels or trip systems. It is intended that each Required Action be applied regardless of it having been applied previously for other inoperable MCREV System instrumentation channels or trip systems.

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 The Frequency of the Channel Check requirement for the Control Room Air Intake Radiation—High Function has been increased from once per day to once per 12 hours. This change is consistent with NUREG-1433 and represents an additional restriction on plant operations.

M_2 Current Specification 3.11.A.5.b requires if one channel is inoperable or in trip in both trip systems that emergency ventilation be initiated and maintained, but specifies no Completion Time for the action. The proposed Action for this same Condition (Required Action A.1) requires the associated MCREV subsystem be declared inoperable within 1 hour from discovery that this Condition

TECHNICAL CHANGES - MORE RESTRICTIVE

M_2 cont'd) exists. The MCREV Specification (LCO 3.7.4) then provides the actions for the associated MCREV subsystems. The change is considered an additional restriction on plant operation since it provides a specific time period for completing the actions. In addition, declaring the associated MCREV subsystems inoperable will result in having to place the plant in a non-applicable Mode or Condition.

M_3 Current Specification 3.11.A.5.a specifies that "one radiation monitoring channel may be inoperable for 7 days, as long as the remaining radiation monitoring channel maintains the capability of initiating emergency ventilation on any designed trip functions." Proposed LCO 3.3.7.1, Condition A, will require that an inoperable channel be placed in trip within 6 hours in addition to the requirement that the associated MCREV subsystem be declared inoperable within one hour of discovery of loss of initiation capability in both trip systems. Although proposed LCO 3.3.7.1 permits operation with one channel in trip for an indefinite period (instead of 7 days as allowed by existing 3.11.A.5.a), the requirement that the inoperable channel be placed in trip within 6 hours is more restrictive because it re-establishes the capability to tolerate a single failure of an instrument channel within 6 hours. The proposed change is consistent with the analysis in GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications" (SER dated July 21, 1992). Confirmation of the applicability of GENE-770-06-1 to PBAPS for the MCREV system is documented in Technical Specification Change Request 90-03. This change is consistent with NUREG-1433.

M_4 Current Specification 3.11.A.7 requires that if the actions of existing Specification 3.11.A.5 or 3.11.A.6 cannot be met the MCREV be manually initiated and maintained, but specifies no completion Time for this action. The proposed Actions for the same Conditions (Required Actions B.1 and B.2) require the associated MCREV subsystem to be initiated within 1 hour or to declare the associated MCREV subsystem inoperable within 1 hour. Declaring the associated MCREV subsystem inoperable within 1 hour results in having to take the actions of Specification 3.7.4 for the associated subsystems. This change is considered an additional restriction on plant operation since it provides a specific time for completing the actions. In addition, declaring the associated MCREV subsystems inoperable will result in having to place the plant in a non-applicable Mode or Condition.

DISCUSSION OF CHANGES
ITS 3.3.7.1: MAIN CONTROL ROOM EMERGENCY VENTILATION (MCREV) SYSTEM INSTRUMENTATION

TECHNICAL CHANGES - RELOCATIONS

R_1 This change proposes to relocate the current "Trip Level Setting" column in current Technical Specifications Table 3.2.D and replace it with an "Allowable Value" column in proposed Technical Specification 3.3.7.1. Trip setpoints are an operational detail that is not directly related to the Operability of the instrumentation and will be relocated to a licensee controlled document.

R_2 This change proposes to relocate specific details about the instrument (number of channels provided by design, etc.) to the Bases. Placing these details in the Bases provides assurance they will be maintained. Changes to the Bases will be controlled using the Bases Control Process in Chapters 5 of the Technical Specifications.

R_3 The requirements for trip functions for the MCREV initiation instrumentation not associated with the Control Room Air Intake Radiation—High channels have been relocated to a licensee controlled document. These trip functions are not credited in the safety analysis for initiating the MCREV System. In addition, the functions to be relocated have no impact on the Control Room Air Intake Radiation—High channel Operability. Changes to these requirements will be controlled using 10 CFR 50.59. This change is consistent with NUREG-1433.

R_4 The proposed change will relocate items which are procedural in nature (e.g., conversions, specific instructions, etc.) to procedures. These items will be retained and will require a 10 CFR 50.59 review in order to be changed. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 The Surveillances have been modified by a Note to indicate that when a channel is placed in an inoperable status solely for the performance of required Surveillances, entry into the associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated function maintains MCREV System initiation capability. This change is acceptable because: a) the Note only applies when the MCREVS initiation function is maintained by the redundant Control Room Air Intake Radiation—High channels; and b) the 6 hour period is based on GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 (cont'd) Selected Instrumentation Technical Specifications" (SER dated July 21, 1992). Confirmation of the applicability of GENE-770-06-1 to PBAPS for the MCREV system is documented in Technical Specification Change Request 90-03. This change is consistent with NUREG-1433.

L_2 The Frequency for Surveillance 4.11.A.3 has been changed from 18 months to 24 months. In ITS, current Surveillance 4.11.A.3 requirements are addressed in the Logic System Functional Test (LSFT) for the MCREV System Instrumentation and the system functional test for the MCREV System. The current refueling outage, which is what the current test was originally based upon, is now 24 months. A review of the operating performance history of this requirement has shown that this SR has not failed due to a failure that is not related to an instrument failure (which would be detected during a CHANNEL FUNCTIONAL TEST) or a fan failure (which would be detected during the tests required by the VFTP). Therefore, extending the LSFT frequency is considered acceptable and is consistent with other similar Surveillances.

L_{av} This change revises the Technical Specification setpoints for proposed Section 3.3 instrumentation to reflect Allowable Values consistent with the philosophy of NUREG-1433. These Allowable Values (to be included in Technical Specifications) and the Trip Setpoints (to be included in plant procedures) have been established consistent with the PECO Energy Instrument Setpoint Methodology of the General Electric (GE) Instrument Setpoint Methodology; the PBAPS Units 2 & 3 specific safety analysis limits as modified by NEDC-32183P, "Power Rerate Safety Analysis Report for Peach Bottom 2 & 3," dated May 1993; and the uncertainties associated with the PBAPS Units 2 & 3 instrumentation. The setpoint evaluation used actual PBAPS physical data and operating practices to ensure the validity of the resulting Allowable Values and Trip Setpoints. Changes resulting from the Power Rerate analyses and the effect on safety analysis limits were previously evaluated in the licensee amendment requests (93-12) for Power Rerate (letter dated June 23, 1993, from G.A. Hunger (PECo) to NRC). All changes to safety analysis limits, applied in the methodologies, were evaluated and confirmed as ensuring safety analysis licensing acceptance limits are maintained. All design limits, applied in the methodologies, were confirmed as ensuring that applicable design requirements of the associated systems are maintained. The methodologies used to derive the Allowable Values and Trip Setpoints are based on combining the uncertainties of the associated channels as documented

TECHNICAL CHANGES - LESS RESTRICTIVE

L_{av} (cont'd) in letter dated May 2, 1994 from G.A. Hunger (PECO Energy) to NRC responding to the Request for Additional Information Regarding Power Rerate Request dated March 29, 1994 (RAI-2). The methodologies used in the evaluation are consistent with the methodology used for Limerick Units 1 & 2 and documented in NEDC-31336, "General Electric Instrumentation Setpoint Methodology." The NRC approval of NEDC-31336 is documented in a Safety Evaluation Report transmitted by letter from B. Boger (NRC) to D. Roare (GE) dated February 9, 1993. In the methodologies, the Trip Setpoints take into consideration calibration accuracies which were specifically assumed in the PBAPS Unit 2 & 3 setpoint calculations. Plant calibration procedures will ensure the assumptions regarding calibration accuracy are maintained. The proposed Allowable Values and Trip Setpoints have been established from each design or safety analysis limit by accounting for instrument accuracy, calibration and drift uncertainties, as well as process measurement accuracy and primary element accuracy using the PECO Energy Instrument Setpoint Methodology or the GE Instrument Setpoint Methodology. The use of these methodologies for establishing Allowable Values and Trip Setpoints ensures design or safety analysis limits are not exceeded in the event of transients or accidents and accounts for uncertainties and environmental conditions.

Specification 3.3.8.1 TSCR 90-03

~~LIMITING CONDITIONS FOR OPERATION~~

~~3.2 Protective Instrumentation (Continued)~~

A1

~~B. Core and Containment Cooling Systems Initiation and Control~~

LCO 3.3.8.1 The Loss of Power (A1)

~~Core and containment cooling system initiation and control~~ instrumentation for ~~each Trip~~ (A1) Function in Table ~~3.2.B~~ 3.3.8.1-1 shall be Operable; and, there shall be two Operable or tripped trip systems for each Trip Function except as noted in Table ~~3.2.B~~ 3.3.8.1-1.

(A1) Table 3.3.8.1-1

SR 3.3.8.1.5 (M3)

ACTIONS (A1)

Applicability:

~~Each Trip Function listed in Table 3.2.B shall be Operable whenever the system(s) it initiates or controls are required to be Operable as specified in Section 3.5.~~

(A4) When the associated diesel generators and offsite circuit are required to be OPERABLE by LCO 3.8.1, "AC Sources-Operating," and LCO 3.8.2, "AC Sources-Shutdown"

Conditions and Required Actions:

With one or more channel(s) required by Table ~~3.2.B~~ inoperable in one or more ~~Trip~~ Functions, take the Action required by Table ~~3.2.B~~ 3.3.8.1-1 (A1)

Action A (A1)

Add Note to Actions (A3)

~~LIMITING CONDITIONS FOR OPERATION~~

~~4.2 Protective Instrumentation (Continued)~~

~~B. Core and Containment Cooling Systems Initiation and Control~~

Instrumentation shall be functionally tested, calibrated and checked as indicated in Table ~~4.2.B~~ 3.3.8.1-1 (A1)

System logic shall be functionally tested as indicated in Table ~~4.2.B~~ 3.3.8.1-1 (A1).

Surveillance Requirements Note 1 (A1)

(M3)

Unit 3 LOP Instrumentation Requirements

Required Actions ~~[illegible]~~

A.1 and B.1

Required Actions

L3

M4

C.1

Proposed Note to Actions B and C

A1

NOTES FOR TABLE 3.2.B

1\. With one or more required channel(s) inoperable in one or more Trip Functions, place channel in trip within one hour or the reactor shall be placed in the Cold Shutdown Condition within 24 hours.

Replace with Action D

L2

2\. Close isolation valves in RCIC subsystem.

3\. Close isolation valves in HPCI subsystem.

See Discussion of changes for ITS 3.3.6.1, "PCI Instrumentation"

4\. Instrument setpoint corresponds to 378 inches above vessel zero.

5\. HPCI has only one trip system for these sensors.

See Discussion of changes for ITS 3.3.5.1, "ECCS Instrumentation"

6\. Deleted

See Discussion of changes for ITS 3.8.1, "A.C. Sources-Operating"

7\. The failure of a 480V Emergency Load Center timer could result in the failure of a 480V Emergency Load Center to re-energize following the loss of one or both offsite sources. Therefore, Technical Specification 3.9.B.7 will apply when a 480V Emergency Load Center timer is not Operable.

8\. With one or more required channel(s) inoperable in one or more Trip Functions:
   1. Within 24 hours, place inoperable channel in trip; and,
   2. Within one hour from discovery of loss of feature initiation capability in both trip systems for feature(s) supported by this trip function, declare supported feature(s) inoperable (See Footnote (1)).
   3. If required actions and associated completion times of Action 1 or 2 are not met, declare associated supported features inoperable immediately.

9\. With one or more required channel(s) inoperable in one or more Trip Functions:
   1. Within 24 hours, restore channel to Operable status; and,
   2. Within one hour from discovery of loss of initiation capability in both trip systems for feature(s) supported by this trip function, declare supported feature(s) inoperable(See Footnote (2)).
   3. If required actions and associated completion times of Action 1 or 2 are not met, declare associated supported features inoperable immediately.

10\. With one or more required channel(s) inoperable in one or more Trip Functions:
   1. Within 24 hours, place inoperable channel in trip or align affected (HPCI or RCIC) pump suction to suppression pool; and,
   2. Within one hour of discovery of loss of initiation capability, declare affected system (HPCI or RCIC) inoperable if associated pump suction is not aligned to suppression pool.
   3. If required actions and associated completion times of Action 1 or 2 are not met, declare associated system inoperable immediately.

---

(1) Only applicable to the High Drywell Pressure and Reactor Low-Low-Low Water Level functions.

(2) Not applicable to Reactor High Water level Function.

See Discussion of changes for ITS 3.3.5.1 "ECCS Instrumentation"

See Discussion of changes for ITS 3.3.5.2, "RCIC System Instrumentation"

~~LIMITING CONDITIONS FOR OPERATION~~ A

~~3.2 Protective Instrumentation (Continued)~~ R

A1

~~B. Core and Containment Cooling Systems - Initiation and Control~~ A

LCO 3.3.8.1

The Loss of Power

~~Core and containment cooling system initiation~~ A ~~and control~~ instrumentation for ~~each Trip~~ A1 3.3.8.1-1 Function in Table ~~3.2.B~~ shall be Operable; and there shall be two Operable or tripped trip systems for each Trip Function except as noted in Table ~~3.2.B~~ 3.3.8.1-1 A1

Table 3.3.8.1-1

Actions A1

Applicability:

~~Each Trip Function listed in Table 3.2.B shall be Operable whenever the system(s) it initiates or controls are required to be Operable as specified in Section 3.5.~~ R

A4

When the associated diesel generators and offsite circuit are required to be OPERABLE by LCO 3.8.1, "AC Sources - Operating," and LCO 3.8.2, "AC Sources - Shutdown"

B

Conditions and Required Actions:

With one or more channel(s) required by Table ~~3.2.B~~ 3.3.8.1-1 inoperable in one or more Trip Functions, take the Action required by Table ~~3.2.B~~. Action A A1

3.3.8.1-1 A1

A2 Add Note to Actions

M3

Unit 3 LOP Instrumentation Requirements

~~LIMITING CONDITIONS FOR OPERATION~~ A

~~4.2 Protective Instrumentation (Continued)~~ R

~~B. Core and Containment Cooling Systems - Initiation and Control~~ A

Instrumentation shall be functionally tested, calibrated and checked as indicated in Table ~~4.2.B~~ A 3.3.8.1-1 A1

A1 System logic shall be functionally tested as indicated in Table ~~4.2.B~~ 3.3.8.1-1 A1

SR 3.3.8.1.5 M3

A1 Surveillance Requirement Note 1

Required Action

PBAPS

C.1

Required Action

NOTES FOR TABLE 3.2.B L3

Proposed Note to Actions B and C M4

A.1

A.1 and B.1

1\. With one or more required channel(s) inoperable in one or more Trip Functions, place channel in trip within one hour or the reactor shall be placed in the Cold Shutdown Condition within 24 hours.

L2

Replace with Action D

2\. Close isolation valves in RCIC subsystem.

See Discussion of changes for ITS 3.3.6.1, "PCI Instrumentation"

3\. Close isolation valves in HPCI subsystem.

4\. Instrument setpoint corresponds to 378 inches above vessel zero.

See Discussion of Changes for ITS 3.3.5.1, "ECCS Instrumentation"

5\. HPCI has only one trip system for these sensors.

6\. Deleted

See Discussion of changes for ITS 3.8.1, "AC Sources-Operating"

7\. The failure of a 480V Emergency Load Center timer could result in the failure of a 480V Emergency Load Center to re-energize following the loss of one or both offsite sources. Therefore, Technical Specification 3.9.B.7 will apply when a 480V Emergency Load Center timer is not Operable.

8\. With one or more required channel(s) inoperable in one or more Trip Functions:

1. Within 24 hours, place inoperable channel in trip; and,
2. Within one hour from discovery of loss of feature initiation capability in both trip systems for feature(s) supported by this trip function, declare supported feature(s) inoperable (See Footnote (1)).
3. If required actions and associated completion times of Action 1 or 2 are not met, declare associated supported features inoperable immediately.

9\. With one or more required channel(s) inoperable in one or more Trip Functions:

1. Within 24 hours, restore channel to Operable status; and,
2. Within one hour from discovery of loss of initiation capability in both trip systems for feature(s) supported by this trip function, declare supported feature(s) inoperable(See Footnote (2)).
3. If required actions and associated completion times of Action 1 or 2 are not met, declare associated supported features inoperable immediately.

10\. With one or more required channel(s) inoperable in one or more Trip Functions:

1. Within 24 hours, place inoperable channel in trip or align affected (HPCI or RCIC) pump suction to suppression pool; and,
2. Within one hour of discovery of loss of initiation capability, declare affected system (HPCI or RCIC) inoperable if associated pump suction is not aligned to suppression pool.
3. If required actions and associated completion times of Action 1 or 2 are not met, declare associated system inoperable immediately.

(1) Only applicable to the High Drywell Pressure and Reactor Low-Low-Low Water Level functions.

(2) Not applicable to Reactor High Water level Function.

See Discussion of changes for ITS 3.3.5.1, "ECCS Instrumentation"

See Discussion of changes for ITS 3.3.5.2, "RCIC System Instrumentation"

DISCUSSION OF CHANGES
ITS 3.3.8.1: LOSS OF POWER (LOP) INSTRUMENTATION

ADMINISTRATIVE CHANGES

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 This change will replace the current "Minimum No. of Operable Instrument Channels Per Trip System" and "Number of Instrument Channels Provided by Design," columns with a "Required Channels Per Bus" column. This specifies the number of channels required to be Operable to ensure a DG start when required. This change is consistent with NUREG-1433.

A_3 This change proposes to add a Note which will allow separate Condition entry for each channel. This change provides more explicit instructions for proper application of the Actions for Technical Specifications compliance. In conjunction with the proposed Specification 1.3 - "Completion Times," the Note ("Separate Condition entry ...") and "in one or more Functions" provides more explicit direction of the current interpretation of the existing Specifications. This change is considered administrative and is consistent with NUREG-1433.

A_4 The current Applicability for the LOP Instrumentation is when the system(s) it initiates or controls are required to be Operable. This proposed change adds the specific Applicability for LOP Instrumentation by referring to the applicable AC Sources Specification (LCO 3.8.1 or LCO 3.8.2). Based on this the proposed change is considered to be administrative. B

ADMINISTRATIVE CHANGES (continued)

A_5 This change replaces the Trip Level Setting Value with the Allowable Value for the Loss of Power Instrumentation Functions. The current Technical Specification (CTS) Trip Level Setting Values are the same as the proposed Allowable Values and have been treated as the Allowable Values. These values were derived from the limiting values of the process parameters obtained from the safety analysis and corrected for calibration, process, and some of the instrument errors. Since the CTS values are the same as the proposed values this change is considered administrative.

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 The proposed change adds a new subfunction to each of the Degraded Voltage Functions in the LOP Instrumentation Table. The added Functions (2.b, 3.b, 4.b, and 5.b) are the Time Delays for the DG start signal on a degraded voltage condition. Along with these added subfunctions are added Actions and Surveillance Requirements. The addition of new requirements constitute a more restrictive change. This change is consistent with NUREG-1433. Below is a list of the added Surveillance Requirements and associated Frequency.

SR 3.3.8.1.1 Channel Functional Test - 31 days
SR 3.3.8.1.2 Channel Calibration - 18 months
SR 3.3.8.1.4 Logic System Functional Test - 24 months

M_2 The proposed change adds a new Surveillance Requirement (SR 3.3.8.1.4, Logic System Functional Test) to the LOP Instrumentation Functions. The change adds SR 3.3.8.1.4 for the Loss of Voltage and Degraded Voltage Functions. The addition of new requirements constitutes a more restrictive change. This change is consistent with NUREG-1433.

M_3 Since Unit 2(3) requires some equipment powered from Unit 3(2) sources to be OPERABLE, LOP instruments that transfer offsite circuits and start DGs due to loss of power to a Unit 3(2) emergency bus is needed. Therefore, each unit now requires the opposite units LOP instrumentation Functions 1, 2, 3, and 5 to be OPERABLE. Appropriate Actions and SRs have also been added. The addition of new requirements constitutes a more restrictive change.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

M_4 A new Note has been added to Actions A, B, and C. This note will require an offsite circuit to be declared inoperable, if placing a channel in trip results in inoperability of the offsite circuit. The addition of new requirements constitutes a more restrictive change.

TECHNICAL CHANGES - RELOCATIONS

R_1 The change will relocate items which are procedural in nature (e.g., conversions, specific instructions, etc.) to procedures. These items will be retained and will require a 10 CFR 50.59 review in order to be changed. This change is consistent with NUREG-1433.

R_2 This change proposes to relocate the current "Trip Level Setting" column in current Technical Specifications Table 3.2.B and replace it with an "Allowable Value" column in the proposed Technical Specifications Table 3.3.8.1-1. Trip setpoints are an operational detail that is not directly related to the Operability of the instrumentation and will be relocated to a licensee controlled document. The Allowable Value is the required limitation for the parameter and this value will be inserted in the table. Any change to the trip setpoints will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_3 This change proposes to relocate specifics about the instruments (the specific function(s) they perform, etc.) to the UFSAR/Bases. Any changes to these requirements will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_4 This change proposes to relocate the Trip Level Setting for the 4 kV Emergency Bus Undervoltage Relay. Trip setpoints are an optional detail that is not directly related to the Operability of the instrumentation and will be relocated to a licensee controlled document. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 This change proposes to add a Note (Note 2) to the Surveillance Requirements which will allow a 2 hour delay from entering into the associated Conditions and Required Actions for a channel placed in an inoperable status solely for performance of required Surveillances provided the associated Function maintains initiation capability for three diesel generators or undervoltage transfer capability for three 4 kV emergency buses. The loss of Function is acceptable in this case since only three of the four DGs are required to start within the required time. The short period of time (2 hours) in this Condition will have no appreciable impact on risk. Also, upon completion of the Surveillance, or expiration of the 2 hour allowance, the channel must be returned to Operable status or the applicable Condition entered and Required Actions taken.

L_2 The proposed change requires the associated diesel generators (DGs) to be declared inoperable immediately if the Required Actions of Conditions A, B, or C cannot be met. The current requirements require that if the Actions cannot be met the reactor must be placed in the Shutdown Condition within 24 hours. By declaring the DG inoperable and taking the actions of the DG, the plant is within the bounds of the Technical Specifications and approved actions. Therefore, this action is appropriate since the LOP Instrumentation may be incapable of performing the intended function (starting the associated DGs), and the supported features (DGs) associated with the inoperable untripped channels must be declared inoperable immediately. This change is consistent with NUREG-1433.

L_3 This change proposes to extend the allowed outage times (AOTs) for Degraded Voltage High Setting and Degraded Voltage Non-LOCA Functions (Functions 3 and 5, respectively, of Table 3.3.8.1-1) from 1 hour to the following:

14 days in proposed Condition A when one or two Function 3 channels are inoperable on one 4 kV emergency bus; or

14 days in proposed Condition A when one or two Function 5 channels are inoperable on one 4 kV emergency bus; or

24 hours in proposed Condition B when one Function 3 channel is inoperable on each of two 4 kV emergency buses; or

24 hours in proposed Condition B when one Function 5 channel is inoperable on each of two 4 kV emergency buses; or

B

TECHNICAL CHANGES - LESS RESTRICTIVE

L_3 (cont'd) 24 hours in proposed Condition B when one Function 3 channel is inoperable on one 4 kV emergency bus and one Function 5 channel is inoperable on a different 4 kV emergency bus.

During MODES 1, 2, and 3, four 4 kV emergency buses from the subject unit and at least two 4 kV emergency buses from the opposite unit are required to have OPERABLE LOP instrumentation. During other MODES or conditions, at least two 4 kV emergency buses from the subject unit and at least one 4 kV emergency bus from the opposite unit are required to have OPERABLE LOP instrumentation. The actual number of 4 kV emergency buses and, as a result, the LOP instrumentation channels required will vary depending on which components are being credited with satisfying Technical Specification requirements and from where these components are being powered.

The 14 day allowed outage time (AOT) when one or two Function 3 channels or when one or two Function 5 channels are inoperable on one 4 kV emergency bus is acceptable because these relays provide only a marginal increase in the voltage monitoring scheme (there is only a small range where the relay protection provided by either of these relays does not overlap with other voltage monitoring relays). In this Condition, autotransfer capability from the normal offsite power source to the alternate power source may be lost from Function 3 or 5 channels for one 4 kV emergency bus. However, autotransfer capability will still be provided by the remaining Function 3 or 5 channels on the affected 4 kV emergency bus while maintaining adequate protection for equipment powered from the affected bus. Therefore, this change has no adverse impact on plant operation. In addition, the probability of the grid operating in this unprotected band is extremely remote. There has been no historical evidence of the grid operating in these bands for sufficient time that would have caused operation of these relays. Manual actions can also be taken on the 4 kV emergency bus with the inoperable channels as a result of observed automatic actions on the other 4 kV emergency buses with OPERABLE channels. (The number of other 4 kV emergency buses available with OPERABLE LOP instrumentation channels is based on the number of required 4 kV emergency buses discussed in the previous paragraph.) These actions (manually transferring the 4 kV emergency bus power supply to the alternate source) can be performed without detriment to plant equipment. B

TECHNICAL CHANGES - LESS RESTRICTIVE

L_3 (cont'd) The 24 hour AOT when two 4 kV emergency buses have one required Function 3 channel inoperable, or when two 4 kV emergency buses have one required Function 5 channel inoperable, or when one 4 kV emergency bus has one required Function 3 channel inoperable and a different 4 kV emergency bus has one required Function 5 channel inoperable is acceptable based on the discussions above, except that in Condition B autotransfer capability may be lost for the two affected 4 kV emergency buses. Since the degradation addressed in Condition B is more severe than the degradation addressed in Condition A (two 4 kV emergency buses are impacted in Condition B, but only one 4 kV emergency bus is impacted in Condition A), the proposed AOT for Condition B is reduced to 24 hours from the proposed 14 day AOT specified for Condition A. B

L_4 The change proposes to delete the requirement for a Channel Calibration on the undervoltage relay for the Loss of Voltage Function. The current Technical Specifications require a Channel Calibration once per 5 years. The design intent of the undervoltage relays for the Loss of Voltage Function is to monitor the gross availability of voltage on the respective emergency bus. The relay makes no determination concerning the quality of the voltage. The functional requirements are that the relays operate (de-energize) when there is no source of voltage to the bus, and that it not operate during the load sequencing. These results are achieved by the design process of selecting a device whose dropout is substantially below the anticipated lowest voltage observed during the sequencing, and by functionally verifying that it drops out when the bus is de-energized and that it does not drop out during the sequencing. A Channel Calibration is therefore not required for the undervoltage relay to perform to satisfy its safety function (starting the DG on a loss of voltage on the emergency bus). The Channel Functional Test will still be performed once per 24 months to ensure that the DG does start on a loss of voltage.

DISCUSSION OF CHANGES
ITS 3.3.8.2: RPS ELECTRIC POWER MONITORING

ADMINISTRATIVE CHANGES

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 The Applicability of the RPS electric power monitoring assemblies has been specified consistent with the Applicability of the RPS Functions. As such, the change is considered administrative in nature.

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 If one RPS electric power monitoring assembly per RPS MG set or alternate power supply is inoperable or bypassed and not restored within 72 hours, current Specifications 3.1.D.1 and 3.1.D.2 allow 30 minutes to transfer the RPS bus to the alternate source or de-energize the bus. However, the proposed change for this condition would require placing the plant in a non-applicable Mode or Condition (Actions C and D) if transfer or deenergization is not accomplished within the 72 hour restoration time. As such, the change is an additional restriction on plant operation and is consistent with NUREG-1433.

M_2 An additional Surveillance has been provided (SR 3.3.8.2.4) to perform a system functional test once per 24 months. This Surveillance demonstrates that with a system actuation signal, the logic of the system will automatically trip open the associated RPS electric power monitoring assembly. This change represents an additional restriction on plant operation.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

M_3 Time delay setting requirements have been added for the undervoltage and overvoltage protective devices of the RPS MG set and the underfrequency and overvoltage protective devices of the RPS alternate power supply. These devices have adjustable time delay settings. This change represents an additional restriction on plant operations necessary to ensure no abnormal voltage or frequency condition can preclude the function of RPS bus powered components.

TECHNICAL CHANGES - RELOCATIONS

R_1 The details of what constitutes a trip train (an electric power monitoring assembly) have been relocated to the Bases. Placing these details in the Bases provides assurance that they will be maintained. Changes to the Bases will be controlled using the Bases Control Process in Chapter 5.0 of the Technical Specifications.

R_2 This change proposes to relocate the current maximum setpoint for the undervoltage and underfrequency relays, and the minimum setpoint for the overvoltage relay and underfrequency time delay relay in current Technical Specifications 4.1.D.1 and 4.1.D.2. These setpoints are an operational detail that is not directly related to the Operability of the instrumentation and will be relocated to a licensee controlled document. The Allowable Value is the required limitation for the parameter and this value will be maintained in the applicable SRs. Any change to the relocated setpoints will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 The Completion Time allowed to de-energize the bus when both electric power monitoring assemblies of a power supply are inoperable has been extended from 30 minutes to 1 hour. The 1 hour Completion Time is considered justified because it minimizes risk while allowing time for restoration or removal from service of the electric power monitoring assemblies.

L_2 A Note has been added to this Surveillance (SR 3.3.8.2.1) such that the Surveillance is only required to be performed when the unit is in Mode 4 ≥ 24 hours. Thus, the 6 month Frequency would not have to be met until a shutdown to Mode 4 for ≥ 24 hours occurs. The performance of this Surveillance could result in half-scrams, actual

TECHNICAL CHANGES - LESS RESTRICTIVE

L_2 (cont'd) valve isolations, and other plant perturbations, since if the assembly opens, power is lost. The test requirement has been changed to allow it to be performed while shutdown to minimize the impact of this Surveillance on plant operation. This change is consistent with the guidance in NRC Generic Letter 91-09 and will reduce the possibility of inadvertent trips and challenges to safety systems.

ADMINISTRATIVE CHANGES

None

TECHNICAL CHANGES - MORE RESTRICTIVE

None

TECHNICAL CHANGES - RELOCATIONS

R_1 This proposed change will relocate CTS 3/4.15, "Seismic Monitoring Instrumentation," and associated Bases to a licensee controlled document. This Specification provides the requirements for the seismic monitors and recorders. The seismic monitors and recorders function to determine the magnitude of a seismic event. These instruments do not perform any automatic action. They are used to measure the magnitude of a seismic event to ensure the design margins for plant equipment and structures have not been violated. These instruments do not meet any criteria in the NRC Policy Statement. Therefore, per the NRC Policy Statement, this Specification can be relocated out of Technical Specifications. Any changes to these requirements will require a 10 CFR 50.59 evaluation. The change is consistent with NUREG-1433.

TECHNICAL CHANGES - LESS RESTRICTIVE

None

DISCUSSION OF CHANGES
ITS 3.3: INSTRUMENTATION BASES

The Bases of the current Technical Specifications for this section (pages 18 through 21, 23, 47 through 51, 53a, 54, 89 through 94, 97, and 240w) have been completely replaced by revised Bases that reflect the format and applicable content of proposed PBAPS Units 2 and 3 Technical Specifications Section 3.3, consistent with NUREG-1433. The revised Bases are as shown in the proposed PBAPS Units 2 and 3 Bases. In addition, pages 22, 36a, 52, 53, 55, 56, 95, 96, and 98, which are blank pages, have been deleted.

Specification 3.4.1

Note to LCO 3.4.1 L1

B

A1 ~~LIMITING CONDITION FOR OPERATION~~ A1 ~~SURVEILLANCE REQUIREMENTS~~

3.4.1 ~~3.6.F~~ RECIRCULATION ~~PUMPS~~ Loops Operating

~~4.6.F RECIRCULATION PUMPS~~

R1 1. Following one-pump operation, the discharge valve of the low speed pump may not be opened unless the speed of the faster pump is less than 50% of its rated speed.

A1 Action D — Requirements of the LCO not met for reasons other than Conditions A, B, C, and F. Satisfy the requirements of the LCO within 24 hours. L1

B1 LCO 3.4.1 — 2. The requirements applicable to single loop operation as identified in ~~sections 1.1.A, 2.1.A, 2.1.B, 3.5.Y & 3.5.X~~ shall be ~~initiated within 8~~ satisfied within 24 hours following the removal of one recirculation loop from service, or the unit placed in Hot Shutdown condition within the following ~~6~~ 12 hours. L1 L2

A1 Required Action D.1

A1 Required Action E.1

A1 LCO 3.4.1 Applicability Modes 1 and 2 A1 — 3. Whenever the reactor is in ~~the startup or run modes,~~ two reactor coolant system recirculation loops shall be in operation with matched flows A1 and ~~the reactor shall not be operated in REGIONS 1 or 2 of Figure 3.6.5 (defined below),~~ Core flow as a function of THERMAL POWER in the "Unrestricted" Region of Figure 3.4.1-1 P1 ~~except as specified in 3.6.F.4 and 3.6.F.5~~

A1 Figure 3.4.1-1 & Condition C — ~~a.~~ ~~REGION 1~~ - Total core flow less than 39% of rated and Thermal Power greater than the limit specified by Line A in Figure 3.6.5.

A1 Figure 3.4.1-1 — ~~b.~~ ~~REGION 2~~ - Total core flow greater than or equal to 39% of rated, but less than or equal to 45% of rated and Thermal Power greater than the limit specified by Line A in Figure 3.6.5.

"Restricted" Region A1

A1 Condition C — ~~4.~~ With only one reactor coolant system recirculation loop operating, ~~immediately initiate action to avoid operation in REGION 1.~~ R3 Thermal Power shall be reduced and be ~~below the limit specified by Line A in Figure 3.6.5~~ in the "Unrestricted" Region of Figure 3.4.1-1 A1 within 4 hours or core flow shall be increased to greater than or equal to 39% of rated core flow within 4 hours.

Required Action C.1

A1 Required Action C.2

M1 SR 3.4.1.2 →

R2 1. Establish baseline APRM and LPRM neutron flux noise values for each operating mode at or below the Thermal Power specified by Line A in Figure 3.6.5 for the region for which monitoring is required (Specification 3.6.F.5, REGIONS 1 and 2) within 2 hours of entering the region for which monitoring is required unless baselining has previously been performed since the last refueling outage.

A1
b. ~~a.~~ LCO 3.2.2, "MCPR"
c. ~~b.~~ LCO 3.3.1.1, "RPS Inst," Function 2.b (APRM)
a. LCO 3.2.1 "APLHGR"

A

Specification 3.4.1

NOTE to LCO 3.4.1 (L1)

PBAPS Unit 2

~~LIMITING CONDITION FOR OPERATION~~ ~~SURVEILLANCE REQUIREMENTS~~

(A1) 3.4.1 ~~3.6.F~~ RECIRCULATION ~~PUMPS~~ Loops Operating (A1) ~~4.6.F RECIRCULATION PUMPS~~

~~1. Following one-pump operation, the discharge valve of the low speed pump may not be opened unless the speed of the faster pump is less than 50% of its rated speed.~~ (R1)

~~1. Establish baseline APRM and LPRM neutron flux noise values for each operating mode at or below the Thermal Power specified by Line A in Figure 3.6.5 for the region for which monitoring is required (Specification 3.6.F.5, REGIONS 1 and 2) within 2 hours of entering the region for which monitoring is required unless baselining has previously been performed since the last refueling outage.~~ (R2)

(A1) Action D: Requirements of the LCO not met for reasons other than Conditions A, B, C and F, satisfy the requirements of the LCO within (24) hours. (L1)

LCO 3.4.1 (A1) ~~2.~~ The requirements applicable to single loop operation as identified in ~~sections 1.1.A, 2.1.A, 2.1.B, 3.5.I & 3.5.K~~

(A1) a. LCO 3.2.1, "APLHGR" ...
b. LCO 3.2.2, "MCPR" ...
c. LCO 3.3.1.1, "RPS Inst, Function 2.b (APRM)...

Required Action D.1 (A1) shall be ~~initiated within 24~~ satisfied within 24 (L1) hours following the removal of one recirculation loop from service, or the unit placed in Hot Shutdown condition within the following ~~6~~ 12 hours. (L2)

Required Action E.1

LCO 3.4.1 APPLICABILITY (A1) ~~3.~~ Whenever the reactor is in ~~the startup or run modes~~ MODES 1 and 2 (A1), two reactor coolant system recirculation loops with matched flows (A1) shall be in operation ~~and the reactor shall not be operated in REGIONS 1 or 2 of Figure 3.6.5 (defined below), except as specified in 3.6.F.4 and 3.6.F.5~~ with core flow as a function of THERMAL POWER in the "Unrestricted" Region of Figure 3.4.1-1 (A1)

Figure 3.4.1-1 & Condition C (A1)

~~a.~~ ~~REGION 1~~ - Total core flow less than 39% of rated and Thermal Power greater than the limit specified by Line A in Figure 3.6.5.

"Restricted" Region (A1)

Figure 3.4.1-1 (A1)

~~b.~~ ~~REGION 2~~ - Total core flow greater than or equal to 39% of rated, but less than or equal to 45% of rated and Thermal Power greater than the limit specified by Line A in Figure 3.6.5.

Condition C (A1) ~~4.~~ With only one reactor coolant system ~~recirculation loop operating, immediately initiate action to avoid operation in REGION 1.~~ (R3) Thermal Power shall be reduced and be ~~below the limit specified by Line A in Figure 3.6.5~~ in the "Unrestricted" Region of Figure 3.4.1-1 (A1) within 4 hours or core flow shall be increased to greater than or equal to 39% of rated core flow within 4 hours.

Required Action C.1

Required Action C.2 (A1)

(M1) SR 3.4.1.2

page 6 of 8

3. Specification 3.3.8.1, Loss of Power Instrumentation, ACTIONS, pages 3.3-61 through 3.3-63, 3.3-65, B3.3-188, and B3.3-190 through B3.3-195 (continued)

As a result, the ACTIONS for Specification 3.3.8.1 have been revised to reflect these agreements. Corresponding changes to the Bases for the ACTIONS of Specification 3.3.8.1 have also been made.

Corresponding changes have also been made to the CTS markups for Specification 3.3.8.1 on pages 1 of 12 and 5 of 12 (Unit 2) and on pages 7 of 12 and 11 of 12 (Unit 3), to the Discussion of Changes A_4, M_4, and L_3 for ITS 3.3.8.1 (pages 77, 79, 80, 81, and 82) and to the 10CFR50.92 evaluations A_4, M_4, and L_3 for ITS 3.3.8.1 (pages 20, 40, 140, 141, 142, and 143).

4. LCO 3.4.1, Recirculation Loops Operating, Note for Single Recirculation Loop Operation, pages 3.4-1 and B3.4-5

In Table 3.3.1.1-1 of Specification 3.3.1.1, Reactor Protection System, an Allowable Value for the Average Power Range Monitor (APRM) Flow Biased High Scram during single loop operation is specified. Specification 3.4.1, Recirculation Loops Operating, specifies single loop operation limits including resetting the APRM Flow Biased High Scram Allowable Value. Required Action D.1 of Specification 3.4.1 allows 24 hours to satisfy the LCO. This would allow 24 hours to recalibrate the APRM Flow Biased High Scram setpoints if the unit was going to stay in single loop operation. However, as proposed in TSCR 93-16, this must be done using the provisions of Required Action D.1 of Specification 3.4.1. As a result, since the ACTIONS of Specification 3.4.1 are entered to establish the single loop operation limits, it could be misinterpreted that the APRM Flow Biased High Scram Function is inoperable and the ACTIONS of Specification 3.3.1.1 must also be entered.

In order to eliminate any confusion brought on by the inconsistency with Specification 3.3.1.1, Reactor Protection System Instrumentation, and the need to enter Condition D of Specification 3.4.1, Recirculation Loops Operating, just to transition from two loop operation to single loop operation (Condition D allows 24 hours to reset the APRM settings to the single loop values, but Specification 3.3.1.1 does not provide a 24 hour Completion Time for inoperable APRM channels) a Note is proposed to be added to LCO 3.4.1. The

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 A Note to LCO 3.4.1 which states "Required limit modifications for single recirculation loop operation may be delayed for up to 12 hours after transition from two recirculation loop operation to single loop operation" is proposed to be added to the PBAPS Technical Specifications. The addition of the proposed Note will eliminate any confusion brought on by the inconsistency with Specification 3.3.1.1, Reactor Protection System Instrumentation, and the need to enter Condition D of Specification 3.4.1, Recirculation Loops Operating, just to transition from two loop operation to single loop operation (Condition D allows 24 hours to reset the APRM settings to the single loop values, but Specification 3.3.1.1 does not provide a 24 hour Completion Time for inoperable APRM channels). The proposed Note extends the time to implement the single loop operation requirements from 6 hours to 12 hours. This change also relaxes the allowed outage time from 6 hours to 24 hours to comply with the LCO when the reason for non-compliance is not related to thermal hydraulic stability. Relaxing the time to complete limit modifications for single loop operation or to restore compliance with the LCO in this condition is reasonable considering the low probability of an accident occurring during this period, the time required to perform the Required Action and the frequent core monitoring by operators allowing abrupt changes in core flow conditions to be quickly detected. The consequences of an accident are unchanged by adding additional time to complete limit modifications for single loop operation or to restore compliance with the LCO. Also, allowing this extended time will potentially avoid a plant transient caused by a plant shutdown and does not represent a significant decrease in safety. B B B

L_2 This change relaxes the time required to bring the plant to a Mode in which the LCO does not apply. It changes the time to bring the plant to Mode 3 from 6 hours to 12 hours. This proposed Completion Time is based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. The probability of an accident is not increased because the time allowed to restore the recirculation loops is not a precursor to any accident. Also the consequences of an accident occurring in the additional 6 hours allowed to reach Mode 3 are unchanged. The additional time also allows for a more controlled reduction in power.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L_3 This change adds a note which states the Surveillance is not required to be performed until 24 hours after both recirculation loops are in operation. The Surveillance is not required to be performed until both loops are operating since the mismatch limits are meaningless during single loop or natural circulation operation. Also, the Surveillance is allowed to be delayed 24 hours after both recirculation loops are operating. This allows for time to establish appropriate conditions for the test to be performed.

Specification 3.4.2

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

Unit 2

L1

3.4 Reactor Coolant System (RCS) A1

PBAPS

A1

~~LIMITING CONDITION FOR OPERATION~~

4.3 3.6.E Jet Pumps

A1 APPLICABILITY LCO 3.4.2

1. ~~Whenever the reactor is in the~~ startup or run modes, all jet pumps shall be operable. If it is determined that a jet pump is inoperable, an orderly shutdown shall be initiated and the reactor shall be in a ~~Cold Shutdown within 24 hours.~~

A1 MODES 1 and 2

ACTION A

MODE 3 in 12 hours L4

X

2. Flow indications from each of the 20 jet pumps during two loop operation or 10 jet pumps during single loop operation shall be verified prior to initiation of reactor startup from a cold shutdown condition.

R1

3. The indicated core flow is the sum of the flow indication from each of the 20 jet pumps. Flow indication from no more than one jet pump shall be unavailable during two loop operation. If two or more jet pump flow indication failures occur during two loop operation, an orderly shutdown shall be initiated within 12 hours and the reactor shall be in cold shutdown condition within the following 24 hours.

4. During single loop operation, no jet pump flow indication failures in the operating loop are permissible. If a jet pump flow indication failure occurs during single loop operation, an orderly shutdown shall be initiated within 12 hours and the reactor shall be in cold shutdown condition within the following 24 hours.

L3

M2

a. Recirculation pump flow to speed ratio differs by ≤ 5% from established patterns, and jet pump loop flow to recirculation pump speed ratio differs by ≤ 5% from established patterns.

c. Each jet pump flow differs by ≤ 10% from established patterns

~~SURVEILLANCE REQUIREMENTS~~

~~4.6.E Jet Pumps~~ SR 3.4.2.1

1. Whenever there is recirculation flow with the reactor in the startup or run modes, jet pump operability shall be checked daily by verifying that the following conditions do not occur simultaneously:

A2

- Verify at least one of the following criteria (a, b, or c) is satisfied for each operating recirculation loop:

a) The two recirculation loops have a flow imbalance of 15% or more when the pumps are operated at the same speed.

See Discussion of Changes for ITS 3.4.1, "Recirculation Loops Operating"

M2

b) The indicated value of core flow rate varies from the value derived from loop flow measurements by more than 10%.

b. c) ~~During two loop operation,~~ the diffuser to lower plenum differential pressure reading on an individual jet pump varies from the ~~mean of all jet pump differential pressures by more~~ less than ~~10%~~ 20%.

the established pattern

A3 L5 A2

d) ~~During single loop operation, diffuser to lower plenum differential pressure reading on an individual jet pump in the operating loop varies from the mean of all jet pump differential pressures in the operating loop by more than 10%.~~

M2

2. ~~Additionally when operating one recirculation pump, the diffuser to lower plenum differential pressure shall be checked daily and the differential pressure of any jet pump in the idle loop shall not very by more than 10% from established pattern.~~

3. The baseline data required to evaluate the conditions in specification 4.6.E.1 and 4.6.E.2 will be obtained each operating cycle.

R2

page 1 of 2

A1 3.4 REACTOR COOLANT SYSTEM (RCS)

--- 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

A1

~~LIMITING CONDITION FOR OPERATION~~

4.2 3.~~6~~ ~~E~~ Jet Pumps

A1

~~3.~~ APPLICABILITY ~~Whenever the reactor is in the startup or run modes,~~ MODES 1 and 2

LCO 3.4.2 all jet pumps shall be operable.

ACTION A If it is determined that a jet pump is inoperable, an orderly shutdown shall be initiated and the reactor shall be in a ~~Cold Shutdown within 24 hours~~. MODE 3 in 12 hours

L4

R1

2. Flow indications from each of the 20 jet pumps during two loop operation or 10 jet pumps during single loop operation shall be verified prior to initiation of reactor startup from a cold shutdown condition.

3. The indicated core flow is the sum of the flow indication from each of the 20 jet pumps. Flow indication from no more than one jet pump shall be unavailable during two loop operation. If two or more jet pump flow indication failures occur during two loop operation, an orderly shutdown shall be initiated within 12 hours and the reactor shall be in cold shutdown condition within the following 24 hours.

L3

4. During single loop operation, no jet pump flow indication failures in the operating loop are permissible. If a jet pump flow indication failure occurs during single loop operation, an orderly shutdown shall be initiated within 12 hours and the reactor shall be in cold shutdown condition within the following 24 hours.

M2

a. Recirculation pump flow to speed ratio differs by ≤ 5% from established patterns, and jet pump loop flow to recirculation pump speed ratio differs by ≤ 5% from established patterns.

c. Each jet pump flow differs by ≤ 10% from established patterns.

~~SURVEILLANCE REQUIREMENTS~~

~~4.6.~~E Jet ~~Pumps~~ SR 3.4.2.1

A2

~~1.~~ ~~Whenever there is recirculation flow with the reactor in the startup or run modes, jet pump operability shall be checked daily by verifying that the following conditions do not occur simultaneously:~~

verify at least one of the following criteria (a, b, or c) is satisfied for each operating recirc loop:

B

~~a)~~ ~~The two recirculation loops have a flow imbalance of 15% or more when the pumps are operated at the same speed.~~

see Discussion of Change for ITS 3.4.1, Recirculation Loops Operating

M2

~~b)~~ ~~The indicated value of core flow rate varies from the value derived from loop flow measurements by more than 10%.~~

b.

~~c)~~ ~~During two loop operation,~~ the diffuser to lower plenum differential pressure reading on an individual jet pump varies from the ~~mean of all jet pump differential pressures~~ the established pattern by ~~more~~ less than ~~10%~~ 20%.

A3

L2

A2

~~d)~~ ~~During single loop operation, diffuser to lower plenum differential pressure reading on an individual jet pump in the operating loop varies from the mean of all jet pump differential pressures in the operating loop by more then 10%.~~

M1

~~2.~~ ~~Additionally when operating one recirculation pump, the diffuser to lower plenum differential pressure shall be checked daily and the differential pressure of any jet pump in the idle loop shall not vary by more then 10% from established pattern.~~

~~3.~~ ~~The baseline data required to evaluate the conditions in specification 4.6.E.1 and 4.6.E.2 will be obtained each operating cycle.~~

R2

Page 2 of 2

DISCUSSION OF CHANGES
ITS 3.4.2: JET PUMPS

ADMINISTRATIVE CHANGES

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 The wording of the Surveillance Requirement was changed to require the verification that one of the following criteria is met rather than verifying that none of the conditions exist simultaneously. This is consistent with NUREG-1433 which attempts to phrase everything in a positive manner. Due to the change in the phrasing of the Surveillance "more than" was changed to "less than" in criteria b.

A_3 The variance of the diffuser-to-lower plenum differential pressure reading on an individual jet pump will now be taken from the established pattern rather than from the mean of all jet pump differential pressures. This change is in accordance with the recommendations of SIL-330 and NUREG/CR-3052. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 Not used. 3

M_2 This change adds two requirements to the Surveillance to detect significant degradation in jet pump performance that precedes jet pump failure. The first requirement added would detect a change in the relationship between pump speed, and pump flow and loop flow (difference > 5%). A change in the relationship indicates a plug flow restriction, loss in pump hydraulic performance leakage, or new

TECHNICAL CHANGES - MORE RESTRICTIVE

M_2 (cont'd) flow path between the recirculation pump discharge and jet pump nozzle. The second requirement added monitors the jet pump flow versus established patterns. Any deviations > 10% from normal are considered indicative of potential problem in the recirculation drive flow or jet pump system. These two added requirements to the Surveillance help to detect significant degradation in jet pump performance that precedes jet pump failure. Requirements added to Surveillance Requirements constitute a more restrictive change. This change is consistent with NUREG-1433.

SIL-330 provides two alternate testing criteria (thus the deletion of current Surveillance 4.6.E.1.b). One method uses easy to perform surveillances with strict limits to initially screen jet pump Operability (the proposed changes above). If these limits are not met, another set of Surveillances exists (current Technical Specifications). Revising the Surveillances to include the stricter limits reflects a more restrictive change.

TECHNICAL CHANGES - RELOCATIONS

R_1 This change relocates specific information from Specifications 3.6.E.2, 3.6.E.3, and 3.6.E.4 related to systems (e.g. "indicated core flow is the sum of the flow indication from each of the 20 jet pumps") to a licensee controlled document. This information will not be changed without a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_2 This change relocates the requirement to obtain baseline data required to evaluate jet pump Operability. This requirement could be relocated to a licensee controlled document (i.e. the startup testing program) for two loop operation and a single loop procedure for single loop operation. Also, in order to have established patterns a baseline must exist. Any changes to these requirements will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

DISCUSSION OF CHANGES
ITS 3.4.2: JET PUMPS

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 This change adds two notes to the Surveillance which relax the Surveillance Frequency to allow a 4 hour delay in performance of the Surveillance after the associated recirculation loop is in operation and an exemption to the performance of the Surveillance until 24 hours after the plant reaches 25% RTP. The first note allows the Surveillance not to be performed until 4 hours after the associated recirculation loop is in operation, because these checks can only be performed during jet pump operation. The four hours is an acceptable time to establish conditions appropriate for data collection and evaluation. The second note allows the Surveillance to not be performed when THERMAL POWER is ≤ 25% of RTP. During low flow conditions, jet pump noise approaches the threshold response of the associated flow instrumentation and precludes the collection of the repeatable and meaningful data. Currently, the Surveillance is required whenever there is recirculation flow and the reactor is in the startup or run Modes.

L_2 The proposed change adjusts the surveillance acceptance criteria from 10% to 20% for individual jet pump diffuser-to-lower plenum differential pressure variations from the established pattern. This is located in the Surveillance that verifies the Operability of the jet pumps. This change corrects an error in Technical Specifications. This change is consistent with the recommendations of SIL-330 (GE Service Information Letter number 330) and NUREG/CR-3052 (Closeout of IE Bulletin 80-07: BWR Jet Pump Assembly Failure). SIL-330 specifies a 10% criteria for individual jet pump flow distribution. When measured by jet pump diffuser-to-lower plenum differential pressure, the equivalent limit is 20% because of the relationship between flow and delta-P. Since PBAPS Units 2 and 3 utilize the diffuser-to-lower plenum differential pressure measurement, the variance allowed should have been 20% as was recommended in SIL-330 and NUREG/CR-3052. Since the value is being changed from 10% to 20%, it is considered a relaxation from existing requirements although the change corrects an error. Therefore, this change constitutes a less restrictive change. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L_3 This change deletes the current shutdown requirement associated with jet pump flow indication. Currently, when required jet pump flow indication is lost, an orderly shutdown must be initiated in 12 hours and the reactor is required to be in Cold Shutdown within the following 24 hours (since Mode 3 is the non-applicable mode, then 24 hours is allowed to reach Mode 3; see discussion of change M_1 for ITS 3.4.2). The proposed Specification implicitly requires the jet pump flow indication to be Operable only for the performance of the Surveillance Requirement. If the flow indication is inoperable when the surveillance is required to be performed, the jet pump would be declared inoperable and the appropriate actions would be followed. Since the proposed jet pump surveillance requirement is required to be performed every 24 hours (the 25% extension per SR 3.0.2 can be applied) and the Required Actions require the reactor to be in Mode 3 within 12 hours, the maximum difference in the current Specification and the proposed specification is 6 hours. As a result, the proposed specification effectively allows a maximum of an additional 6 hours (which is the 25% extension) to reach a non-applicable Mode if a required core flow indicator is inoperable. Depending on when the failure occurs, 6 hours is the maximum increase over the current Specifications (failure occurring immediately after the Surveillance is performed). The following table provides the details of the calculation of the 6 hour period:

Current Tech Specs	Proposed Tech Specs
Time 0 hours - Jet Pump Indication Fails - 12 hr AOT Begins	Time 0 hours - Jet Pump Indication Fails (Immediately After SR)
Time 12 hours- 12 hr AOT Expires - 24 hr AOT Begins to MODE 3 (per 3.0.A; see M_1)	Time 30 hours- (24 hrs x 1.25) SR due; Flow Indication Inop - 12 hr AOT to MODE 3 Begins
Time 36 hours- 24 hr AOT Expires Plant in MODE 3	Time 42 hours- 12 hour AOT Expires Plant in MODE 3

TECHNICAL CHANGES - LESS RESTRICTIVE

L_3 (cont'd) As depicted above, 42 hours is the maximum time that would be allowed if a required jet pump flow indicator is inoperable. Currently a maximum of 36 hours is allowed.

Jet pump flow indication Operability does not directly impact jet pump Operability. Jet pump flow indication is only required to perform the jet pump Surveillance (SR 3.4.2.1). SR 3.4.2.1 verifies jet pump Operability and has a frequency of every 24 hours. The 24 hours Frequency plus the 25% extension has been shown by operating experience to be timely for detecting jet pump degradation and is consistent with the Surveillance Frequency for recirculation loop Operability verification. The most common outcome of the performance of a surveillance is the successful demonstration that the acceptance criteria are satisfied. This change is consistent with NUREG-1433.

L_4 Current Technical Specification (CTS) 3.6.E.1 states that if it is determined that a jet pump is inoperable, an orderly shutdown shall be initiated and the reactor shall be in a Cold Shutdown within 24 hours. ITS 3.4.2, Jet Pumps, for the Condition of an inoperable jet pump, requires the reactor to be placed in MODE 3 (Hot Shutdown) within 12 hours. Since the ITS shutdown action does not require placing the unit in MODE 4 (Cold Shutdown), the change to the shutdown action has been categorized as a less restrictive change. The change is considered acceptable since the Applicability of CTS 3.6.E, Jet Pumps, is whenever the reactor is in the startup or run modes (mode switch position as defined in CTS 1.0, Definitions). The Applicability of ITS 3.4.2 is MODES 1 and 2, which are equivalent to the run and startup modes, respectively, of the CTS. In the event of a failure to comply with requirements of the LCO, the reactor must be placed in a non-applicable MODE or condition. The ITS change reflects placing the reactor in the first available non-applicable MODE or condition. This change also achieves consistency with CTS 3.0.A. CTS 3.0.A states "Limiting Conditions for Operation and action requirements are applicable during the operational conditions and other states specified for each specification." Since the applicability of the CTS jet pumps limiting condition for operation and action is with the mode switch in startup or run, placing the mode switch in shutdown (MODE 3 in the ITS) results in exiting the jet pump condition of applicability. As a result, any further reduction in MODE or condition (to Cold Shutdown) is not required per CTS 3.0.A. In addition, not requiring the reactor to be placed in Cold Shutdown (mode switch in shutdown and average reactor coolant temperature $\leq$ 212°F) reduces the potential for an unnecessary shutdown transient and the resultant thermal effects on plant equipment.

DISCUSSION OF CHANGES
ITS 3.4.3: SAFETY RELIEF VALVES (SRVs) AND SAFETY VALVES (SVs)

<u>ADMINISTRATIVE CHANGES</u>

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 The one time extension for Unit 2 to allow continued operation (past the 30 day allowed outage time) with one of thirteen SRVs and SVs inoperable will be deleted since the one time extension has expired.

<u>TECHNICAL CHANGES - MORE RESTRICTIVE</u>

M_1 Currently each SRV must be verified to open when manually actuated with reactor steam dome pressure ≥ 100 psig. The proposed change will replace the requirement for reactor steam dome pressure to be ≥ 100 psig with a note that states that the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. This change applies a time limit for performance of the Surveillance which constitutes a more restrictive change.

<u>TECHNICAL CHANGES - RELOCATIONS</u>

R_1 The requirement to disassemble and inspect one SRV every 24 months will be relocated. Maintenance related activities are being relocated out of Technical Specifications. Therefore, this requirement is being relocated into plant procedures. Any changes to this requirement will require a 10 CFR 50.59 evaluation. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS (continued)

R_2 The SRV bellows instrumentation does not necessarily relate directly to the respective system Operability. In general, the BWR Standard Technical Specifications, NUREG-1433, do not specify indication only equipment to be Operable to support Operability of a system or component. Control of the availability of, and necessary compensatory activities if not available, for indications, monitoring instruments, and alarms are addressed by plant operational procedures and policies. Therefore this instrumentation, along with the supporting Surveillances are removed from the Technical Specifications. Any changes to this requirement will require a 10 CFR 50.59 evaluation. This change is consistent with NUREG-1433.

R_3 The specific instruction on how to verify that the SRV is manually opened is being relocated. Specific instructions on how to perform surveillances are being relocated out of Technical Specifications. Therefore, this requirement will be relocated into the Technical Specification Bases and plant procedures. Any changes to this requirement will require a 10 CFR 50.59 evaluation. This change is consistent with NUREG-1433.

R_4 The requirement to perform an inspection for leakage of the accumulators and air piping for the SRVs once per operating cycle will be relocated to plant procedures. Any changes to this requirement will require a 10 CFR 50.59 evaluation. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 This proposed change reduces the number of SRVs and SVs to be Operable from 13 to 11. The current requirement requires all 13 SRVs and SVs to be Operable. It specifies an allowed outage time of 30 days if one SRV is inoperable and 7 days if two are inoperable. The proposed Specification requires 11 SRVs and SVs to be Operable because the analysis for the worst case accident (closure of all MSIVs with failure of the direct scram associated with MSIV position) shows 11 SRVs and SVs are sufficient to maintain reactor pressure below the ASME Code limit of 110% of design pressure. This change will eliminate the current allowed outage times for one or two SRVs out of service when 13 SRVs and SVs are required to be Operable. The proposed change will require with one or more required SRVs or SVs inoperable that the plant be shutdown since this condition represents a loss of function. This is consistent with the current requirement when more than two SRVs are inoperable.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L_2 This change relaxes the shutdown requirement if the Required Actions and the associated Completion Times are not met. The change requires the reactor to be brought to Mode 3 in 12 hours and Mode 4 in 36 hours. The current requirements require reactor pressure to be reduced to below atmospheric pressure in 24 hours (equivalent to cold shutdown, i.e., when the reactor can be vented). The proposed Completion Times are based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. The proposed shutdown requirement brings the plant to a Mode 4 which is below the mode of applicability. 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. The current requirements would require the plant to be depressurized to a condition which is beyond the accident assumptions of when the SRVs and SVs are required to mitigate credible accidents and transients.

DISCUSSION OF CHANGES
ITS 3.4.4: RCS OPERATIONAL LEAKAGE

ADMINISTRATIVE CHANGES

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 Proposed LCO 3.4.4, RCS Operational Leakage, includes an additional requirement that no pressure boundary leakage is allowed because this condition is 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 considered pressure boundary leakage. In addition, shutdown Actions have been provided for the Condition of pressure boundary leakage. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS

None

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 Existing Specification 3.6.C.4 requires that the reactor be in Hot Shutdown within 12 hours and Cold Shutdown within the following 24 hours if the specified requirements for RCS leakage are not being met. Proposed LCO 3.4.4, RCS Operational Leakage, Condition A and Condition B (Required Action B.1), provides an additional 4 hours to

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 (cont'd) allow the operators to reduce the leakage (or leakage increase) to within acceptable limits before a reactor shutdown must be initiated. This additional 4 hours is acceptable because the leakage limits are significantly below the leakage that would constitute a critical crack size. The critical crack size is a crack large enough that it is indicative of crack instability. This change is consistent with NUREG-1433.

L_2 Proposed LCO 3.4.4, RCS Operational Leakage, will add an alternative to the existing requirement in Specifications 3.6.C.1 and 3.6.C.4 that a reactor shutdown be initiated if unidentified leakage increases at a rate of more than 2 gpm within a 24 hour period. Under proposed Required Action B.2 unidentified leakage that increases at a rate of more than 2 gpm within a 24 hour period will not require initiation of a reactor shutdown if it can be determined within 4 hours that the source of the unidentified leakage is not service sensitive type 304 and type 316 austenitic stainless steel piping that is subject to high stress or that contains relatively stagnant or intermittent flow fluids. This alternative Required Action is acceptable because the low limit on the rate of increase of unidentified leakage was established as a method for early identification of Intergranular Stress Corrosion Cracking (IGSCC) in type 304 and type 316 austenitic stainless steel piping. IGSCC produces tight cracks and the small flow increase limit is capable of providing an early warning of such deterioration. Verification that the source of leakage is not type 304 and type 316 austenitic stainless steel eliminates IGSCC as a cause of a leak. This significantly reduces concerns about crack instability and the rapid failure in the RCS boundary. Also, the unidentified LEAKAGE limit is still being maintained and will continue to limit the maximum unidentified LEAKAGE allowed. This change is consistent with NUREG-1433.

DISCUSSION OF CHANGES
ITS 3.4.5: LEAKAGE DETECTION INSTRUMENTATION

ADMINISTRATIVE CHANGES

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 Proposed LCO 3.4.5, Condition B, has Required Actions modified by a Note that states the provisions of LCO 3.0.4 are not applicable. As a result, a Mode change is allowed when both the particulate and gaseous primary containment atmospheric monitoring channels are inoperable. This allowance is provided because, in this Condition, the primary containment (drywell) sump collection and flow monitoring system will be available to monitor RCS leakage and the compensatory actions for the inoperable system will provide additional indication of RCS leakage. This is an administrative change because existing PBAPS Technical Specifications do not have a requirement that prohibits entry into a Mode or condition when an LCO required by that Mode or condition is not satisfied. Therefore, existing Technical Specifications already allow the actions being permitted by the note being added. The change is consistent with NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 Existing Specifications 3.6.C.2 and 3.6.C.3 require that the drywell sump collection and flow monitoring system and the drywell atmosphere radioactivity monitor be Operable "during reactor power operation." Proposed LCO 3.4.5, RCS Leakage Detection Instrumentation, is applicable in Modes 1, 2, and 3. Proposed LCO 3.4.5, RCS Leakage Detection Instrumentation, governs all of the

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 (cont'd) instrumentation needed to support implementation of proposed LCO 3.4.4, RCS Operational Leakage. Therefore, this more restrictive change is being made so that the Applicability of proposed LCO 3.4.5 will match the Applicability of proposed LCO 3.4.4.

M_2 Existing Specification 3.6.C.3 allows continued operation with the drywell atmosphere radioactivity monitor inoperable for "up to 30 days provided grab samples of the containment atmosphere are obtained and analyzed at least once every 24 hours." Proposed LCO 3.4.5, Required Action B.1, requires that grab samples be obtained every 12 hours whenever the drywell atmosphere radioactivity monitor is inoperable. With both gaseous and particulate primary containment atmospheric monitoring channels inoperable, grab samples of the primary containment atmosphere must be taken and analyzed to provide periodic leakage information. The 12 hour interval provides periodic information that is considered adequate to detect leakage provided at least one other form of leakage detection is available. This change is consistent with NUREG-1433.

M_3 Proposed LCO 3.4.5, ACTION D, adds an explicit requirement to enter proposed LCO 3.0.3 if all required leakage detection systems are inoperable. This is a more restrictive change because existing Specification 3.6.C.2, governing the drywell sump collection and flow monitoring system, and Specification 3.6.C.3, governing the drywell atmosphere radioactivity monitor, are independent and existing Technical Specifications will allow continued operation even if actions statements have been entered for both Specification 3.6.C.2 and Specification 3.6.C.3, (i.e. no operable leakage detection systems). This change is consistent with NUREG-1433.

M_4 Existing Specification 4.2.E and associated Table 4.2.E specifies the surveillance frequency of once/day for an Instrument Check for the Drywell Atmosphere Radiation Monitor. The frequency for an Instrument Check for the Drywell Atmosphere Radiation Monitor is being increased to every 12 hours to be consistent with NUREG-1433 and is more restrictive.

TECHNICAL CHANGES - RELOCATIONS

R_1 Existing Specification 4.6.C.1 identifies that RCS leakage shall be determined "by the primary containment (Drywell) sump collection and flow monitoring system." Details of the methods for performing surveillance are being relocated to plant procedures and will be controlled in accordance with 10 CFR 50.59.

R_2 Existing Specification 4.6.C.2 requires that drywell atmosphere radioactivity levels shall be monitored and recorded at least once per day. The details relating to recording the readings has been relocated to the procedures. The CHANNEL CHECK requirement (monitoring) is still maintained as SR 3.4.5.1. Changes to the procedures will be controlled in accordance with 10 CFR 50.59.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 These requirements have been deleted. An instrument check would not consistently demonstrate operability since normally the instruments could not be compared to any other instruments, and their reading could be anywhere on scale. Thus, observing the meter would provide no valid information as to whether the instrument was OPERABLE. The CHANNEL FUNCTIONAL TEST requirement is the best indicator of OPERABILITY while operating, and this requirement is being maintained. This is also consistent with NUREG-1433.

DISCUSSION OF CHANGES
ITS 3.4.6: SPECIFIC ACTIVITY

ADMINISTRATIVE CHANGES

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 Proposed LCO 3.4.6, Condition A, will be 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 reactor coolant specific activity is > 0.2 microcuries per gram but ≤ 4.0 microcuries per gram. This allowance is provided because of the significant conservatism incorporated into the specific activity limit, the low probability of an event for which specific activity is limiting, and the ability to restore specific activity transients while the plant remains at, or proceeds to power operation. This is an administrative change because existing PBAPS Technical Specifications do not have a requirement that prohibits entry into a Mode or condition when an LCO required by that Mode or condition is not satisfied. Therefore, existing Technical Specifications already allow the actions permitted by the note being added.

A_3 Existing Specification 3.6.B.1 requires that 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, the reactor must be shutdown and all the main steam lines must be isolated within 12 hours. Proposed LCO 3.4.6, Condition B, allows the alternative of being in Mode 3 within 12 hours and Mode 4 within 36 hours under the same conditions. 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. This change is considered administrative because existing LCO 3.0.C would require that the reactor be placed in Mode 4 within 36 hours if the requirements in existing Specification 3.6.B.1 could not be met. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 Existing Specification 3.6.B.1 is applicable "whenever the reactor is critical." Proposed LCO 3.4.6, RCS Specific Activity, is applicable in Mode 1, and Modes 2 and 3 with any main steam line not isolated. The Applicability for RCS specific activity requirements is based on limiting the consequences of a main steam line break outside containment. In Modes 2 and 3 with the MSIVs closed, RCS specific activity limits are not necessary since the main steam line break outside containment would not result in a release of reactor coolant outside containment. In Modes 4 and 5, no limits are required since the reactor is not pressurized and the potential for leakage is reduced. This change in Applicability is consistent with NUREG-1433.

M_2 Existing Specification 4.6.B.1 requires sampling reactor coolant chemistry for specific activity "during equilibrium power operation." Proposed SR 3.4.6.1, which contains the proposed requirements for sampling reactor coolant chemistry for specific activity, is modified by a note that requires this Surveillance to be performed only in Mode 1. This change is slightly more restrictive because sampling will be required whenever the reactor is in Mode 1 and not just when equilibrium conditions have been established. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS

R_1 Existing Specification 4.6.B.1 contains requirements for reactor coolant and offgas system sampling during startup, following significant power level changes, and following significant changes in offgas radiation levels. The results of any of these samples are intended to determine if RCS specific activity is exceeding specified limits. Experience has determined that the weekly sampling required by proposed SR 3.4.6.1 and requirements for monitoring main steam line and offgas radiation levels is sufficient to ensure RCS specific activity levels are not exceeded. Therefore, RCS specific activity requirements for sampling stack gas, offgas and main steam line are being relocated to plant procedures and will be controlled in accordance with 10 CFR 50.59. In addition, the criteria for when specific activity has been returned to limits (until two successive samples indicate a decreasing trend below the limit with at least 3 consecutive samples being taken) has been relocated to plant procedures and will be controlled by 10 CFR 50.59. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 Existing Specification 4.6.B.1 limits the amount of time to 800 hours in any consecutive 12 month period that the reactor may be operated with reactor coolant specific activity Dose Equivalent I-131 greater than 0.2 μCi/gm. In accordance with the recommendations in Generic Letter 85-19, Reporting Requirements on Primary Coolant Iodine Spikes, proposed LCO 3.4.6 will not include the 800 hour limit. Generic Letter 85-19 states that the 800 hour limit is not necessary because reactor fuel has improved significantly since this requirement was established, and that proper fuel management by licensees and existing reporting requirements for fuel failures will preclude ever approaching this limit of operating with specific activity > 0.2 μCi/gm for more than 800 hours. This change is consistent with NUREG-1433.

DISCUSSION OF CHANGES
ITS 3.4.7: RHR SHUTDOWN COOLING SYSTEM - HOT SHUTDOWN
ITS 3.4.8: RHR SHUTDOWN COOLING SYSTEM - COLD SHUTDOWN

ADMINISTRATIVE CHANGES

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 Technical Specifications will be added for the RHR shutdown cooling (SDC) subsystems in Modes 3 and 4. In Modes 3 and 4, the RHR shutdown cooling subsystem is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR shutdown cooling subsystem does not meet any of the specific deterministic criterion of the NRC Policy Statement; however, it was identified as an important contributor to risk reduction. The addition of new Specifications is a more restrictive change necessary to achieve consistency with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS

None

TECHNICAL CHANGES - LESS RESTRICTIVE

None

DISCUSSION OF CHANGES
ITS 3.4.7: RHR SHUTDOWN COOLING SYSTEM - HOT SHUTDOWN
ITS 3.4.8: RHR SHUTDOWN COOLING SYSTEM - COLD SHUTDOWN

ADMINISTRATIVE CHANGES

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 Technical Specifications will be added for the RHR shutdown cooling (SDC) subsystems in Modes 3 and 4. In Modes 3 and 4, the RHR shutdown cooling subsystem is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR shutdown cooling subsystem does not meet any of the specific deterministic criterion of the NRC Policy Statement; however, it was identified as an important contributor to risk reduction. The addition of new Specifications is a more restrictive change necessary to achieve consistency with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS

None

TECHNICAL CHANGES - LESS RESTRICTIVE

None

Specification 3.4.9

A1

LIMITING CONDITIONS FOR OPERATION

~~3.6 PRIMARY SYSTEM BOUNDARY~~

~~Applicability:~~

~~Applies to the operating status of the reactor coolant system.~~

~~Objective:~~

~~To assure the integrity and safe operation of the reactor coolant system.~~

~~Specification:~~

A1 3.4.9 RCS Pressure and Temperature (P/T) Limits

~~A. Thermal and Pressurization Limitations~~

APPLICABILITY: At all times A1

A1 LCO 3.4.9 ~~1.~~ The average rate of reactor coolant temperature change during normal heatup or cooldown shall not exceed 100° F increase (or decrease) in any one-hour period. SR 3.4.9.1.b A1

A1 LCO 3.4.9 ~~2.~~ The reactor vessel shall not be pressurized for inservice hydrostatic testing above the pressure allowable for a given temperature by Figure ~~3.6.1.~~ 3.4.9-1 A1. SR 3.4.9.1.a A1

A1 LCO 3.4.9 The reactor vessel shall not be pressurized during heatup by non-nuclear means, during cooldown following nuclear shut down or during low level physics tests above the pressure allowable by Figure ~~3.6.2~~ 3.4.9-2 A1, based on the temperatures recorded under 4.6.A. SR 3.4.9.1.a A1

A1 LCO 3.4.9 The reactor vessel shall not be pressurized during operation with a critical core above the pressure allowable by Figure ~~3.6.3~~ 3.4.9-3 A1, based on the temperatures recorded under 4.6.A. SR 3.4.9.2 A1

SURVEILLANCE REQUIREMENTS

~~4.6 PRIMARY SYSTEM BOUNDARY~~

~~Applicability:~~

~~Applies to the periodic examination and testing requirements for the reactor coolant system.~~

~~Objective:~~

~~To determine the condition of the reactor coolant system and the operation of the safety devices related to it.~~

~~Specification:~~

A1 ~~A. Thermal and Pressurization Limitations~~

SR 3.4.9.1 ~~1.~~ During heatups and cool-downs the following temperatures shall be permanently logged at least every ~~15~~ 30 L1 minutes ~~until the difference between any 2 readings taken over a 45 minute period is less than 5° F.~~ R2 (SR 3.4.9.1 Note)

~~(a) Bottom head drain~~ R3

~~(b) Recirculation loop A and B.~~

A1 SR 3.4.9.1 ~~2.~~ Reactor vessel temperature and reactor coolant pressure shall be permanently logged at least every ~~30~~ 30 L1 minutes ~~whenever the shell temperature is below 220° F and the reactor vessel is not vented.~~ M1

~~Test specimens of the reactor vessel base, weld and heat affected zone metal were installed in the reactor vessel adjacent to the vessel wall at the core midplane level. The specimens and sample program shall conform to ASTM E 185-66 to the degree discussed in the FSAR.~~ R4

SR 3.4.9.2 → M2

Specification 3.4.9

~~LIMITING CONDITIONS FOR OPERATION~~

~~3.6.A Thermal and Pressurization Limitations (Cont'd)~~

A1

~~SURVEILLANCE REQUIREMENTS~~

~~4.6.A Thermal and Pressurization Limitations (Cont'd)~~

~~Selected surveillance specimens shall be removed and tested in accordance with 10 CFR 50, Appendix H, to experimently verify or adjust the calculated values of integrated neutron flux and irradiation embrittlement that are used to determine the RT_{NDT} for Figures 3.6.1, 3.6.2 and 3.6.3, and the figures shall be updated based on the results.~~ A2

A1 LCO 3.4.9 2. The reactor vessel head bolting studs shall not be under tension unless the temperatures of the closure flanges and adjacent vessel and head materials are greater than 70° F. A1 SR 3.4.9.5 SR 3.4.9.6 SR 3.4.9.7

A1 2. SR 3.4.9.5 SR 3.4.9.6 SR 3.4.9.7 and SRs Notes When the reactor vessel head bolting studs are tensioned and the reactor is in a Cold Condition, the reactor vessel shell temperature immediately below the head flange shall be permanently recorded.

A1 LCO 3.4.9 4. The pump in an idle recirculation loop shall not be started unless the temperatures of the coolant within the idle and operating recirculation loops are within 50° F of each other. A1 SR 3.4.9.4

A1 4. SR 3.4.9.4 and Note A3 Prior to and during startup of an idle recirculation loop, the temperature of the reactor coolant in the operating and idle loops shall be permanently logged.

A1 LCO 3.4.9 5. The reactor recirculation pumps shall not be started unless the coolant temperatures between the dome and the bottom head drain are within 145° F. SR 3.4.9.3 A1

A1 5. SR 3.4.9.3 and Note A3 Prior to starting a recirculation pump, the reactor coolant temperatures in the dome and in the bottom head drain shall be compared and permanently logged.

ACTIONS A, B, and C → M3

Frequencies for SR 3.4.9.5, SR 3.4.9.6, and SR 3.4.9.7 M4

JUN 27 1991

Specification 3.4.9

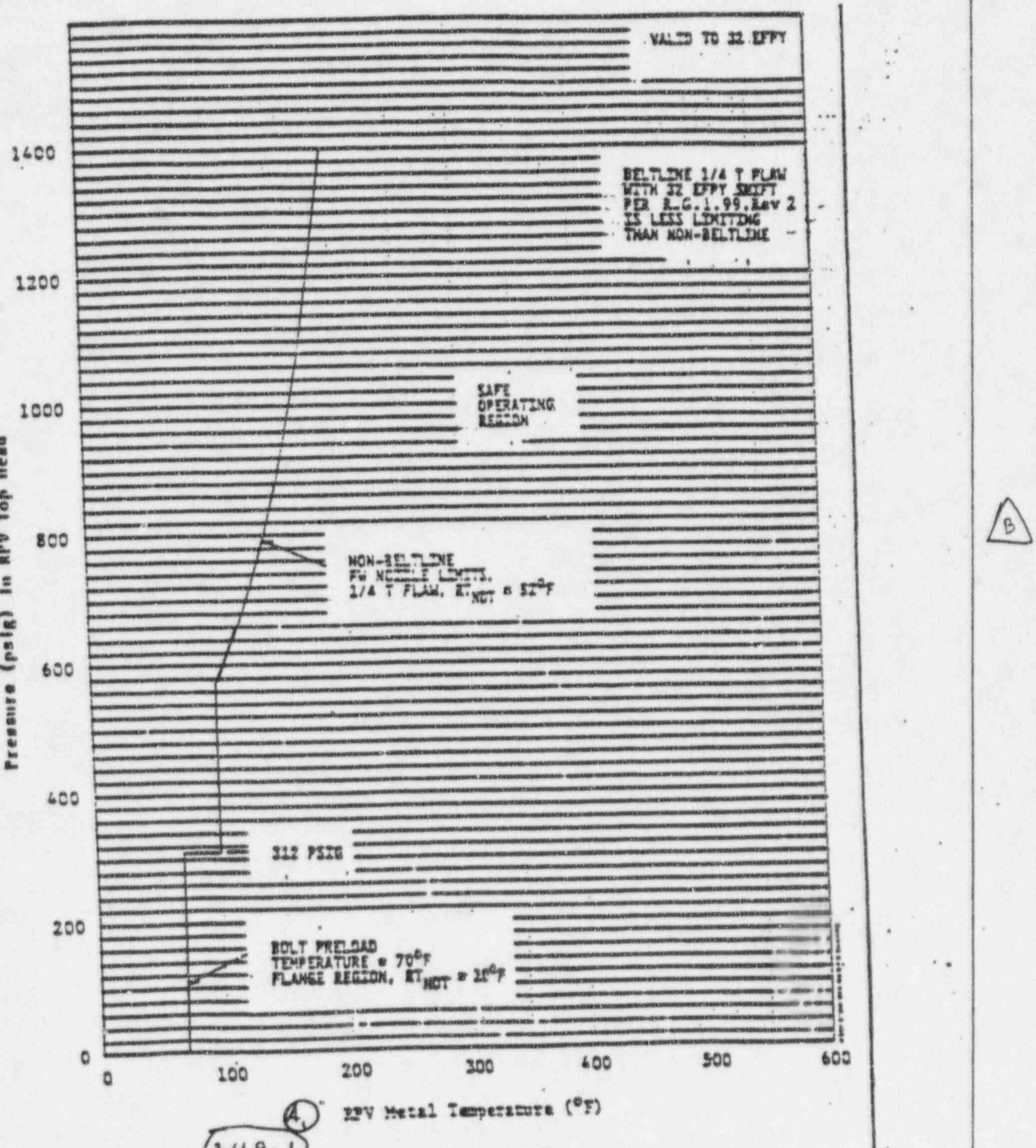
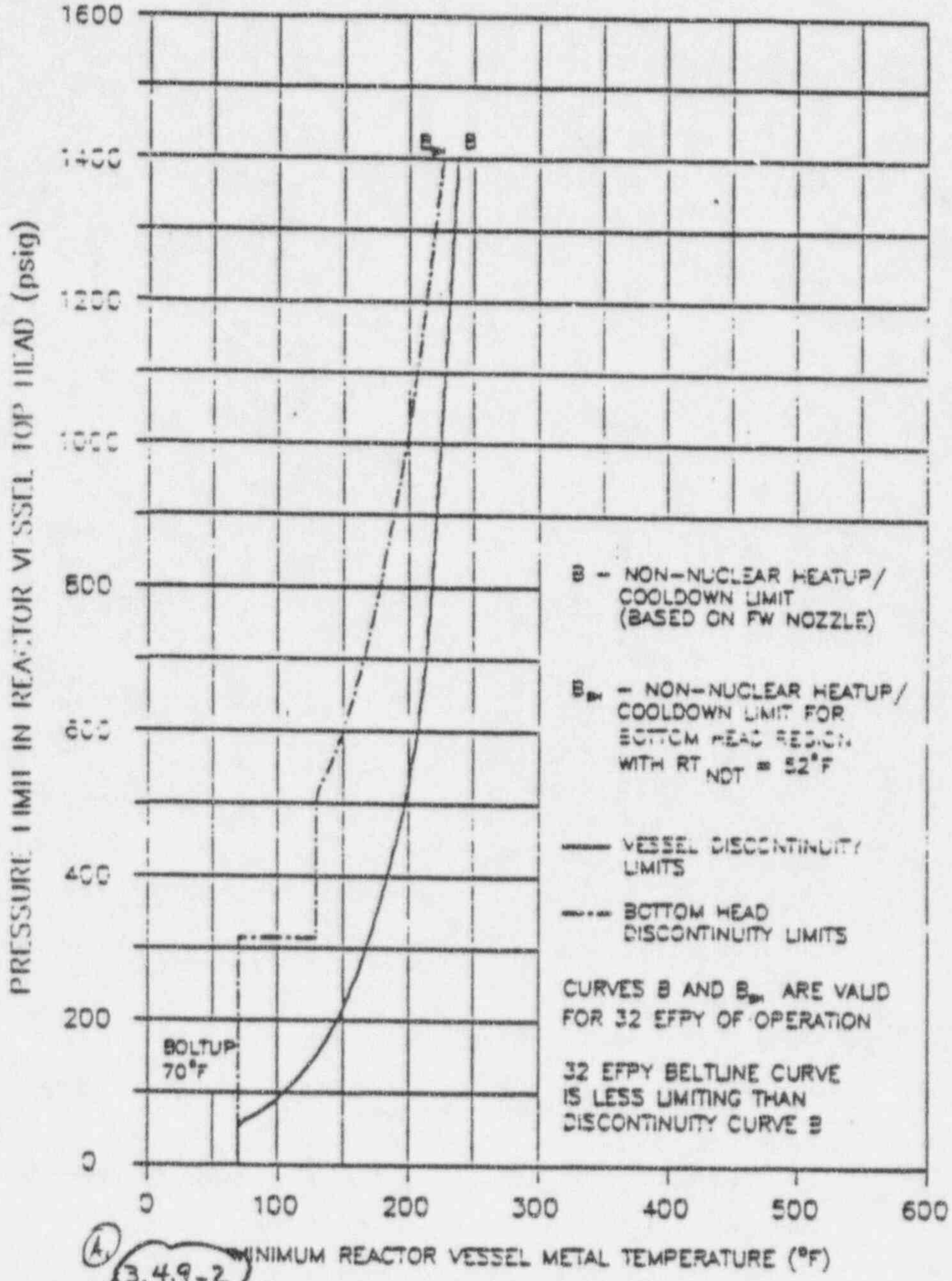


Figure ~~3.6.1~~ 3.4.9-1 Peach Bottom 2 Minimum Temperature for Pressure Tests Such as Required by Section XI

Specification 3.4.9

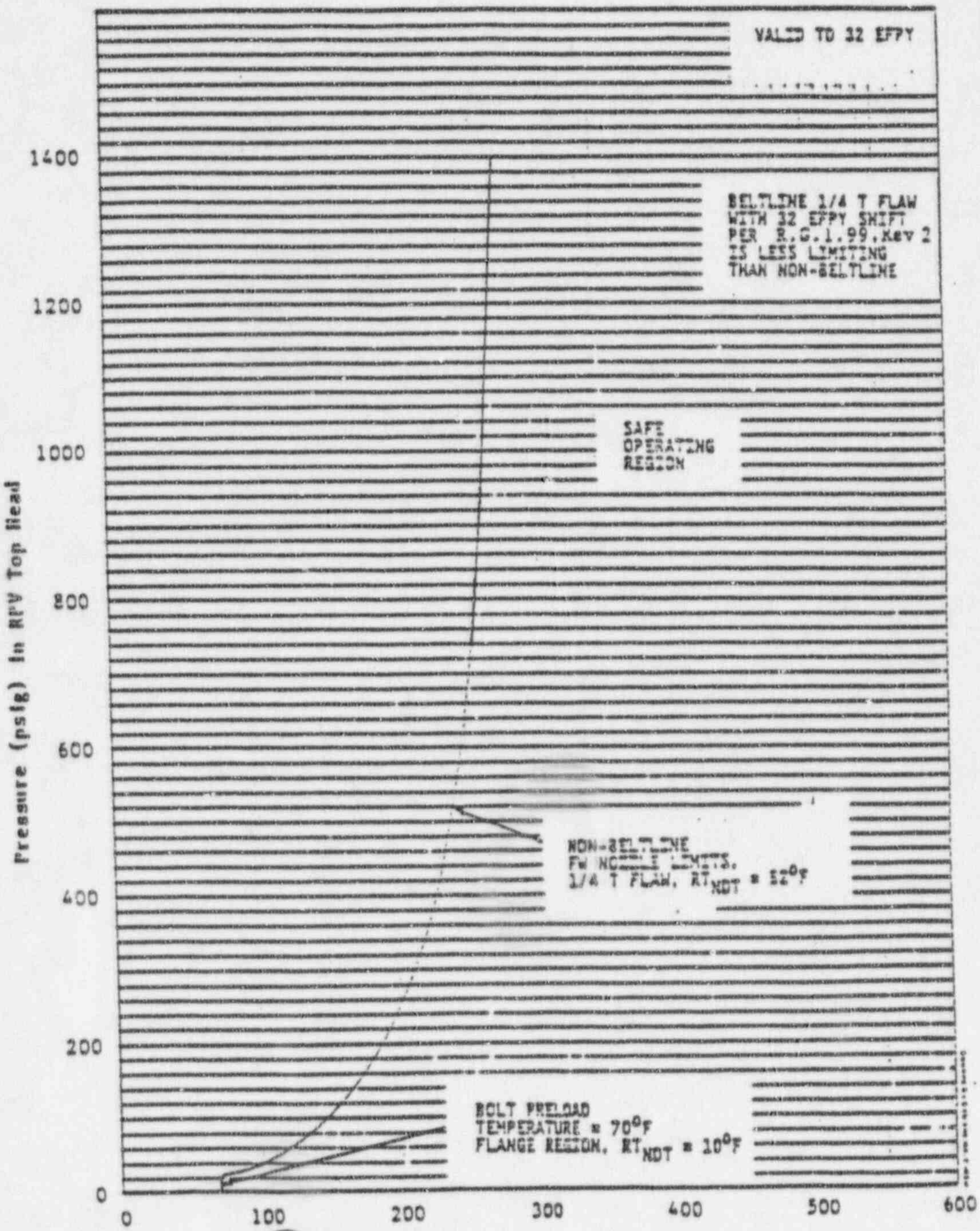


A

Figure 3.4.9-2 ~~3.6.2~~ Peach Bottom 2 Minimum Temperature for Mechanical Heatup or Cooldown Following Nuclear Shutdown

B

Specification 3.4.9



3.4.9-3

Figure ~~3.6.5~~ Peach Bottom 2 ~~Minimum~~ Temperature for Core Operation (Criticality)

Specification 3.4.9

A1

~~LIMITING CONDITIONS FOR OPERATION~~

~~3.6 PRIMARY SYSTEM BOUNDARY~~

~~Applicability:~~

~~Applies to the operating status of the reactor coolant system.~~

~~Objective:~~

~~To assure the integrity and safe operation of the reactor coolant system.~~

~~Specification:~~

A1 3.4.9 RCS Pressure and Temperature (P/T) Limits

~~A. Thermal and Pressurization Limitations~~

APPLICABILITY: At all times A1

A1 LCO 3.4.9 ~~1.~~ The average rate of reactor coolant temperature change during normal heatup or cooldown shall not exceed 100° F increase (or decrease) in any one-hour period. A1 SR 3.4.9.1.b

A1 LCO 3.4.9 ~~2.~~ The reactor vessel shall not be pressurized for inservice hydrostatic testing above the pressure allowable for a given temperature by Figure ~~3.6.1~~ 3.4.9-1 A1. A1 SR 3.4.9.1.a

A1 LCO 3.4.9 The reactor vessel shall not be pressurized during heatup by non-nuclear means, during cooldown following nuclear shut down or during low level physics tests above the pressure allowable by Figure ~~3.6.2,~~ 3.4.9-2 A1 based on the temperatures recorded under 4.6.A. A1 SR 3.4.9.1.a

A1 LCO 3.4.9 The reactor vessel shall not be pressurized during operation with a critical core above the pressure allowable by Figure ~~3.6.3,~~ based on the temperatures recorded under 4.6.A. 3.4.9-3 SR 3.4.9.2 A1

~~SURVEILLANCE REQUIREMENTS~~

~~4.6 PRIMARY SYSTEM BOUNDARY~~

~~Applicability:~~

~~Applies to the periodic examination and testing requirements for the reactor coolant system.~~

~~Objective:~~

~~To determine the condition of the reactor coolant system and the operation of the safety devices related to it.~~

~~Specification:~~

~~A. Thermal and Pressurization Limitations~~ A1

SR 3.4.9.1 ~~1.~~ During heatups and cool-downs, the following temperatures shall be permanently logged at least every ~~15~~ 30 L1 minutes ~~until the difference between any 2 readings taken over a 45 minute period is less than 5° F.~~ R2 SR 3.4.9.1 Note

~~(a) Bottom head drain~~
~~(b) Recirculation loop A and B.~~ R3

A1 SR 3.4.9.1 ~~2.~~ Reactor vessel temperature and reactor coolant pressure shall be permanently logged at least every ~~15~~ 30 L1 minutes ~~whenever the shell temperature is below 220° F and the reactor vessel is not vented.~~ M1

~~Test specimens of the reactor vessel base, weld and heat affected zone metal were installed in the reactor vessel adjacent to the vessel wall at the core midplane level. The specimens and sample program shall conform to ASTM E 185-66 to the degree discussed in the FSAR.~~ R4

SR 3.4.9.2 → M2

Specification 3.4.9

~~LIMITING CONDITIONS FOR OPERATION~~

A1

~~3.6.A Thermal and Pressurization Limitations (Cont'd)~~

~~SURVEILLANCE REQUIREMENTS~~

~~4.6.A Thermal and Pressurization Limitations (Cont'd)~~

A2

~~Selected surveillance specimens shall be removed and tested in accordance with 10 CFR 50, Appendix H, to experimently verify or adjust the calculated values of integrated neutron flux and irradiation embrittlement that are used to determine the RT_{NDT} for Figures 3.6.1, 3.6.2 and 3.6.3, and the figures shall be updated based on the results.~~

LCO 3.4.9 A1

~~3.~~ 2.

The reactor vessel head bolting studs shall not be under tension unless the temperatures of the closure flanges and adjacent vessel and head materials are greater than 70° F.

A1 SR 3.4.9.5 SR 3.4.9.6 SR 3.4.9.7

A1 ~~3.~~ 2.

SR 3.4.9.5 SR 3.4.9.6 SR 3.4.9.7 and SRs Note

When the reactor vessel head bolting studs are tensioned and the reactor is in a Cold Condition, the reactor vessel shell temperature immediately below the head flange shall be permanently recorded.

LCO 3.4.9 A1

~~4.~~ 3.

The pump in an idle recirculation loop shall not be started unless the temperatures of the coolant within the idle and operating recirculation loops are within 50° F of each other.

SR 3.4.9.4 A1

A1 ~~4.~~ 3.

SR 3.4.9.4 and Note

Prior to and during startup A3 of an idle recirculation loop, the temperature of the reactor coolant in the operating and idle loops shall be permanently logged.

LCO 3.4.9 A1

~~5.~~ 4.

The reactor recirculation pumps shall not be started unless the coolant temperatures between the dome and the bottom head drain are within 145° F.

SR 3.4.9.3 A1

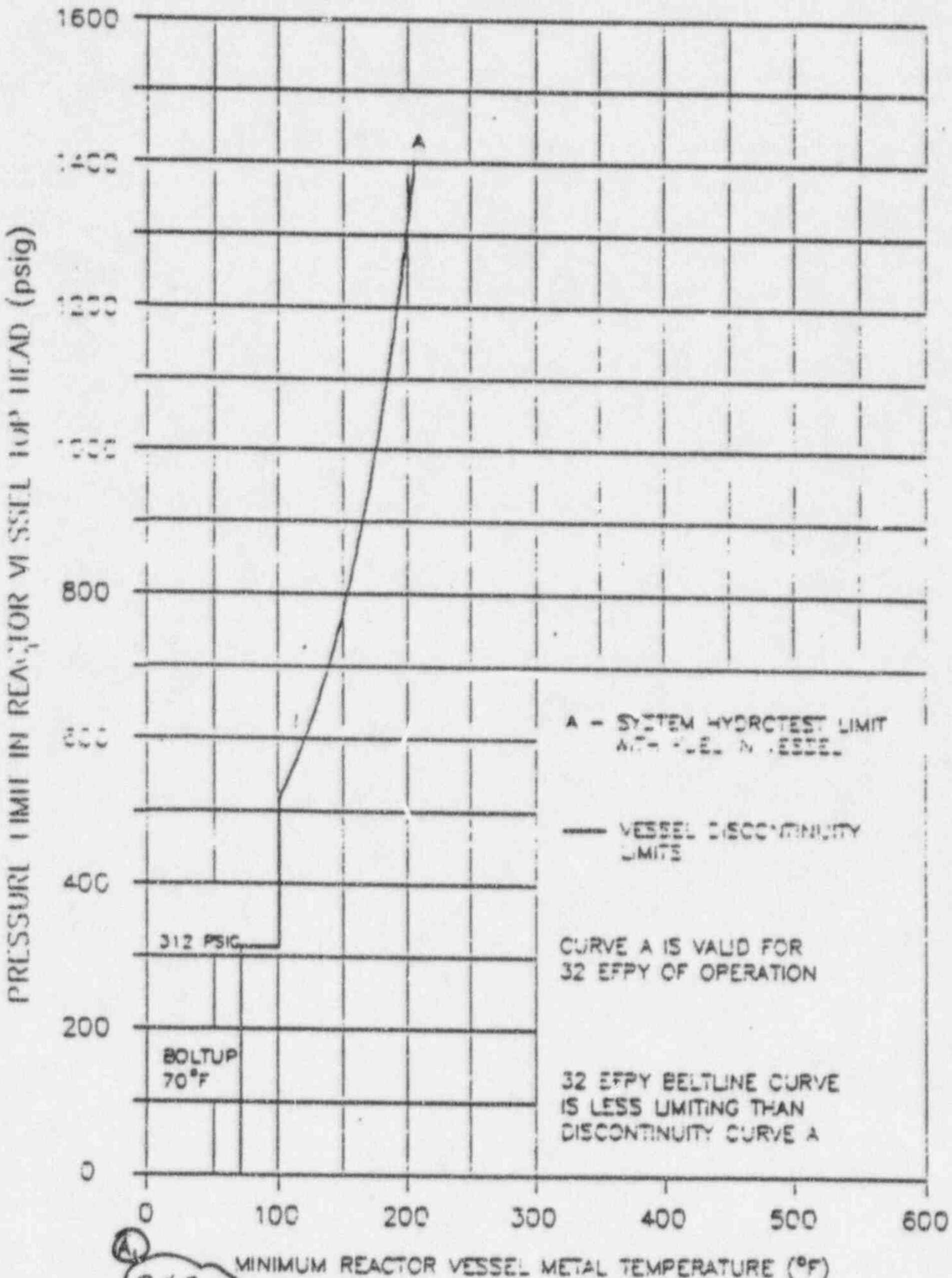
A1 ~~5.~~ 4.

SR 3.4.9.3 and Note

Prior to A3 starting a recirculation pump, the reactor coolant temperatures in the dome and in the bottom head drain shall be compared and permanently logged.

ACTIONS A, B, and C → M3

Frequencies for SR 3.4.9.5, SR 3.4.9.6, and SR 3.4.9.7 M4

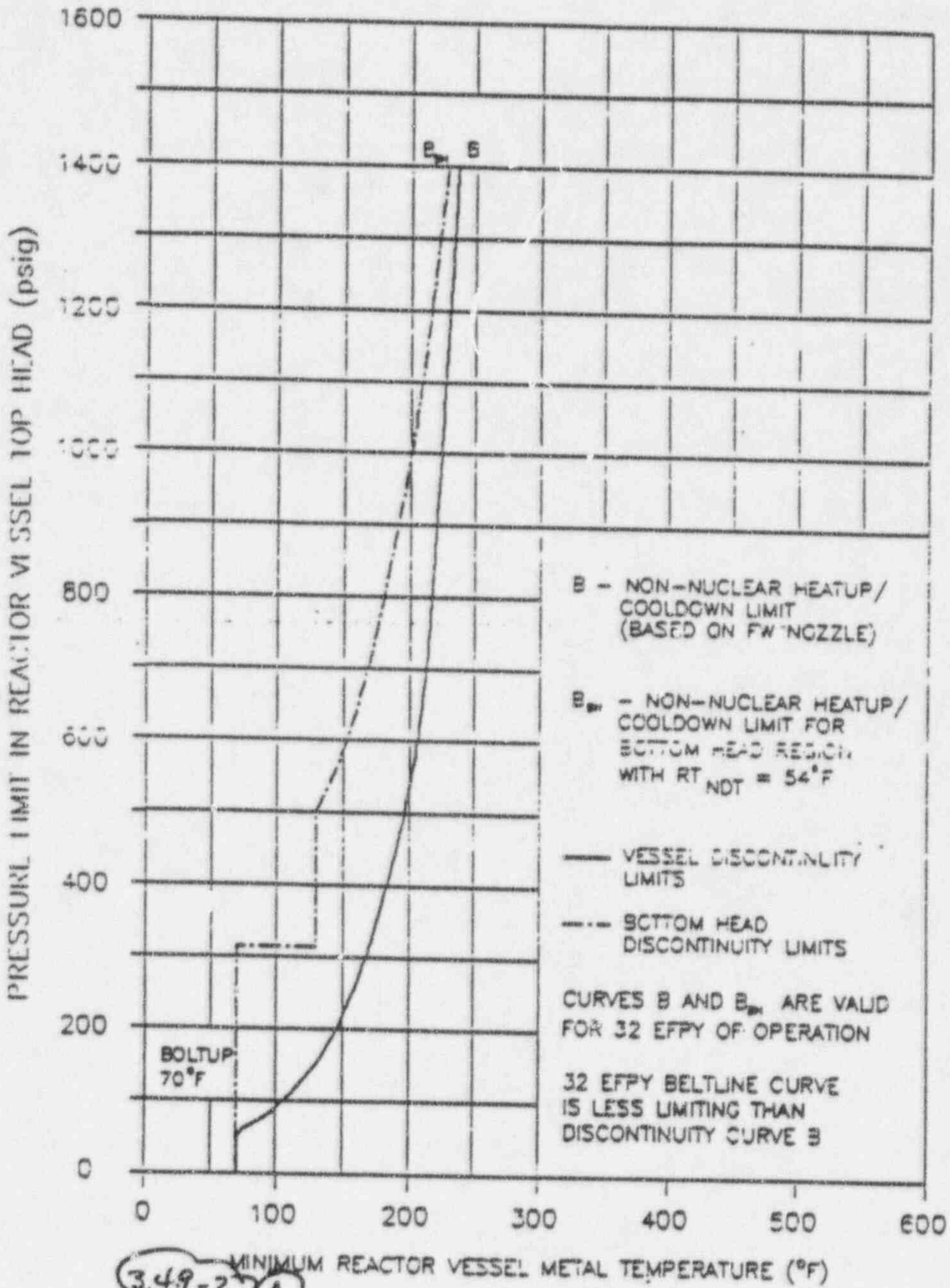


B

A

Figure ~~3.6.1~~ 3.4.9-1 Peach Bottom 3 Minimum Temperature for Pressure Tests Such as Required by Section XI

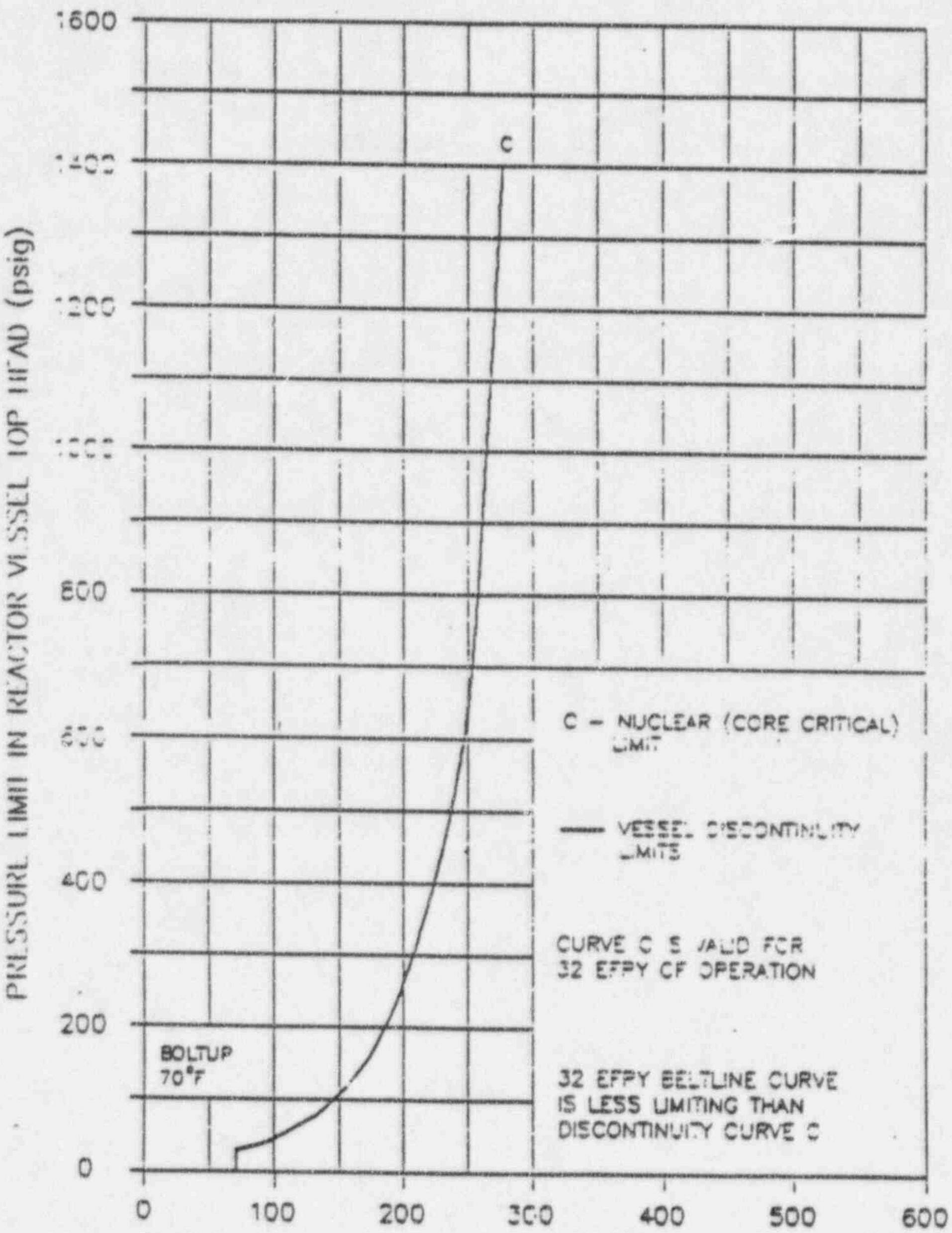
Specification 3.4.9



B

Figure ~~3.6.2~~ 3.4.9-2 A1 Peach Bottom 3 Minimum Temperature for Mechanical Heatup or Cooldown Following Nuclear Shutdown

Specification 3.4.9



B

A, 3.4.9 - 3

Figure ~~3.6.3~~ Peach Bottom 3 Minimum Temperature for Core Operation (Criticality)

JUN 27 1991

DISCUSSION OF CHANGES
ITS 3.4.9: RCS PRESSURE AND TEMPERATURE LIMITS

ADMINISTRATIVE CHANGES

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 These surveillances are a duplication of the regulations found in 10 CFR 50 Appendix H. These regulations require licensee compliance and cannot be revised by the licensee. Therefore, these details of the regulations within the Technical Specifications are repetitious and unnecessary. Furthermore, approved exemptions to the regulations, and exceptions presented within the regulations themselves, are also details which are adequately presented without repeating the details within the Technical Specifications. Therefore, retaining the requirement to meet the requirements of 10 CFR 50 Appendix H, as modified by approved exemptions, and eliminating the Technical Specification details that are also found in Appendix H, is considered a presentation preference which is administrative in nature.

A_3 For clarity, the terms "prior to and during startup" and "prior to" have been replaced with "15 minutes." This Frequency is effectively the same since the proposed Surveillance now must be performed no more than 15 minutes prior to startup of the idle recirculation loop. This is essentially equivalent to the current requirements.

DISCUSSION OF CHANGES
ITS 3.4.9: RCS PRESSURE AND TEMPERATURE LIMITS

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 The reactor vessel temperature and reactor coolant pressure surveillance in existing Specification 4.6.A.2 has been modified to require the surveillance to be performed any time the RCS pressure and temperature conditions are undergoing changes, not just "whenever the shell temperature is below 220°F and the reactor vessel is not vented." This change is necessary since the potential exists for violating a P/T limit at all times. This change represents an additional restriction on plant operation and is consistent with NUREG-1433.

M_2 A new Surveillance Requirement has been added. SR 3.4.9.2 ensures the RCS pressure and temperature are within the criticality limits once within 15 minutes prior to control rod withdrawal for the purpose of achieving criticality. This is an additional restriction on plant operation and is consistent with NUREG-1433.

M_3 ACTIONS have been added (proposed ACTIONS A, B, and C) to provide direction when the LCO is not met. Currently, no real ACTIONS are provided since current Specification 3.0.C does not provide adequate compensatory measures when the RCS P/T limits are not met. These ACTIONS are consistent with NUREG-1433 and are additional restrictions on plant operation.

M_4 Three new Surveillance Frequencies have been added. SR 3.4.9.5 ensures the vessel head is not tensioned at too low a temperature once per 30 minutes. SRs 3.4.9.6 and 3.4.9.7 ensure the vessel and head flange temperatures do not exceed the minimum allowed temperature once per 30 minutes and once per 12 hours, respectively. These are additional restrictions on plant operation since the current requirements have no times specified.

TECHNICAL CHANGES - RELOCATIONS

R_1 Not used. 3

R_2 The criteria for when the RCS temperature surveillance for heatup and cooldowns may be discontinued (until the difference between any 2 readings taken over a 45 minute period is less than 5°F) have been relocated to plant procedures. Changes to these procedures will be controlled using 10 CFR 50.59.

TECHNICAL CHANGES - RELOCATIONS (continued)

R_3 The specific RCS locations (bottom head drain and recirculation loops A and B) for monitoring temperature during heatups and cooldowns have been relocated to plant surveillance procedures. Changes to these procedures will be controlled using 10 CFR 50.59.

R_4 Reactor vessel test specimen location and associated details regarding the sample program have been relocated to the UFSAR. Changes to these details in the UFSAR will be controlled using 10 CFR 50.59.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 The frequency for verifying that RCS temperature and pressure are within limits has been extended from 15 minutes to 30 minutes. The 30 minute Frequency is considered adequate for maintaining RCS temperature and pressure within limits during planned changes in view of the available control room indication to monitor the RCS status and the fact that RCS heatup and cooldown operations and RCS inservice leak and hydrostatic tests are very controlled evolutions. In addition, industry operating experience has shown this frequency to be adequate for maintaining RCS temperature and pressure limits during planned evolutions. This change is consistent with NUREG-1433.

DISCUSSION OF CHANGES
ITS 3.4.10: REACTOR STEAM DOME PRESSURE

ADMINISTRATIVE CHANGES

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M_1 Proposed LCO 3.4.10, Reactor Steam Dome Pressure, and the associated Conditions, Required Actions, Completion Times, and a Surveillance Requirement have been added. The proposed LCO will require that reactor steam dome pressure be maintained less than or equal to 1053 psig while in Modes 1 and 2. A Surveillance will require that reactor steam dome pressure be verified within the proposed limit every 12 hours. If reactor steam dome pressure cannot be maintained within the proposed limit and cannot be restored within the required Completion Time, the reactor must be placed in Mode 3 within 12 hours. The reactor steam dome pressure limit of less than or equal to 1053 psig is an assumption used in the Power Rerate Safety Analysis for Peach Bottom 2 & 3. This proposed additional restriction is consistent with NUREG-1433 and helps ensure the safety analysis assumptions are maintained.

TECHNICAL CHANGES - RELOCATIONS

None

TECHNICAL CHANGES - LESS RESTRICTIVE

None

DISCUSSION OF CHANGES
CTS 3.6.B.2: COOLANT CHEMISTRY

ADMINISTRATIVE CHANGES

None

TECHNICAL CHANGES - MORE RESTRICTIVE

None

TECHNICAL CHANGES - RELOCATIONS

R_1 Existing Specification 3.6.B.2 establishes the controls for reactor water quality including: chloride concentration; conductivity; and pH. The chemistry limits are provided to prevent long term component degradation and provide long term maintenance of acceptable structural conditions of the system. The associated surveillances are not required to ensure immediate Operability of the Reactor Coolant System. Therefore, this requirement specified in current Specifications does not satisfy the NRC Policy Statement Technical Specification Screening Criteria. This requirement will be relocated to a licensee controlled document. Changes to this requirement will require a 10 CFR 50.59 evaluation. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - LESS RESTRICTIVE

None

DISCUSSION OF CHANGES
CTS 3.6.G: STRUCTURAL INTEGRITY

ADMINISTRATIVE CHANGES

None

TECHNICAL CHANGES - MORE RESTRICTIVE

None

TECHNICAL CHANGES - RELOCATIONS

R_1 The structural integrity inspections are provided to prevent long term component degradation and provide long term maintenance of acceptable structural conditions of the system. The associated inspections are not required to ensure immediate Operability of the system. Therefore, this requirement specified in current Specifications does not satisfy the NRC Policy Statement Technical Specification Screening Criteria. This requirement will be relocated to a licensee controlled document. Changes to this requirement will require a 10 CFR 50.59 evaluation. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - LESS RESTRICTIVE

None

DISCUSSION OF CHANGES
ITS 3.4: REACTOR COOLANT SYSTEM BASES

The Bases of the current Technical Specifications for this section (pages 151 through 161) have been completely replaced by revised Bases that reflect the format and applicable content of proposed PBAPS Units 2 and 3 Technical Specifications Section 3.4, consistent with NUREG-1433. The revised Bases are as shown in the proposed PBAPS Units 2 and 3 Bases. In addition, pages 149c (Unit 2 only), 150, 162, 163, and 164c, which are blank pages, have been deleted.

TECHNICAL CHANGES - RELOCATIONS

R_2 (cont'd) of, and the necessary compensatory actions if not available, for indicators, monitoring instruments, and alarms are addressed by plant procedures. Therefore, the requirements for testing this type of instrumentation are being relocated to plant procedures.

R_3 Existing Specification 4.5.G.1 presents technical details of the method to be employed to assure that the HPCI and RCIC discharge pump discharge lines are full of water as is required by existing Surveillance Requirement 4.5.G and proposed Surveillance Requirement 3.5.1.1. Details pertaining to how LCO's are verified or surveillance tests are performed, including existing Specification 4.5.G.1, are being relocated to the Bases and appropriate plant procedures. Relocating the specific details of the performance of surveillances that ensure the HPCI and RCIC pump discharge lines are full of water does not eliminate the requirement to maintain these components Operable. This change is consistent with NUREG-1433.

R_4 Existing Specification 4.5.G.2 requires that the level switches that monitor the LPCI and CS lines to ensure these lines are filled with water are functionally tested every operating cycle. In general, NUREG-1433 does not specify that indication only equipment be Operable to support the Operability of a system or component. Control of the availability of, and the necessary compensatory actions if not available, for indicators, monitoring instruments, and alarms are addressed by plant procedures. Therefore, the requirement for testing the LPCI and CS pump discharge line level switches is being relocated to plant procedures. This change is consistent with NUREG-1433.

R_5 Specifications 3.5.H and 4.5.H, Engineered Safeguards Compartments Cooling and Ventilation, are being relocated to plant procedures. The requirement for testing the compartment coolers was relocated to plant procedures. Details on testing some support systems have been relocated to licensee controlled documents. Relocating requirements for the compartment coolers does not preclude them from being maintained Operable. They are required to be Operable in order for the HPIC, RCIC, LPCI and CS systems to be Operable by the definition of Operability. This change is consistent with NUREG-1433. B

Specification 3.5.2

A1

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS
3.5.F Minimum Low Pressure Cooling Availability	4.5.F Minimum Low Pressure Cooling Availability

~~1~~. The following low pressure ECCS subsystems shall be OPERABLE when irradiated fuel is in the reactor vessel and the reactor is in the Cold Condition except when the reactor vessel head is removed, the spent fuel storage pool gates are removed, water level is at least 458 inches above reactor pressure vessel instrument zero and no work is being done with the potential for draining the reactor vessel: (A1) Applicability

LCO 3.5.2 (A1) ~~a~~. Two Core Spray (CS) subsystems (A2) with each subsystem comprised of: (R1)

(1) Two OPERABLE motor driven pumps, and

(2) Piping and valves capable of taking suction from the required water source and transferring the water through a spray sparger above the core to the reactor vessel.

OR

LCO 3.5.2 (A1) b. One CS subsystem (A2) comprised of the equipment specified in 3.5.F.1.a above, and (R1)

one Low Pressure Coolant Injection subsystem (A2) comprised of:

(1) One OPERABLE motor driven pump, and

(2) Piping and valves capable of taking suction from the required water source and transferring the water to the reactor vessel. (R1)

(A1) SR 3.5.2.1 ~~1~~. At least once per 12 hours, verify for each required Low Pressure Coolant Injection (LPCI) subsystem that the suppression pool water level is at least 11.0 feet.

~~2~~. At least once per 12 hours, verify for each required Core Spray (CS) subsystem: (A1) SR 3.5.2.2

(a) Suppression pool water level is at least 11.0 feet, or (B)

(b) Condensate storage tank water level is at least 17.3 feet.*

~~3~~. At least once per month, verify for each required CS and LPCI subsystem that the piping is filled with water from the pump discharge valve to the injection valve. SR 3.5.2.3 (A)

~~4~~. At least once per month, verify for each required CS and LPCI 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.** (A1) SR 3.5.2.4

* Only one required CS subsystem may take credit for this option during operations with a potential for draining the reactor vessel.

Note to SR 3.5.2.2.b

** One ~~LPCI subsystem may~~ be considered OPERABLE during alignment and operation for decay heat removal if capable of being manually realigned and not otherwise inoperable.

Note to SR 3.5.2.4

Page 1 of 4

Specification 3.5.2

(A1)

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS
3.5.F Minimum Low Pressure Cooling Availability	4.5.F Minimum Low Pressure Cooling Availability

~~1~~. The following low pressure ECCS subsystems shall be OPERABLE when irradiated fuel is in the reactor vessel and the reactor is in the Cold Condition except when the reactor vessel head is removed, the spent fuel storage pool gates are removed, water level is at least 458 inches above reactor pressure vessel instrument zero and no work is being done with the potential for draining the reactor vessel:

(A1) Applicability

(A1) LCO 3.5.2 ~~a~~. Two Core Spray (CS) subsystems (A2) with ~~each subsystem~~ comprised of:

(1) Two OPERABLE motor driven pumps, and

(2) Piping and valves capable of taking suction from the required water source and transferring the water through a spray sparger above the core to the reactor vessel. (R1)

OR

(A1) LCO 3.5.2 ~~b~~. One CS subsystem (A2) comprised of the equipment specified in 3.5.F.1.a above, (R1) and

one Low Pressure Coolant Injection (A2) subsystem comprised of:

(1) One OPERABLE motor driven pump, and

(2) Piping and valves capable of taking suction from the required water source and transferring the water to the reactor vessel. (R1)

~~1~~. (A1) SR 3.5.2.1 At least once per 12 hours, verify for each required Low Pressure Coolant Injection (LPCI) subsystem that the suppression pool water level is at least 11.0 feet.

~~2~~. (A1) SR 3.5.2.2 At least once per 12 hours, verify for each required Core Spray (CS) subsystem:

(a) Suppression pool water level is at least 11.0 feet, or (B)

(b) Condensate storage tank water level is at least 17.3 feet.*

~~3~~. SR 3.5.2.3 (A1) At least once per month, verify for each required CS and LPCI subsystem that the piping is filled with water from the pump discharge valve to the injection valve.

~~4~~. (A1) SR 3.5.2.4 At least once per month, verify for each required CS and LPCI 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.**

* Only one required CS subsystem may take credit for this option during operations with a potential for draining the reactor vessel.

Note to SR 3.5.2.2.b

** One LPCI subsystem may be considered OPERABLE during alignment and operation for decay heat removal if capable of being manually realigned and not otherwise inoperable.

Note to SR 3.5.2.4

TECHNICAL CHANGES - RELOCATIONS

R_1 The requirement to include automatic restart on low water level signal during a simulated automatic actuation test once per cycle was relocated to the Bases. This test requirement will be included as part of the RCIC actuation test description of the Bases for SR 3.5.3.5. This change is consistent with NUREG-1433.

R_2 The requirement to verify automatic transfer from CST to suppression pool on low CST water level once per cycle was relocated to the Bases. This test requirement will be included as part of the RCIC actuation test description of the Bases for SR 3.5.3.5. This change is consistent with NUREG-1433.

R_3 The requirement to ensure that the piping is full from the discharge valve to the injection valve by venting the RCIC from the high point was relocated to the Bases and appropriate plant procedures.

Details on how to perform tests or details of tests are being relocated to licensee controlled documents. This change is consistent with NUREG-1433.

R_4 The requirement for testing the compartment coolers was relocated to plant procedures. Details on testing some support systems have been relocated to licensee controlled documents. Relocating the compartment coolers does not preclude them from being maintained Operable. They are required to be Operable in order for the RCIC pumps to be Operable by the definition of Operability. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 This change proposes to extend the current allowed outage time for one RCIC System from 7 days to 14 days. The 14 days are allowed only if the HPCI System is verified Operable immediately. Loss of the RCIC System will not affect the overall plant capability to provide makeup inventory at high reactor pressure since the HPCI System is the only high pressure system assumed to function during a LOCA. However, the RCIC System is the preferred source of makeup for transients and certain abnormal events with no LOCA (RCIC as opposed to HPCI is the preferred source of makeup coolant because of its relatively small capacity, which allows easier control of the RPV water level). The 14 day completion time is also based on a reliability study that evaluated the impact on ECCS availability

Specification 3.6.1.2

Insert A
(4 of 4)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.2.2	------------------NOTE------------------ Only required to be performed upon entry into ~~or exit through the~~ primary containment ~~air lock~~ when the primary containment is de-inerted. -- Verify only one door in the primary containment air lock can be opened at a time.	184 days

B

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.2.2	------------------NOTE------------------ Only required to be performed upon entry into ~~or exit through the~~ primary containment ~~air lock~~ when the primary containment is de-inerted. -- Verify only one door in the primary containment air lock can be opened at a time.	184 days

B

Specification 3.6.1.3

~~PBAPS~~ UNIT 2

~~LIMITING CONDITIONS FOR OPERATION~~ A1 A1 ~~SURVEILLANCE REQUIREMENTS~~

LCO 3.6.1.3 ~~3.7.D Primary Containment Isolation Valves~~ Each PCIV except Reactor Building vacuum breakers and SDV vent or drain valves shall be operable

2. During ~~reactor power operating conditions~~, all isolation valves listed in Table 3.7.1 and all reactor instrument line excess flow check valves shall be operable except as specified in 3.7.D.2 and 3.7.D.3 below. A1 except for MSIV leakage not within limits. Applicability M1 R1

A2 Action Notes

A1

2. In the event any isolation valve specified in Table 3.7.1 becomes inoperable for isolation, maintain at least one isolation valve operable in the affected penetration that is open and within 4 hours either: 8 hours for MSIVs only L1 R1

Condition A & C Required Actions A.1, C.1

a. ~~Restore the inoperable valve to operable status, or~~ A1

b. Isolate the affected penetration by use of at least one deactivated automatic valve secured in the isolation position*, or

c. Isolate the affected penetration by use of at least one closed manual valve* or blind flange, or check valve with flow through the valve secured L5

d. Action Otherwise be in at least Hot Shutdown within the next 12 hours and in Cold Shutdown within the following 24 hours.

Required Actions A.2 & C.2 M8

Action B M5

Action D L1

Action Note 1 M11

*Isolation valves closed to satisfy these requirements may be reopened on an intermittent basis under administrative control.

~~4.7.D Primary Containment Isolation Valves~~

1. ~~The primary containment isolation valve surveillance shall be performed as follows:~~ A1

a. At least once per operating cycle the operable isolation valves that are power operated and automatically initiated shall be tested for simulated automatic initiation and closure times. SR 3.6.1.3.10 SR 3.6.1.3.8 actuator A2 In accordance with the IST Program M12 A ≤ for MSIVs In accordance with the IST Program

b. ~~At least~~ once per quarter:

(1) All normally open power operated isolation valves (except for the main steam line power operated isolation valves) shall be fully closed and reopened. R5 A1

SR 3.6.1.3.9 R6

(2) With the reactor power less than 75% trip main steam isolation valves individually and verify closure time. D6 92 days per IST

c. At least once per week the main steam line power-operated isolation valves shall be exercised by partial closure and subsequent reopening. R7

2. Whenever an isolation valve listed in Table 3.7.1 is inoperable, the position of at least one other valve in each line having an inoperable valve shall be recorded daily. R1 L8

3. The isolation valves specified in Table 3.7.1 shall be demonstrated to be operable prior to returning to service after maintenance on or replacement of the valve, actuator, control or power circuit by performance of a cycling test, and verification of isolation time. R3 R1

~~3.7.D Primary Containment Isolation Valves~~ LCO 3.6.1.3 Each PCIV except Reactor Bldg. vacuum breakers and suppression chamber vent & drain valves shall be Operable A1

~~4.7.D Primary Containment Isolation Valves~~

During reactor power operating conditions, all isolation valves listed in Table 3.7.1 and all reactor instrument line excess flow check valves shall be operable except as specified in 3.7.D.2 and 3.7.D.3 below. Applicability A1 except for MSIV leakage not within limits A4

In the event any isolation valve specified in Table 3.7.1 becomes inoperable for isolation, maintain at least one isolation valve operable in the affected penetration that is open and within 4 hours either: 8 hours for MSIVs L1 ACTION NOTES A2

Condition A & Required Action A.1.1

~~a. Restore the inoperable valve to operable status, or~~ A1

b. Isolate the affected penetration by use of at least one deactivated automatic valve secured in the isolation position*, or

c. Isolate the affected penetration by use of at least one closed manual valve* or blind flange. or check valve with flow through the valve secured L5

d. Otherwise be in at least Hot Shutdown within the next 12 hours and in Cold Shutdown within the following 24 hours. Action E

Required Actions A.2 & C.2 M8

Action B M5

Action D L1

Action Note M11

*~~Isolation valves closed to satisfy these requirements may be reopened on an intermittent basis under administrative control.~~

~~a. The primary containment isolation valve surveillance shall be performed as follows:~~ A1

~~a.~~ At least once per operating cycle the operable isolation valves that are power operated and automatically initiated shall be tested for simulated automatic initiation and closure times. SR 3.6.1.3.10 SR 3.6.1.3.6 M12 actual or A3

~~b.~~ ~~At least~~ once per quarter: In Accordance with the IST Program A5 for MSIVs

~~(1)~~ ~~All normally open power operated isolation valves (except for the main steam line power operated isolation valves) shall be fully closed and reopened.~~ R5

SR 3.6.1.3.9 R6
~~(2)~~ ~~With the reactor power less than 75%~~ trip main steam isolation valves individually and verify closure time. 92 day per IST

~~c.~~ ~~At least once per week the main steam line power-operated isolation valves shall be exercised by partial closure and subsequent reopening.~~ R7

~~2.e.~~ ~~Whenever an isolation valve listed in Table 3.7.1 is inoperable, the position of at least one other valve in each line having an inoperable valve shall be recorded daily.~~ L8 R1

~~b. The isolation valves specified in Table 3.7.1 shall be demonstrated to be operable prior to returning to service after maintenance on or replacement of the valve, actuator, control or power circuit by performance of a cycling test and verification of isolation tim~~ R3

B

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L_2 This change relaxes the allowed outage time (AOT) from 4 hours to 12 hours for penetrations in which the excess flow check valve is the only PCIV. The completion time is reasonable considering it is a closed system and the instrument and the small pipe diameter of the penetration. This AOT extension is considered acceptable because of the low probability of an event requiring a containment isolation function concurrent with a rupture of the piping in the closed system.

L_3 Not used.

L_4 Not used. B

L_5 A new method of isolating penetrations was added to the condition when one or more penetration flow paths with one PCIV inoperable (except for when MSIV leakage is not within limits). The new method allows the penetration to be isolated by a check valve with flow through the valve secured. This is acceptable for penetrations with only one PCIV inoperable because the other PCIV remains Operable, the likelihood of a event occurring in which a containment isolation is required is remote, the penetration is isolated by a check valve, and the other PCIV not being able to also isolate the penetration is remote. This description has also been added to the Bases to describe a passive PCIV.

L_6 Not used.

L_7 This change proposes to relax the amount of liquid nitrogen stored in the CAD nitrogen storage tank from 2500 gallons to 16 inches water column which equates to less than 2500 gallons. The minimum inventory required in the CAD nitrogen storage tank for primary containment purge and exhaust valve Operability is being changed to the minimum inventory required for Safety Grade Instrument Gas (SGIG) System. The requirement for the minimum level in the tank for CAD System Operability (2500 gallons) exists in the CAD System Technical Specification. Therefore, this requirement will be adequately maintained. However, there exists a minimum requirement for inventory in the tank for the SGIG System (which supports primary containment purge and exhaust valve Operability) which is less than required for the CAD System. The minimum level required for SGIG System to support the Operability of the components supplied by the SGIG System is 16 inches water column. This minimum tank level to support the Operability of components supplied by the SGIG System has been specified in the individual component Technical Specifications.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L_8 This change proposes to relax the requirement to record isolation valve position of at least one valve in the affected line with one isolation valve inoperable from daily to only verify valve position once per 31 days for valves (isolation devices) outside containment and prior to entering MODE 2 or 3 from MODE 4, if primary containment was de-inerted while in MODE 4, if not performed in the previous 92 days for valves (isolation devices) inside containment. The extension of the verification is acceptable based on the administrative controls governing PCIV operation, the low probability of valve misalignment and the accessibility of the valves.

L_9 The reasons that the large primary containment purge and exhaust isolation valves may be opened are proposed to be expanded to also include ALARA or air quality considerations for personnel entry or for Surveillances that require the valves to be open. This is considered acceptable since these purge and exhaust valves are capable of closing in the environment following a LOCA and the accumulated time a purge or exhaust valve flow path exists will be limited (currently 90 hours per calendar year) by licensee administrative controls. This change is consistent with NUREG-1433.

~~LIMITING CONDITIONS FOR OPERATION~~ (A1) ~~SURVEILLANCE REQUIREMENTS~~

3.5.A Core Spray and LPCI Subsystem (cont'd)

6. All recirculation pump discharge valves shall be operable prior to reactor startup (or closed if permitted elsewhere in these specifications).

7. If the requirements of 3.5.A cannot be met, an orderly shutdown of the reactor shall be initiated and the reactor shall be in the Cold Shutdown Condition within 48 hours.

~~B. Containment Cooling System (HPSW, Torus Cooling, Drywell Spray, and Torus Spray)~~

~~1. Except as specified in 3.5.B.2, 3.5.B.3, 3.5.B.4, 3.5.B.5, and 3.5.B.6 below,~~ (A1) the containment cooling system shall be operable whenever irradiated fuel is in the reactor vessel and reactor coolant temperature is greater than 212 degrees F, and prior to reactor startup from a Cold Shutdown Condition.

Applicability (A1)

4.5.A Core Spray and LPCI Subsystem (cont'd)

6. All recirculation pump discharge valves shall be tested for operability during any period of reactor cold shutdown exceeding 48 hours, if operability tests have not been performed during the preceding 31 days.

<See Discussion of Changes for ITS 3.5.1, ECCS - Operating>

(A1)

3.6.2.3 RHR Suppression Pool Cooling

~~B. Containment Cooling System (HPSW, Torus Cooling, Drywell Spray, and Torus Spray)~~ (A1)

~~1. Containment Cooling System components shall be tested as follows:~~ (A1)

~~Item~~ (A1)		~~Frequency~~
(a)	Each HPSW Pump Operability.	Once/month
(b)	Each HPSW motor operated valve operability.	Once/month
(c)	HPSW Pump Capacity Test. Each HPSW pump shall deliver 4500 gpm at 233 psig.	After pump maintenance and every 3 months.
(R1) ~~(d)~~	~~Each Torus Cooling motor operated valve operability.~~	~~Once/month~~ ~~quarter~~
(e)	Each Drywell Spray motor operated valve operability.	Once/month
(f)	Each Torus Spray motor operated valve operability.	Once/month
(g)	Air test on drywell and torus headers and nozzles.	Once/5 years

<See Discussion of Changes for ITS 3.7.1, HPSW System>

<See Discussion of Changes for ITS 3.6.2.4, RHR Suppression Pool Spray>

B

~~LIMITING CONDITIONS FOR OPERATION~~ A1 ~~SURVEILLANCE REQUIREMENTS~~

3.5.A Core Spray and LPCI Subsystem (cont'd)

6. All recirculation pump discharge valves shall be operable prior to reactor startup (or closed if permitted elsewhere in these specifications).

7. If the requirements of 3.5.A cannot be met, an orderly shutdown of the reactor shall be initiated and the reactor shall be in the Cold Shutdown Condition within 48 hours.

~~B. Containment Cooling System (HPSW, Torus Cooling, Drywell Spray, and Torus Spray)~~ A1

~~1. Except as specified in 3.5.B.2, 3.5.B.3, 3.5.B.4, 3.5.B.5, and 3.5.B.6 below,~~ A1 the containment cooling system shall be operable whenever irradiated fuel is in the reactor vessel and reactor coolant temperature is greater than 212 degrees F, and prior to reactor startup from a Cold Shutdown Condition.

Applicability A1

4.5.A Core Spray and LPCI Subsystem (cont'd)

6. All recirculation pump discharge valves shall be tested for operability during any period of reactor cold shutdown exceeding 48 hours, if operability tests have not been performed during the preceding 31 days.

See Discussion of Changes for ITS 3.5.1, ECCS-Operating

3.6.2.3 RHR Suppression Pool Cooling A1

~~B. Containment Cooling System (HPSW, Torus Cooling, Drywell Spray, and Torus Spray)~~ A1

~~1. Containment Cooling System components shall be tested as follows:~~

~~Item~~ A		~~Frequency~~
(a)	Each HPSW Pump Operability.	Once/month
(b)	Each HPSW motor operated valve operability.	Once/month
(c)	HPSW Pump Capacity Test. Each HPSW pump shall deliver 4500 gpm at 233 psig.	After pump maintenance and every 3 months.
(d)	Each Torus Cooling motor operated valve operability. R1	Once/~~month~~ L1 ~~quarter~~
(e)	Each Drywell Spray motor operated valve operability.	Once/month
(f)	Each Torus Spray motor operated valve operability.	Once/month
(g)	Air test on drywell and torus headers and nozzles.	Once/5 years

See Discussion of Changes for ITS 3.7.1, HPSW System

See Discussion of Changes ITS 3.6.2.4, RHR Suppression Pool Spray

B

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 Not used.

L_2 The proposed change modifies Completion Times for the Required Actions when a Required Action and associated Completion Time specified in the Technical specifications cannot be met. Existing LCO 3.5.B.7, entered when the requirements of LCO 3.5.B.4 cannot be met, requires that the reactor be placed in Cold Shutdown within 24 hours. The proposed specification, LCO 3.6.2.3, Condition C, will require that the reactor be in Mode 3 within 12 hours and Mode 4 within 36 hours whenever a Required Action and associated Completion Time is not met. The change from Cold Shutdown within 24 hours to Mode 3 within 12 hours and Mode 4 within 36 hours will require that the plant be shutdown sooner than the existing specifications but allows for a more controlled cooldown which reduces thermal stress on components and also reduces the chances for a plant transient which could challenge safety systems. This change is consistent with NUREG-1433 and the BWR/4 STS, Revision 4.

Specification 3.6.2.4

TSCR 94-01

~~LIMITING CONDITIONS FOR OPERATION~~ (A1) ~~SURVEILLANCE REQUIREMENTS~~

~~3.5.A Core Spray and LPCI Subsystem (cont'd)~~

6. All recirculation pump discharge valves shall be operable prior to reactor startup (or closed if permitted elsewhere in these specifications).

7. If the requirements of 3.5.A cannot be met, an orderly shutdown of the reactor shall be initiated and the reactor shall be in the Cold Shutdown Condition within 48 hours.

~~B. Containment Cooling System (HPSW, Torus Cooling, Drywell Spray, and Torus Spray)~~

~~1. Except as specified in 3.5.B.2, 3.5.B.3, 3.5.B.4, 3.5.B.5, and 3.5.B.6 below,~~ the containment cooling system shall be operable whenever irradiated fuel is in the reactor vessel and reactor coolant temperature is greater than 212 degrees F, and prior to reactor startup from a Cold Shutdown Condition.

Applicability (A1)

~~4.5.A Core Spray and LPCI Subsystem (cont'd)~~

6. All recirculation pump discharge valves shall be tested for operability during any period of reactor cold shutdown exceeding 48 hours, if operability tests have not been performed during the preceding 31 days.

See Discussion of Changes for ITS 3.5.1, ECCS - Operating

(A1) 3.6.2.4 Residual Heat Removal (RHR) Suppression Pool Spray

~~B. Containment Cooling System (HPSW, Torus Cooling, Drywell Spray, and Torus Spray)~~ (A1)

~~1. Containment Cooling System components shall be tested as follows:~~ (A1)

~~Item~~	~~Frequency~~
(a) Each HPSW Pump Operability.	Once/month
(b) Each HPSW motor operated valve operability.	Once/month
(c) HPSW Pump Capacity Test. Each HPSW pump shall deliver 4500 gpm at 233 psig.	After pump maintenance and every 3 months.
(d) Each Torus Cooling motor operated valve operability.	Once/month
(R2) (e) Each Drywell Spray motor operated valve operability.	Once ~~month~~ quarter ~~X~~
(R1) (f) Each Torus Spray motor operated valve operability.	Once ~~month~~
~~(g)~~ Air test on ~~drywell and torus~~ headers and nozzles. (R2)	Once/~~5~~ 10 years (L2)

See Discussion of Changes for ITS 3.7.1, HPSW System

See Discussion of Changes for ITS 3.6.2.3, RHR Suppression Pool Cooling

(A1) SR 3.6.2.4.2

RHR Suppression pool (A1)

Page 1 of 6

A1

~~LIMITING CONDITIONS FOR OPERATION~~ | ~~SURVEILLANCE REQUIREMENTS~~

3.5.A Core Spray and LPCI Subsystem (cont'd)

6. All recirculation pump discharge valves shall be operable prior to reactor startup (or closed if permitted elsewhere in these specifications).

7. If the requirements of 3.5.A cannot be met, an orderly shutdown of the reactor shall be initiated and the reactor shall be in the Cold Shutdown Condition within 48 hours.

~~B. Containment Cooling System (HPSW, Torus Cooling, Drywell Spray, and Torus Spray)~~ A1

~~1. Except as specified in 3.5.B.2, 3.5.B.3, 3.5.B.4, 3.5.B.5, and 3.5.B.6 below,~~ the containment cooling system shall be operable whenever irradiated fuel is in the reactor vessel and reactor coolant temperature is greater than 212 degrees F, and prior to reactor startup from a Cold Shutdown Condition.

Applicability A1

4.5.A Core Spray and LPCI Subsystem (cont'd)

6. All recirculation pump discharge valves shall be tested for operability during any period of reactor cold shutdown exceeding 48 hours, if operability tests have not been performed during the preceding 31 days.

See Discussion of Changes for ITS 3.5.1, ECCS-Operating

3.6.2.4 Residual Heat Removal (RHR) Suppression Pool Spray A1

~~B. Containment Cooling System (HPSW, Torus Cooling, Drywell Spray, and Torus Spray)~~ A1

~~1. Containment Cooling System components shall be tested as follows:~~

~~Item~~	~~Frequency~~ A1
(a) Each HPSW Pump Operability.	Once/month
(b) Each HPSW motor operated valve operability.	Once/month
(c) HPSW Pump Capacity Test. Each HPSW pump shall deliver 4500 gpm at 233 psig.	After pump maintenance and every 3 months.
(d) Each Torus Cooling motor operated valve operability.	Once/month
R2 (e) Each Drywell Spray motor operated valve operability.	Once/~~month~~ quarter
R1 (f) Each Torus Spray motor operated valve operability.	Once/~~month~~
A1 SR 3.6.2.4.2 ~~(g)~~ Air test on ~~drywell and torus,~~ headers and nozzles. R2	Once/~~5~~ 10 years L2

See Discussion of Changes for ITS 3.7.1, HPSW System

See Discussion of Changes for ITS 3.6.2.3, RHR Suppression Pool Cooling

RHR Suppression Pool Spray A1

TECHNICAL CHANGES - RELOCATIONS (continued)

R_3 Existing Specification 3.5.B.6a defines what constitutes an RHR suppression pool spray subsystem (loop) and describes the minimum requirements for an Operable flow path. These descriptions of the subsystems are relocated to the Bases of LCO 3.6.2.4.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 Not used.

L_2 The Frequency for performance of the spray nozzle obstruction surveillance test has been extended from 5 years to 10 years. This change is justified due to the passive design of the nozzles, and has been shown acceptable through industry operating experience. This change does not represent a significant increase in the probability of an accident because obstruction of the RHR suppression pool spray nozzles is not a precursor to any accident.

L_3 The proposed change modifies Completion Times for the Required Actions when a Required Action and associated Completion Time specified in the Technical specifications cannot be met. Existing LCO 3.5.B.7, entered when the requirements of LCO 3.5.B.6 cannot be met, requires that the reactor be placed in Cold Shutdown within 24 hours. The proposed specification, LCO 3.6.2.4, Condition C, will require that the reactor be in Mode 3 within 12 hours and Mode 4 within 36 hours whenever a Required Action and associated Completion Time is not met. The change from Cold Shutdown within 24 hours to Mode 3 within 12 hours and Mode 4 within 36 hours will require that the plant be shutdown sooner than the existing specifications but allows for a more controlled cooldown which reduces thermal stress on components and also reduces the chances for a plant transient which could challenge safety systems. This change is consistent with NUREG-1433 and the BWR/4 STS, Revision 4.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

M_2 The proposed change adds new Surveillance Requirements to the DC Sources—Operating Specification. These Surveillances are as follows:

- SR 3.8.4.2 - Verify no visible corrosion at battery terminals and connectors, or verify battery connection resistance is within limits once per 92 days. This Surveillance provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

- SR 3.8.4.3 - Verify battery cells, cell plates, and racks show no visual indication of physical damage or abnormal deterioration that could potentially degrade battery performance once per 12 months. This Surveillance provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance. B

- SR 3.8.4.4 - Remove visible corrosion, and verify battery cell to cell and terminal connections are coated with anti-corrosion material once per 12 months. This Surveillance provides an indication of physical damage or abnormal deterioration that could indicate degraded battery condition.

- SR 3.8.4.5 - Verify battery connection resistance is within limits once per 12 months. This Surveillance provides an indication of physical damage or abnormal deterioration that could indicate degraded battery condition.

- SR 3.8.4.6 - Verify each required battery charger supplies a required number of amps at the required voltage once per 24 months. This Surveillance verifies the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state.

The addition of new requirements constitutes a more restrictive change. This change is consistent with NUREG-1433.

Specification 3.8.6

A_1

~~4.9.A.2 Unit Batteries~~

L4 Proposed Note to Frequency and 14 day Frequency

SR 3.8.6.1

L3

~~a.~~ Every week the specific gravity, the voltage and (electrolyte level M3) temperature of the pilot cell and overall battery voltage shall be ~~measured and logged~~. (Float A1)

See Discussion of changes for ITS 3.8.4, "DC Sources Operating"

R1 M4 add additional Frequencies

SR 3.8.6.2

b. Every three months the measurements shall be made of voltage of each cell ~~to nearest 0.1 Volt~~, specific gravity of each cell, and temperature of every fifth cell. These ~~measurements shall be logged~~ R1

M5

M3 electrolyte level of each cell

L2 SR 3.8.6.3 temperature of representative cells

M2 Add Table 3.8.6-1

c. The station batteries shall be subjected to a performance test every second refueling outage and a service test during the other refueling outage. In lieu of the performance test every second refueling outage, any battery that shows "signs of degradation or has reached 85% of its service life" shall be subjected to an annual performance test. The service test need not be performed on the refueling outage during which the performance test was conducted. The specific gravity and voltage of each cell shall be determined after the discharge and logged.

See Discussion of change for ITS 3.8.4, "DC Sources Operating"

4.9.A.3 Swing Buses

a. Every two months the swing buses supplying power to the Low Pressure Coolant Injection System (LPCIS) valves shall be tested to assure that the transfer circuits operate as designed.

See Discussion of change for ITS 3.5.1, "ECCS-Operating"

~~LIMITING CONDITIONS FOR OPERATION~~ ~~SURVEILLANCE REQUIREMENTS~~

A1

L4 — Proposed Note to Frequency and M1 Any Frequency

~~4.9.A.2 Unit Batteries~~

A1 — float

M3 — electrolyte level

SR 3.8.6.1

a. Every ~~week~~ the specific gravity, the voltage and ~~temperature~~ of the pilot cell and ~~overall battery voltage~~ shall be ~~measured and logged.~~

L3

R1

See Discussion of change for ITS 3.8.4, "DC Sources - Operating"

M4 — add additional frequency

SR 3.8.6.2

b. Every three months the measurements shall be made of voltage of each cell ~~to nearest 0.1 volt~~, specific gravity of each cell, and ~~temperature of every fifth cell~~. These ~~measurements shall be logged.~~

M5

R1

M3 — electrolyte level of each cell

L2 — SR 3.8.6.3 temperature of representative cells

c. The station batteries shall be subjected to a performance test every second refueling outage and a service test during the other refueling outage. In lieu of the performance test every second refueling outage, any battery that shows "signs of degradation or has reached 85% of its service life" shall be subjected to an annual performance test. The service test need not be performed on the refueling outage during which the performance test was conducted. The specific gravity and voltage of each cell shall be determined after the discharge and logged.

M2 — Add Table 3.8.6-1

See Discussion of change for ITS 3.8.4, "DC Sources - Operating"

4.9.A.3 Swing Buses

a. Every two months the swing buses supplying power to the Low Pressure Coolant Injection System (LPCIS) valves shall be tested to assure that the transfer circuits operate as designed.

See Discussion of change for ITS 3.5.1, "ECCS - Operating"

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AUG 0 2 1993

TECHNICAL CHANGES - MORE RESTRICTIVE

M_3 (cont'd) limits ensure that the plates suffer no physical damage, and that adequate electron transfer capability is maintained in the event of transient conditions. The Frequency is also consistent with IEEE-450. This change is consistent with NUREG-1433.

M_4 This change proposes to add a additional Frequencies to SR 3.8.6.2 (verification of Category B limits in Table 3.8.6-1). The proposed requirement will add an additional requirement to test the battery cells once within 24 hours after battery discharge < 100 V and once within 24 hours after battery overcharge > 145 V. This proposed change is consistent with IEEE-450 which recommends special inspections following a severe discharge or overcharge, to ensure no significant degradation of the battery occurs as a consequence of such discharge or overcharge.

M_5 The requirement specifying cell voltage measurements be performed "to the nearest 0.1 volt" has been made more restrictive as a result of the acceptance criteria of Table 3.8.6-1. Table 3.8.6-1 specifies acceptance criteria for cell voltage of ≥ of 2.13 volts for Category A and B limits and ≥ 2.07 volts for Category C limits. This represents a more restrictive change since, to satisfy cell voltage requirements in Table 3.8.6-1, measurements must be performed to the nearest 0.01 volt.

B

TECHNICAL CHANGES - RELOCATIONS

R_1 The change will relocate items which are procedural in nature to procedures. These items will be retained in procedures and will require a 10 CFR 50.59 review in order to be changed. This change is consistent with NUREG-1433.

B

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 This change proposes to add an Action (Action A) which will relax the current requirements when battery parameters are not within limits. The current Actions, when one battery is inoperable, essentially require the affected battery to be declared inoperable and the Required Actions for the inoperable battery to be taken (72 hour allowed outage time). If more than one battery is affected the plant is required to shutdown per Specification 3.0.C. The proposed Action allows a 31 day restoration time (Action A.3) for one or more batteries with battery cell parameters not within Category A or B limits provided Action A.1 and A.2 are met as specified below.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 (cont'd)

- Action A.1: 1 hour is allowed to verify pilot cell electrolyte level and float voltage meet Table 3.8.6-1 Category C limits. This provides a quick indication of the status of the remainder of the battery cells. One hour provides time to inspect the electrolyte level and to confirm the float voltage of the pilot cells.

- Action A.2: 24 hours and once per 7 days thereafter is allowed to verify battery cell parameters meet Table 3.8.6-1 Category C limits. This provides assurance that during the time needed to restore the parameters to the Category A and B limits, the battery is still capable of performing its intended function. A period of 24 hours is allowed to complete the required verification because specific gravity measurements must be obtained for each connected cell. The 7 day interval is consistent with the normal Surveillance Frequency.

This change is consistent with NUREG-1433 and is considered acceptable since the interim actions prior to restoration of battery cell parameters require verifications to be performed which demonstrate that the affected battery while degraded still has sufficient capacity to perform its intended function.

L_2 This change proposes to relax the current requirement to verify the electrolyte temperature of every fifth cell every 92 days. The proposed change will require the average temperature of representative cells (10% of the total cells) to be within limits every 92 days. This change essentially reduces the number of cells tested from approximately 11 to approximately 6 for electrolyte temperature (based on a total of 58 cells). This requirement is consistent with the recommendation of IEEE-450 which states that the temperature of electrolyte in representative cells should be determined on a quarterly basis. However, this SR continues to ensure that the operating temperatures remain within an acceptable operating range.

L_3 This change proposes to relax the current requirement to verify electrolyte temperature of each pilot cell every 7 days. Proposed Surveillance SR 3.8.6.1 will require the 7 day pilot cell specific gravity verification to be corrected for temperature. Therefore, indirectly, the temperatures of the pilot cells are verified every 7 days. The proposed change relaxes the current requirement by not requiring the pilot cells to be directly surveilled per a specific

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L_3 (cont'd) Technical Specification Surveillance. Lower than normal temperatures act to inhibit or reduce battery capacity. This change will continue to ensure that the operating temperatures remain within an acceptable operating range.

L_4 The weekly Frequency has been modified to allow the Surveillance to not be performed if the battery is on equalize charge or has been on equalize charge any time during the previous 4 days. With the battery on equalize charge, meaningful results, as it relates to ensuring the required limits are met cannot be obtained, since the intent of the SR is to ensure the battery cell voltage is acceptable while on float charge, not while on equalize charge. Also, the specific gravity and electrolyte level results are not meaningful (for trending purposes) while on equalize charge. After completion of an equalize charge (performed following the battery being of float charge), it takes approximately 3 days for the electrolyte level to return to normal (due to elevated temperatures caused by the equalize charge) and be representative of a battery on float charge. The additional day provides time to perform the test and to ensure the battery cell parameters are representative of a float charge. This addition of the Note essentially allows an extension of the normal 7 day Frequency until the time that the parameters can be obtained while on float charge. This additional time is considered acceptable since the most probable result of performing this SR will be that the voltage, level, and specific gravity are acceptable; the battery has just completed an equalize charge. The 14 day Frequency has been added to ensure that the battery cannot be placed on equalize all the time, thus the SR would never be required. This ensures the SR is performed at least every 14 days, regardless of how often the battery is placed on equalize. This 14 days is still conservative with respect to the recommendations of IEEE-450, 1987.

specification 5.0

5.6.7 ~~Continued~~ 6 PAM Reports (A4) ~~Unique Reporting Requirements~~

~~Special reports shall be submitted to the NRC in accordance with 10 CFR 50.4 within the time period specified herein for each report. These reports shall be submitted covering the activities identified below pursuant to the requirements of the applicable reference specification:~~ (A1)

(R6)

a. Loss of shutdown margin, Specification 3.3.A and 4.3.A within 14 days of the event.

b. Reactor vessel inservice inspection, Specification 3.6.G and 4.6.G within 90 days of the completion of the reviews.

c. Report seismic monitoring instrumentation inoperable for more than 30 days (Specification 3.15.B) within the next 10 working days. Submit a seismic event analysis (Specification 4.15.B) within 10 working days of the event.

d. Primary containment leak rate testing approximately three months after the completion of the periodic integrated leak rate test (Type A) required by Specification 4.7.A.2.c.2. For each periodic test, leakage test results from Type A, B and C tests shall be reported. B and C tests are local leak rate tests required by Specification 4.7.A.2.f. The report shall contain an analysis and interpretation of the Type A test results and a summary analysis of periodic Type B and Type C tests that were performed since the last Type A test.

(R13)

e. Calculated dose from release of radioactive effluents, Specification 3.8.B.2, 3.8.B.4, 3.8.C.2, 3.8.C.3, 3.8.C.5, 3.8.D, and 3.8.E.1.b.

(R6)

f. Sealed source leakage in excess of limits, Specification 3.13.2.

(A4) When a report is required by Condition B or F of LCO 3.3.3.1, "Post Accident Monitoring Instrumentation ...

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in gaseous effluents (as determined by sampling frequency and measurement) shall be used for determining the gaseous pathway doses. Approximate methods are acceptable. The assessment of radiation doses shall be performed in accordance with the OFFSITE DOSE CALCULATION MANUAL (ODCM).

R13

The Radiation Dose Assessment Report shall also include an assessment of radiation doses to the likely most exposed MEMBER OF THE PUBLIC from reactor releases and other nearby uranium fuel cycle sources (including doses from primary effluent pathways and direct radiation) for the previous calendar year to show conformance with 40 CFR Part 190, Environmental Radiation Protection Standards for Nuclear Power Operation. Guidance for calculating the dose contribution from liquid and gaseous effluents are given in Regulatory Guide 1.109, Revision 1, October 1977. If doses from plant effluents do not exceed twice the Appendix I limits, a statement to that effect shall constitute a 40 CFR 190 assessment.

** In lieu of submission with the first half year Radioactive Effluent Release Report, the licensee will retain this summary of required meteorological data on site in a file that shall be provided to the NRC upon request.

M7

5.6.6 Add RCS Pressure and Temperature Limits Report

B

Specification 5.0

(L-6)

5.7 ~~6.13~~

High Radiation Area

As provided in paragraph 20.1601(c) of 10CFR Part 20, the following controls shall be applied to high radiation areas

~~6.13.1~~ In lieu of the ~~"control device" or "alarm signal"~~ controls required by paragraph ~~20.203(c)(2)~~ 20.1601(a) and (b) of 10 CFR 20:

5.7.1 a. Each High Radiation Area in which the intensity of radiation is greater than 100 mrem/hr but less than 1000 mrem/hr shall be barricaded and conspicuously posted as a High Radiation Area and entrance thereto shall be controlled by issuance of ~~a~~ STET ~~or group of~~ Radiation Work Permit. Any individual ~~individuals~~ STET permitted to enter such areas shall be provided with or accompanied by one or more of the following:

opened as necessary to permit

Such areas may be ~~locked~~ ~~during periods~~ ~~of~~ entry and exit of personnel or equipment

or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures

b.

Insert c.

d.

d.1. A radiation monitoring device which continuously indicates the radiation dose rate in the area.

d.2. A radiation monitoring device which continuously integrates the radiation dose rate in the area and alarms when a preset integrated dose is received. Entry into such areas with this monitoring device may be made after the dose rate levels in the area have been established and personnel have been made knowledgeable of them.

Except for individuals qualified in radiation protection procedures,

e.

B

Insert d.3

a direct-reading dosimeter and, be under surveillance, as specified in the RWP or equivalent while in the area, of

d.4(a) ~~3.~~ An individual qualified in radiation protection procedures who is equipped with a radiation dose rate monitoring device. This individual shall be responsible for ~~providing positive control over activities within the area and shall perform periodic radiation surveillance at the frequency specified by the plant health physicist or his designee on the Radiation Work Permit.~~

at the work site

controlling personnel radiation exposure in the area.

Insert d.4(b)

5.7.2 ~~b.~~ Each High Radiation Area in which the intensity of radiation is greater than 1000 mrem/hr shall be subject to ~~the provisions of 6.13.1 (a) above~~. In addition, locked doors shall be provided to prevent unauthorized entry into such areas and the keys shall be maintained under the administrative control of the ~~Shift Manager, the Shift Supervisor or the Senior Health Physicist.~~ radiation protection personnel

but less than 500 rads/hr

gate or guard

Insert 5.7.2

a.

a.1

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

Specification 5.0

Insert C

L6

Individuals qualified in radiation protection procedures 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.

B

Insert d.3

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

Insert d.4(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.

Specification 5.0

L6

Insert 5.7.2

B

~~5.7.1~~ a. ~~Each High Radiation Area in which the intensity of radiation is greater than 100 mrem/hr but less than 1000 mrem/hr shall be barricaded~~ and conspicuously posted as a High Radiation Area and entrance thereto shall be controlled by issuance of a Radiation Work Permit or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures. Any individual ~~or group of individuals~~ permitted to enter such areas shall be provided ~~with or accompanied~~ by one or more of the following:

~~Such areas may be barricaded during periods of entry and exit~~

5.7.2 b.

Insert 5.7.2C.

5.7.2 d.

~~(1)~~ ~~A radiation monitoring device which continuously indicates the radiation dose rate in the area.~~

5.7.2 d.1 A radiation monitoring device which continuously integrates the radiation dose rate in the area and alarms when a preset integrated dose is received. Entry into such areas with this monitoring device may be made after the dose rate levels in the area have been established and personnel have been made knowledgeable of them.

5.7.2 e. Except for individuals qualified in radiation protection procedures,

Insert 5.7.2 d.2 → A direct-reading dosimeter and, be under surveillance, as specified in the RWP or equivalent, ~~while in the area~~, of

5.7.2 d.3(a) An individual qualified in radiation protection procedures who is equipped with a radiation dose rate monitoring device. This individual shall be responsible for ~~providing positive control over activities within the area and shall perform periodic radiation surveillance at the frequency specified by the plant health physicist or his designee on the Radiation Work Permit.~~

Insert 5.7.2 d.3(b) → controlling personnel radiation exposure in the area.

Insert 5.7.2.d.4 →

Insert 5.7.2.d.4

B

4. A radiation monitoring and indicating device in those cases where the options of Specifications 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.

Insert 5.7.2C

Specification 5.0

L6

Individuals qualified in radiation protection procedures 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.

B

Insert 5.7.2d.~~3~~ 2

A radiation monitoring device that continuously transmits dose rate or cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area with a means to communicate with and control every individual in the area, or

Insert 5.7.2.d.~~4~~ 3 (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.

5.5.7 Ventilation Filter Testing ~~FBAPS~~ Program

Specification 5.0

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS

See Discussion of changes 3.6.4.3 "Standby Gas Treatment System"

3.7.B Standby Gas Treatment System

1. Except as specified in 3.7.B.3 below, both filter trains of the Standby Gas Treatment System and at least two system fans shall be operable at all times when secondary containment integrity is required. Only one of the two Standby Gas Treatment System (SGTS) trains shall be used at a time for primary containment purge/vent operations using the large isolation valves. Both SGTS trains shall be operable as required by Specification 3.7.E.

5.5.7.a / 5.5.7.b

2a. The results in the in-place cold DOP and halogenated hydrocarbon tests at approximately 8000 (7200 to 8800) CFM on HEPA filters and charcoal adsorber banks shall show >/= 99% DOP removal and >/= 99% halogenated hydrocarbon removal (penetration & bypass < 0.05%) or that filter train shall not be considered operable.

A.

5.5.7.c

b. The results of Laboratory (when obtained in accordance with Reg Guide 1.52 Section 6b) carbon sample analysis shall show >/= 95% radioactive methyl iodide removal at a velocity within 20% of system design, 0.5 to 1.5 mg/m3 inlet methyl iodine concentration, >/= 70% relative humidity and >/= 190 degrees F or that filter train shall not be considered inoperable.

A.

5.5.7.a and 5.5.7.b

~~c.~~ If gas flow capability or 8,000 CFM +/-800 CFM can not be provided to a filter train by the fans, that filter train shall not be considered operable.

4.7.B Standby Gas Treatment System

~~1.~~ 5.5.7 At least once per operating cycle, the following conditions shall be demonstrated.

see filter — A.8

5.5.7.d ~~a.~~ Pressure drop across the combined HEPA filters and charcoal adsorber banks is less than ~~8~~ 3.9 inches of water at approximately 8,000 (7200 to 8800) CFM.

M.1 A.

5.5.7.e ~~b.~~ Inlet heater is capable of providing at least 40 KW.

5.5.7.b, c — A.

5.5.7

2.a. The test and sample analysis of specification 3.7.B.2 shall be performed initially and at least once per year for standby service; or after every 720 hours of filter train operation; or following significant painting, fire or chemical release in any ventilation zone communicating with the system when it is in operation.

A.. when tested in accordance with Reg Guide 1.52, Sections 5c and 5d and ASME N510-1989 Sections 10 and 11

b. Cold DOP testing shall be performed after each complete or partial replacement of the HEPA filter bank or after any structural maintenance on the system housing. 5.5.7

c. Halogenated hydrocarbon refrigerant testing shall be performed after each complete or partial replacement of the charcoal adsorber bank or after any structural maintenance of the system housing. 5.5.7

A.11

B

d. Testing of gasket seals for housing doors downstream of the HEPA filters and charcoal adsorbers (ASME N510-1989 Section 6) shall be performed in conjunction with each test performed for compliance with Specification 4.7.B.2.a.

5.5.7.a and 5.5.7.b

~~4.9.A.1.2 (Continued)~~

5.5.9 Diesel Fuel Oil Testing Program

See Discussion of Changes for ITS 3.8.3, "Diesel Fuel Oil, Lube Oil and Starting Air"

See Discussion of Changes for ITS 3.8.1, "AC Sources - Operating"

c. By removing accumulated water:

1. From the day tanks least once per 31 days and after each occasion when the diesel is operated for greater than 1 hour, and

2. From the main storage tanks at least once per 31 days.

A1 applicable A3

5.5.9.a ~~d.~~ e. By sampling new fuel oil in accordance with ASTM ~~D4057-81~~ Standards prior to addition to the storage tanks and: R15 A1

5.5.9.a ~~1.~~ By verifying in accordance with the tests specified in ASTM ~~D975-81~~ prior to addition to the storage tanks that the sample has: R15

5.5.9.a.1 ~~a)~~ An API Gravity ~~of within 0.3 degrees at 60 degrees F~~ or a specific gravity ~~of within 0.0016 at 60/60 degrees F when compared to the supplier's certificate~~; or an absolute specific gravity ~~at 60/60 degrees F of greater than or equal to 0.83 but less than or equal to 0.89~~; or an API Gravity ~~at 60 degrees F of greater than or equal to 27 degrees but less than or equal to 39 degrees.~~ R15 R15 R15 R15

within limits A1

5.5.9 Diesel Fuel Oil Testing Program

5.5.9.a.2

~~b)~~ A kinematic ~~viscosity at 40 degrees C of greater than or equal to 1.9 centistokes but less than or equal to 4.1 centistokes, if~~ within limits for ASTM 2-D fuel oil (A1) when required (A1) ~~gravity was not determined by comparison with the supplier's certification.~~ (R15)

~~c)~~ A flash point ~~equal to or greater than 125 degrees F, and~~ (R15)

5.5.9.a.3

~~d)~~ A clear and bright appearance with proper color ~~when tested in accordance with ASTM D4176-82.~~ (R15)

(M13) or a water and sediment content within limits

5.5.9.b

~~2.~~ By verifying within 31 days of obtaining the sample that the other properties specified ~~in Table 1 of ASTM D975-81~~ for ASTM 2-D fuel oil (A1) are met ~~when tested in accordance with ASTM D975-81 except that the analysis for sulfur may be performed in accordance with ASTM D1552-79 or ASTM D2622-82.~~ (R15)

A

B

Specification 5.0

~~LIMITING CONDITION FOR OPERATION~~ A.

~~SURVEILLANCE REQUIREMENTS~~ A.

~~4.9.A.1.2 (Continued)~~ A. applicable

5.5.9 Diesel Fuel Oil Testing Program

5.5.9.c

e. At least once every 31 days by obtaining a sample of fuel oil from the storage tank in accordance with ASTM ~~D2276-78~~ Standards R15 A., and verifying that total particulate contamination is less than 10mg/liter when checked in accordance with ASTM D2276-78, Method A, except that the filters specified in ASTM ~~D2276-78, Sections 5.1.6 and 5.1.7~~ method A. R15, may have a nominal pore size of up to three (3) microns.

See Discussion of Changes for ITS 3.8.1, "AC Sources - Operating"

f. At least once per 18 months by:

1. Subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for this class of standby service.

g. At least once per 24 months by:

1. Verifying the diesel generator capability to reject a load of greater than or equal to that of the RHR Pump Motor for each diesel generator while maintaining voltage within 4160 ± 410 volts and frequency at 60 ± 1.2hz.

2. Verifying the diesel generator capability to reject an indicated load of 2400 kW-2600 Kw without tripping. The generator voltage shall not exceed the initial value (4160 ± 410 volts) by more than 660 volts during and following the load rejection.

Specification 5.0

5.6.7 ~~6.9.2.e~~ 6 (PAM Reports) (A1)

~~Unique Reporting Requirements~~

(B)

(A1) ~~Special reports shall be submitted to the NRC in accordance with 10 CFR 50.4 within the time period specified herein for each report. These reports shall be submitted covering the activities identified below pursuant to the requirements of the applicable reference specification.~~

~~a. Loss of shutdown margin, Specification 3.3.A and 4.3.A within 14 days of the event.~~

~~b. Reactor vessel inservice inspection, Specification 3.6.G and 4.6.G within 90 days of the completion of the reviews.~~

(R6) ~~c. Report seismic monitoring instrumentation inoperable for more than 30 days (Specification 3.15.B) within the next 10 working days. Submit a seismic event analysis (Specification 4.15.B) within 10 working days of the event.~~

~~d. Primary containment leak rate testing approximately three months after the completion of the periodic integrated leak rate test (Type A) required by Specification 4.7.A.2.c.2. For each periodic test, leakage test results from Type A, B and C tests shall be reported. B and C tests are local leak rate tests required by Specification 4.7.A.2.f. The report shall contain an analysis and interpretation of the Type A test results and a summary analysis of periodic Type B and Type C tests that were performed since the last Type A test.~~

(R13) ~~e. Calculated dose from release of radioactive effluents, Specification 3.8.B.2, 3.8.B.4, 3.8.C.2, 3.8.C.3, 3.8.C.5, 3.8.D, and 3.8.E.1.b.~~

(R6) ~~f. Sealed source leakage in excess of limits, Specification 3.13.2.~~

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(A4) When a report is required by condition B or F of LCO 3.3.3.1, Post Accident Monitoring Instrumentation, ..

Specification 5.0

~~in gaseous effluents (as determined by sampling frequency and measurement) shall be used for determining the gaseous pathway doses. Approximate methods are acceptable. The assessment of radiation doses shall be performed in accordance with the OFFSITE DOSE CALCULATION MANUAL (ODCM).~~

~~The Radiation Dose Assessment Report shall also include an assessment of radiation doses to the likely most exposed MEMBER OF THE PUBLIC from reactor releases and other nearby uranium fuel cycle sources (including doses from primary effluent pathways and direct radiation) for the previous calendar year to show conformance with 40 CFR Part 190, Environmental Radiation Protection Standards for Nuclear Power Operation. Guidance for calculating the dose contribution from liquid and gaseous effluents are given in Regulatory Guide 1.109, Revision 1, October 1977. If doses from plant effluents do not exceed twice the Appendix I limits, a statement to that effect shall constitute a 40 CFR 190 assessment.~~

R13

~~** In lieu of submission with the first half year Radioactive Effluent Release Report, the licensee will retain this summary of required meteorological data on site in a file that shall be provided to the NRC upon request.~~

M4

5.6.6 Add RCS Pressure and Temperature Limits Report

B

Specification 5.0

L6

B

PBAPS Unit 3

5.7 ~~6.13~~ **High Radiation Area**

As provided in paragraph 20.1601(c) of 10CFR Part 20, the following controls shall be applied to high radiation areas

~~6.13.1 In lieu of the "control device" or "alarm signal"~~ controls ~~required by paragraph 20.203(c)(2) of 10 CFR 20:~~ 20.1601(a) and (b)

5.7.1 a. Each High Radiation Area in which the intensity of radiation is greater than 100 mrem/hr but less than 1000 mrem/hr shall be barricaded, and conspicuously posted as a High Radiation Area and entrance thereto shall be controlled by issuance of a

b. Radiation Work Permit. Any individual ~~or group of individuals~~ permitted to enter such areas shall be

d. provided with ~~or accompanied by~~ one or more of the following:

Insert c.

STEP

or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures

Such areas may be ~~blocked during periods of entry and exit~~ opened as necessary of personnel or equipment

d.1 A radiation monitoring device which continuously indicates the radiation dose rate in the area.

d.2. A radiation monitoring device which continuously integrates the radiation dose rate in the area and alarms when a preset integrated dose is received. Entry into such areas with this monitoring device may be made

e. after the dose rate levels in the area have been established and personnel have been made knowledgeable of them.

Except for individuals qualified in radiation protection procedures,

Insert d.3

A direct reading dosimeter and, be under surveillance, as specified in the RWP or equivalent while in the area, of

d.4(a) ~~3.~~ An individual qualified in radiation protection procedures who is equipped with a radiation dose rate monitoring device. This individual shall be responsible for ~~providing positive control over activities within the area and shall perform periodic radiation surveillance at the frequency specified by the plant health physicist or his designee on the Radiation Work Permit.~~

at the work site

controlling personnel radiation exposure in the area

Insert d.4(b)

5.7.2 ~~b.~~ Each High Radiation Area in which the intensity of radiation is greater than 1000 mrem/hr shall be subject to ~~the provisions of 6.13.1 (a) above.~~ In addition, a locked door, shall be provided to prevent

Insert 5.7.2

a. unauthorized entry into such areas and the keys shall be maintained under the administrative

a.1 control of the ~~Shift Manager, the Shift Supervisor or the Senior Health Physicist.~~ radiation protection personnel

but less than 500 rads/hr

, gate or guard

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

B

Insert C

Individuals qualified in radiation protection procedures 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.

Insert d.3

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

Insert d.4(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.

Specification 5.0

L6

B

Insert 5.7.2

~~5.7.1~~ a. ~~Each High Radiation Area in which the intensity of~~
~~radiation is greater than 100 mrem/hr but less than~~
~~1000 mrem/hr shall be barricaded~~ and conspicuously
posted as a High Radiation Area and entrance
thereto shall be controlled by issuance of a
5.7.2 b. Radiation Work Permit. Any individual ~~or group of~~
Insert 5.7.2C. ~~individuals~~ permitted to enter such areas shall be
5.7.2 d. ~~provided~~ with or accompanied by one or more of the
following:

Such areas ~~may be bound during periods of entry and exit~~

or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures

~~5.7.1~~ ~~A radiation monitoring device which~~
~~continuously indicates the radiation dose rate~~
~~in the area.~~

5.7.2 d.1 ~~2.~~ A radiation monitoring device which
continuously integrates the radiation dose
rate in the area and alarms when a preset
integrated dose is received. Entry into such
Except for individuals qualified in radiation protection procedures, areas with this monitoring device may be made
5.7.2 e. after the dose rate levels in the area have
been established and personnel have been made
knowledgeable of them.

Insert 5.7.2.d.2 A direct-reading dosimeter and, be under surveillance, as specified in the RWP or equivalent ~~while in the area~~, or

5.7.2 d. ~~4~~ 3 (a) ~~3.~~ An individual, qualified in radiation
protection procedures who is equipped with a
radiation dose rate monitoring device. This
individual shall be responsible for ~~providing~~
~~positive control over activities within the~~
~~area and shall perform periodic radiation~~
~~surveillance at the frequency specified by the~~
~~plant health physicist or his designee on the~~
~~Radiation Work Permit.~~

~~at the work site~~

Insert 5.7.2 d. ~~4~~ 3 (b) controlling personnel radiation exposure in the area.

Insert 5.7.2. d. 4

Insert 5.7.2.d.4

4. A radiation monitoring and indicating device in those cases where the options of Specifications 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.

Insert 5.7.2.c

Specification 5.0

L6

B

Individuals qualified in radiation protection procedures 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.

Insert 5.7.2.d.~~3~~ 2

A radiation monitoring device that continuously transmits dose rate or cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area, with a means to communicate with and control every individual in the area or

Insert 5.7.2.d.~~4~~ 3 (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.

~~4.9.A.1.2 (Continued)~~

5.5.9 Diesel Fuel Oil Testing Program

See Discussion of Changes for ITS 3.8.3, "Diesel Fuel Oil, Lube Oil and Starting Air"

See Discussion of Changes for ITS 3.8.1, "AC Sources-Operating"

c. By removing accumulated water:

1. From the day tanks at least once per 31 days and after each occasion when the diesel is operated for greater than 1 hour, and

2. From the main storage tanks at least once per 31 days. A1

5.5.9.a ~~d~~ a. By sampling new fuel oil in accordance with Applicable ASTM ~~D4057-81~~ Standards prior to addition to the storage tanks and: R15 A1 B

5.5.9.a ~~1~~ 1. By verifying in accordance with the tests specified in ASTM ~~D975-81~~ prior to addition to the storage tanks that the sample has: R15

5.5.9.a.1 ~~a)~~ a) An API Gravity ~~of within 0.3 degrees at 60 degrees F~~ or a specific gravity ~~of within 0.0016 at 60/60 degrees F when compared to the supplier's certificate~~; or an absolute specific gravity ~~at 60/60 degrees F of greater than or equal to 0.83 but less than or equal to 0.89~~; or an API Gravity ~~at 60 degrees F greater than or equal to 27 degrees but less than or equal to 39 degrees.~~ within limits A1 R15 R16 R15 R15 A A A

5.5.9 Diesel Fuel Oil Testing Program

5.5.9.a.2

~~b)~~ A kinematic viscosity within limits for ASTM 2-D fuel oil (A1) ~~at 40 degrees C of greater than or equal to 1.9 centistokes but less than or equal to 4.1 centistokes~~ (R15), when required (A1) ~~, if gravity was not determined by comparison with the supplier's certification.~~ (R15)

~~e)~~ A flash point ~~equal to or greater than 125 degrees F, and~~ (R15)

5.5.9.a.3

~~d)~~ A clear and bright appearance with proper color ~~when tested in accordance with ASTM D4176-82.~~ (R15)

M13

or a water and sediment content within limits

5.5.9.b

~~2.~~ By verifying within 31 days of obtaining the sample that the other properties specified for ASTM 2-D fuel oil (A1) ~~in Table 1 of ASTM D975-81 are met when tested in accordance with ASTM D975-81 except that the analysis for sulfur may be performed in accordance with ASTM D1552-79 or ASTM D2622-82.~~ (R15)

Specification 5.0

~~LIMITING CONDITION FOR OPERATION~~ e (A1)

~~SURVEILLANCE REQUIREMENTS~~ e (A1)

~~4.9.A.1.2 (Continued)~~ e (A1)

applicable (A1)

5.5.9 Diesel Fuel Oil Testing Program

~~e.~~ 5.5.9.c At least once every 31 days by obtaining a sample of fuel oil from the storage tank in accordance with applicable ASTM Standards ~~D2276-78~~ (R15), and verifying that total particulate contamination is less than 10mg/liter when checked in accordance with ASTM ~~D2276-78~~ method, Method A, except that the filters specified in ASTM ~~D2276-78, Sections 5.1.6 and 5.1.7,~~ (R15) may have a nominal pore size of up to three (3) microns. (A1)

See Discussion of Changes for ITS 3.8.1, "AC Sources - Operating"

f. At least once per 18 months by:

1. Subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for this class of standby service.

g. At least once per 24 months by:

1. Verifying the diesel generator capability to reject a load of greater than or equal to that of the RHR Pump Motor for each diesel generator while maintaining voltage within 4160 ± 410 volts and frequency at 60 ± 1.2hz.

2. Verifying the diesel generator capability to reject an indicated load of 2400 kW-2600 Kw without tripping. The generator voltage shall not exceed the initial value (4160 ± 410 volts) by more than 660 volts during and following the load rejection.

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TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

M_5 This change proposes to add the requirement that procedures be established, implemented, and maintained for all programs identified in Specification 5.5 "Programs and Manuals." The addition of the requirement that procedures be established, implemented, and maintained for the programs of Section 5.5 is consistent with the requirement for these programs. The addition of requirements in the TS constitutes a more restrictive change. This change is consistent with NUREG-1433.

M_6 The SGT System filter delta P limit has been decreased from 8 inches water gauge to 3.9 inches water gauge. This ensures that at the maximum allowed filter train flow rate (10500 cfm allowed per SR 3.6.4.1.4), the filter train delta P will be limited such that filter train integrity is not compromised. Since the limit has been decreased, this constitutes a more restrictive change.

M_7 Not used. 6

M_8 This change proposes to add a requirement in the TS for the Safety Function Determination Program. This program is included to support implementation of the support system Operability characteristics of the improved Technical Specifications. The addition of new requirements to the TS constitutes a more restrictive change.

M_9 This change proposes to add a requirement in the TS for Technical Specifications Bases Control Program. This program is provided to specifically delineate the appropriate methods and reviews necessary for a change to the Bases of Technical Specifications.

M_{10} This change proposes to add a requirement in TS for a Component Cyclic or Transient Limit Program. This program provides controls to track the cyclic and transient occurrences to ensure that components are maintained within the design limits. The addition of programs to the TS, constitutes a more restrictive change. This change is consistent with NUREG-1433.

M_{11} This change proposes to add a requirement in Technical Specifications to establish, implement, and maintain procedures covering Quality Assurance for effluent monitoring. This change will ensure that adequate quality assurance is maintained when monitoring effluents. This change adds additional requirements to Technical Specifications which constitutes a more restrictive change. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

M_{12} This change proposes to add a requirement in Technical Specifications for the Plant Manager, or his designee, to approve prior to implementation, each proposed test, experiment or modification to systems or equipment that affect nuclear safety. This change ensures the Plant Manager, or his designee, is aware of all changes with the potential to affect nuclear safety. This change adds additional requirements to Technical Specifications which constitute a more restrictive change. This change is consistent with NUREG-1433.

M_{13} The current Specifications utilize the ASTM D4176-82 clear and bright test to provide a qualitative assessment of the acceptability of new diesel fuel oil with regard to water and sediment content. The ASTM clear and bright test is a visual check for evidence of water and particulate contamination performed after drawing a fuel oil sample for field testing. The visual check is accomplished by swirling the sample so a vortex is formed. Sediment and water will accumulate on the bottom of the container directly beneath the vortex and very fine suspended solids or water will render the product hazy. The ASTM clear and bright test should only be used for fuel oil meeting the color requirements of ASTM D4176-82 (ASTM color of 5 or less). ASTM D4176-82 does not recommend the clear and bright test be performed on fuels darker than ASTM 5 since the presence of free water or particulates could be obscured. The intentional addition of dyes to fuel oil by suppliers (such as to identify sulfur content) makes the fuel oil darker than ASTM 5 and results in the need to use another method for determining water and sediment content of the fuel oil. To address the method for determining the presence of water and sediment in new diesel fuel oil that has been dyed, the requirements of Specification 5.5.9 (Diesel Fuel Oil Testing Program) and the Bases for SR 3.8.3.3 are proposed to be revised to allow the use of the ASTM D975-81 water and sediment by centrifuge test in lieu of the ASTM D4176-82 clear and bright test. The Bases for SR 3.8.3.3 will also be revised to reflect the use of the ASTM water and sediment by centrifuge test when dyes have intentionally been added to new fuel oil. B

This change provides an alternate test for verifying the acceptability of new fuel oil with regard to water and sediment content. Excessive water and sediment in diesel fuel oil could have an immediate detrimental impact on diesel engine combustion and as a result diesel generator OPERABILITY. The ASTM D975-81 water and sediment by centrifuge test provides a quantitative assessment of water and sediment content. The use of the ASTM water and sediment

TECHNICAL CHANGES - MORE RESTRICTIVE

M_{13} (cont'd) by centrifuge test ensures that excessive water and sediment content, in new diesel fuel oil that has been dyed, will be detected (and not obscured by the presence of the dye) prior to addition to the storage tanks. The sensitivity of the ASTM water and sediment by centrifuge test for water and sediment is not affected by the presence of dyes in the fuel oil. For fuel oil with dyes, the sensitivity for detection of water and sediment of the ASTM water and sediment by centrifuge test is better than that provided by the ASTM clear and bright test. The ASTM water and sediment by centrifuge test is also the same test performed to quantitatively determine water and sediment content within 31 days following sampling and addition (after the new fuel has been added to the storage tank) in accordance with Specification 5.5.9.b and the Bases for SR 3.8.3.3. Regulatory Guide 1.137, Fuel Oil Systems for Standby Diesel Generators, also identifies that the water and sediment by centrifuge test provides an acceptable method for ensuring the initial and continuing quality of diesel fuel oil with respect to water and sediment content. Therefore, this alternate test provides adequate assurance, prior to storage tank addition, that the water and sediment content of the new dyed fuel oil will maintain diesel generator OPERABILITY. This change is considered to be more restrictive since the ASTM water and sediment by centrifuge test provides a quantitative assessment of water and sediment content rather than the qualitative assessment of water and sediment content provided by the ASTM clear and bright test. In addition, the ASTM water and sediment by centrifuge test takes more time to perform and is more difficult to perform than the ASTM clear and bright test. However, as previously discussed, this change is necessary to assure the presence of dyes in fuel oil will not affect the capability to detect water and sediment in the fuel oil.

TECHNICAL CHANGES - RELOCATIONS

R_1 PECO Energy proposes the Minimum Shift Crew Composition Table not be retained in Technical Specifications. 10 CFR 50.54(k), (l), and (m) provide the requirements for the shift complement regarding licensed operators. The regulations describe the minimum shift composition for operating modes, as well as cold shutdown and refueling. Additionally, Specifications 5.1.2 and 5.2.2.c of the improved Technical Specifications specify the conditions when the licensed operator is required to be in the control room. Non-licensed operator requirements will be maintained in Specification 5.2.2.a.

TECHNICAL CHANGES - RELOCATIONS

R_1 (cont'd) Removing the Table from Technical Specifications will not jeopardize plant safety nor is it necessary to be duplicated in order to assure safe operation of the facility. These requirements will also be included in plant procedures.

R_2 PECO Energy proposes the requirement for an SRO to be present during fuel handling and to supervise all core alternations not be retained in Technical Specifications. Duplication of the regulation provided in 10 CFR 50.54(m)(2)(iv) is not necessary to assure safe operation of the facility. The current regulation states,

> "Each licensee shall have present, during alteration of the core of a nuclear power unit (including fuel loading or transfer), a person holding a senior operator license or a senior operator license limited to fuel handling to directly supervise the activity and, during this time, the licensee shall not assign other duties to this person."

R_3 Technical Specifications need not require an administrative letter be issued to station personnel on an annual basis describing the responsibility of the Shift Supervisor. The organization and responsibilities of each function are adequately described in the UFSAR. As a result, this requirement may be relocated to the UFSAR or appropriate plant procedures. Plant safety is not compromised by this proposed change.

R_4 PECO Energy proposes that the review and audit functions, ISEG requirements, Reportable Event interval review requirements, requirements for procedures that meet ANSI N18.7-1972, the requirement that procedures covering Quality Assurance for environmental monitoring use the guidance in Regulatory Guide 4.1, Revision 1, and the Fire Protection Inspections (performed under the audit function of the NRB) be relocated from Technical Specifications on the basis that they can be adequately addressed elsewhere and that there is adequate regulatory authority to do so.

Thus, the provisions are not necessary to assure safe operation of the facility, given the existence of these redundant requirements. This proposal would rely on a Quality Assurance Program implementing 10 CFR 50.54 and 10 CFR 50, Appendix B, the UFSAR, or appropriate procedures to control the requirements. Such an approach would result in an equivalent level of regulatory authority while providing for a more appropriate change control process. The level

TECHNICAL CHANGES - RELOCATIONS

R_4 (cont'd) of safety of facility operation is unaffected by the change and NRC and PECO Energy resources associated with processing license amendments for these Administrative Control requirements will be optimized. The following points summarize PECO Energy's position on removing these requirements from Technical Specifications.

The on-site review function, composition, alternate membership, meeting frequency, quorum, responsibilities, authority, and records are all covered in equivalent detail in ANSI N18.7-1972. These requirements are also proposed to be covered in the QA Program, UFSAR, or appropriate procedures and equivalent change control is provided by 10 CFR 50.54(a) or 10 CFR 50.59.

The off-site review group is also addressed, although with less detail, in ANSI N18.7-1972. The QA Program, UFSAR, or appropriate procedures will include the requirements for the off-site review group. Since the offsite review group provides after-the-fact recommendations to improve activities, this organization is not necessary to assure safe operation of the facility. Based upon these considerations, duplication of these requirements in the Technical Specifications is unnecessary.

Audit requirements are specified in the QA Program to satisfy 10 CFR 50, Appendix B, Criterion XVIII. Audit requirements are also covered by ANSI N18.7, ANSI N45.2, 10 CFR 50.54(t), 10 CFR 50.54(p), and 10 CFR 73. Therefore, duplication of the requirements contained in the above documents in the Administrative Controls Section of the Technical Specifications does not enhance the level of nuclear safety for the unit. Therefore, the provisions relating to audits are not necessary to assure safe operation of the facility.

Relocating ISEG requirements, Reportable Event interval review requirements, requirements for procedures that meet ANSI N18.7-1972, the requirement that procedures covering Quality Assurance for environmental monitoring use the guidance in Regulatory Guide 4.1, Revision 1, and the Fire Protection Inspection requirements to the QA Program or UFSAR will ensure these requirements are appropriately maintained. The change control process of 10 CFR 50.54(a) for the QA Program or 10 CFR 50.59 for the UFSAR will provide equivalent change control.

TECHNICAL CHANGES - RELOCATIONS (continued)

R_5 PECO Energy proposes the requirements on training may be deleted from Technical Specifications on the basis that they are adequately addressed by other Section 5.0 administrative controls as well as regulations. Improved Technical Specification Section 5.3, Unit Staff Qualifications, provides adequate requirements to assure an acceptable, competent operating staff. Each member of the unit staff shall meet or exceed the minimum qualifications of specific Regulatory Guides or ANSI Standards acceptable to the NRC staff. Section 5.3 of the improved Technical Specifications describes the details of the required qualifications.

Additionally, improved Technical Specification Section 5.2, Organization, details unit staff requirements. Section 5.2.2.a and 5.2.2.b, and 10 CFR 50.54 describe the minimum shift crew composition and delineates which positions require an RO or SRO license. Training and requalification of those positions are as specified in 10 CFR 55.

Based upon these considerations, duplicating the provisions relating to training is not necessary to assure operation of the facility in a safe manner and may be relocated to a licensee controlled document.

R_6 This change proposes to relocate the requirements for the Loss of Shutdown Margin Report, the Reactor Vessel Inservice Inspection Report, the Seismic Monitoring Instrumentation Inoperability Report, the Primary Containment Leak Rate Testing Report, the Sealed Source Leakage Report, and information contained in the Bases for Post Accident Sampling to plant procedures or another licensee controlled document (e.g., UFSAR). Any changes to these requirements will require a 10 CFR 50.59 evaluation. This change is consistent with NUREG-1433.

R_7 This change proposes to relocate the requirements for Reportable Event Action out of TS. These requirements are duplicated in 10 CFR 50.73. These requirements will be relocated to plant procedures or other licensee controlled documents. The NRC and Industry have agreed to remove requirements from the Administrative Controls Section which are duplicated in other regulatory requirements. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS (continued)

R_8 This change proposes to relocate the requirements which state where to send NRC Reports, Program Revisions, etc., out of TS. These requirements will be relocated to plant procedures or other licensee controlled documents. These requirements are duplicated in 10 CFR 50.4. The NRC and Industry have agreed to remove requirements from the Administrative Controls Section which are duplicated in other regulatory requirements. This change is consistent with NUREG-1433.

R_9 This change proposes to relocate the requirements for solid waste reporting requirements to the Process Control Program (PCP). The PCP is described in appropriate plant procedures. These items are relocated to the PCP per GL 89-01 which allowed RETS to be relocated from TS. The PCP implements the requirements of 10 CFR 20, 10 CFR 61, and 10 CFR 71. For more details reference change L_1 for CTS 3/4.8, "Radioactive Materials." This change is consistent with NUREG-1433.

R_{10} This change proposes to relocate the requirements for the Radiation Protection Program and the Iodine Monitoring Program out of Technical Specifications. When evaluating these programs, PECO Energy relied upon a focussed interpretation of the terminology "operation of the facility in a safe manner" for determining whether a program need be retained in the Technical Specifications. PECO Energy interpreted this phrase to mean provisions necessary to ensure reactor safety. In other words, safe manner was assessed relative to nuclear safety. Such an interpretation is consistent with previous regulatory interpretations; most recently, the Commissions Final Policy Statement on Technical Specification Improvement. The Policy Statement, in part, defined the criteria for determining what is necessary to be included within the scope of Technical Specifications. From the Summary of the Policy Statement:

> "The Policy Statement identifies four criteria for defining the scope of Technical Specifications. The criteria were intended to be consistent with the scope of Technical Specifications as stated in the Statement of Consideration accompanying the current rule, 10 CFR 50.36. The Statement of Consideration for the final rule issuing 10 CFR 50.36 (33 FR 18610, December 17, 1968) discusses the scope of Technical Specifications as including the following:

TECHNICAL CHANGES - RELOCATIONS

R_{10} (cont'd)

"In the revised system, emphasis is placed on two general classes of technical matters: (1) those related to prevention of accidents, and (2) those related to mitigation of the consequences of accidents. By systematic analysis and evaluation of a particular facility, each applicant is required to identify at the construction permit stage, those items that are directly related to maintaining the integrity of the physical barriers designed to contain radioactivity. Such items are expected to be the subjects of Technical Specifications in the operating license.""

The Summary Statement for the Policy Statement continues:

"Since many of the requirements are of immediate concern to the health and safety of the public, (the principal operative standard in Section 182a. of the Atomic Energy Act) this Policy Statement adopts, for the purpose of relocating requirements from Technical Specifications to the licensee-controlled documents, the subjective statement of the purpose of Technical Specifications expressed by the Atomic Safety and Licensing Appeal Board in Portland General Electric Company (Trojan Nuclear Plant), ALAB-531, 9 NRC 263 (1979). There, the Appeal Board interpreted Technical Specifications as being reserved for those conditions or limitations upon reactor operation necessary to obviate the possibility of an abnormal situation or event giving rise to an immediate threat to the public health and safety."

The preceding interpretation was provided by the NRC to more clearly define the scope of Technical Specifications, in particular, with respect to limiting conditions for operation (10 CFR 50.36(c)(2)). The wording of 10 CFR 50.36 (c)(2) once again focusses on equipment "required for safe operation of the facility." Thus, defining this same phrase within the context of 10 CFR 50.36(c)(5) in a similar manner would appear to be consistent and appropriate.

The following is the individual evaluation of the programs to be relocated.

TECHNICAL CHANGES - RELOCATIONS

R_{10} (cont'd)

* Radiation Protection Program

The Radiation Protection Program (6.11) requires procedures to be prepared for personnel radiation protection consistent with the requirements of 10 CFR 20. These procedures are developed to ensure nuclear plant personnel safety and have no impact on nuclear safety. Additionally, nuclear plant personnel are not 'members of the public.' Thus, the principal operative standard in Section 182a. of the Atomic Energy Act; 'health and safety of the public' does not apply. Based on these considerations, the Radiation Protection Program administrative control is not necessary to assure operation of the facility in a safe manner and can be relocated from Technical Specifications to the UFSAR. The requirement to have procedures to implement Part 20 is also contained within 10 CFR 20.1101(b). Periodic review of these procedures is addressed under 10 CFR 20.1101(c).

* Iodine Monitoring Program

The Iodine Monitoring Program provides controls to ensure the capability to accurately determine the airborne iodine concentration in vital areas under accident conditions. This program was developed to minimize radiation exposure to plant personnel post-accident and has no impact on nuclear safety. Additionally, nuclear plant personnel are not 'members of the public.' Thus, the principal operative standard in Section 182a. of the Atomic Energy Act; 'health and safety of the public' does not apply. Based on these considerations, the Iodine Monitoring Program administrative control is not necessary to assure operation of the facility in a safe manner and can be relocated from Technical Specifications to the UFSAR.

R_{11} PECO Energy proposes to address the review and approval process and the temporary change process for procedures as part of the QA Program, UFSAR, or appropriate procedures. This proposal is based on the existence of the following requirements which are duplicative of 10 CFR 50.36 in these areas and which assure operation of the facility in a safe manner. The requirement for procedures is mandated by 10 CFR 50, Appendix B, Criterion II (second sentence) and Criterion V. ANSI N18.7-1972, which is an NRC staff-endorsed document used in the development of the QA Program, also contains specific requirements related to procedures.

TECHNICAL CHANGES - RELOCATIONS

R_{11} (cont'd)

ANSI N18.7-1972, Section 5.2.2 discusses procedure adherence. This section clearly states that procedures shall be followed, and the requirements for use of procedures shall be prescribed in writing. ANSI N18.7-1972 also discusses temporary changes to procedures, and requires review and approval of procedures to be defined.

ANSI N18.7-1972, Section 5.2.15 describes the review, approval and control of procedures. The section describes the requirements for the licensee's Quality Assurance Program to provide measures to control and coordinate the approval and issuance of documents, including changes thereto, which prescribe all activities affecting quality. The section further states that each procedure shall be reviewed and approved prior to initial use. The reviews required are also described.

ANSI N45.2-1971, Section 6 also requires the Quality Assurance Program to describe procedure requirements.

PECO Energy can continue to implement the requirements of 10 CFR 50, Appendix B, regarding procedures without duplicating the necessity of procedure requirements in the facility Technical Specifications. Safe operation of the plant will continue to be maintained, and therefore, the requirements for procedures and their control should not be re-addressed in Technical Specifications. Duplication of the provisions related to procedures is not necessary to assure safe operation of the facility.

R_{12}

The requirement to submit a Startup Report has been relocated from the PBAPS TS. The report is a summary of plant startup and power escalation testing following receipt of the Operating License, increase in licensed power level, installation of nuclear fuel with a different design or manufacturer than the current fuel, and modifications that may have significantly altered the nuclear, thermal, or hydraulic performance of the unit. The report provided a mechanism for NRC to review the appropriateness of licensee activities after-the-fact, but provided no regulatory authority once the report was submitted (i.e., no requirement for Commission approval). The approved 10 CFR 50, Appendix B, Quality Assurance Program and Startup Test Program provide assurance the listed activities are adequately performed and that appropriate corrective actions, if required, are taken.

TECHNICAL CHANGES - RELOCATIONS

R_{12} (cont'd) Given that the report was required to be provided to the Commission no sooner than 90 days following completion of the respective milestone, report completion and submittal was clearly not necessary to assure operation of the facility in a safe manner for the interval between completion of the startup testing and submittal of the report. Additionally, given there is no requirement for the Commission to approve the report, then the Startup Report is not necessary to assure operation of the facility in a safe manner.

Based on these considerations, the Startup Report may be removed from Technical Specifications and relocated to a licensee controlled document.

R_{13} This change proposes to relocate the requirements for major changes to the Radioactive Waste Treatment Systems, the Radiation Dose Assessment Report, and specific details for the Radiological Environmental Operating Report and the Radioactive Effluent Release Report, as well as the submittal requirements for these reports and programs, to the Offsite Dose Calculations Manual (ODCM). These items are relocated to ODCM per GL 89-01 which allowed Radiological Effluent Technical Specifications to be relocated from TS. For more details reference change L_1 for CTS 3/4.8, "Radioactive Materials." This change is consistent with NUREG-1433.

R_{14} PECO Energy proposes the requirements on record retention may be deleted from Technical Specifications on the basis that they can be adequately addressed by the QA Program (10 CFR 50, Appendix B, Criterion XVII) and because provisions relating to record keeping do not assure operation of the facility in a safe manner.

Facility operations are performed in accordance with approved written procedures. Areas include normal startup, operation and shutdown, abnormal conditions and emergencies, refueling, safety-related maintenance, surveillance and testing, and radiation control. Facility records document appropriate station operations and activities. Retention of these records provides document retrievability for review of compliance with requirements and regulations. Post-compliance review of records does not assure operation of the facility in a safe manner as activities described in these documents have already been performed. Numerous other regulations such as 10 CFR 20, Subpart L, and 10 CFR 50.71 also require the retention of certain records related to operation of the nuclear plant.

TECHNICAL CHANGES - RELOCATIONS (continued)

R_{15} Existing Specification 4.9.A.1.2.d and 4.9.A.1.2.e identify the requirements for testing new and stored diesel fuel oil. Proposed Specification 3.8.3, Diesel Fuel Oil, Lube Oil, and Starting Air, requires that diesel fuel be tested in accordance with proposed Specification 5.5.9, Diesel Fuel Oil Testing Program, which lists the diesel fuel oil tests required and the applicable ASTM Standards. Descriptions of test performance and acceptance criteria for the required fuel oil tests that are contained in the ASTM Standards are no longer listed in the Technical Specifications but have been relocated to the Bases of proposed Specification 3.8.3 and to plant procedures. Placing these details in the Bases and plant procedures, and the addition of the referenced ASTM Standards of the Diesel Fuel Oil Testing Program in Technical Specifications, provides assurance they will be maintained. Changes to the Bases and plant procedures are controlled so that the information will not be changed without a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_{16} Existing Specification 3.8.C.6 identifies the requirements for monitoring explosive gas downstream of the Off-Gas Recombiners. Proposed Specification 5.5.8, Explosive Gas Monitoring Program, will require that explosive gas concentration limits and a surveillance program for these limits be maintained. However, specific details regarding the explosive gas concentration limits and associated surveillance program are being relocated to plant procedures. Placing these details in the plant procedures, and the addition of the Explosive Gas Monitoring Program to Technical Specifications provides assurance they will be maintained. Changes to the plant procedures are controlled so that the information will not be changed without a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_{17} Existing Specification 6.9.1.c requires that all challenges to the primary coolant system safety and relief valves be reported to the NRC on an annual basis. This requirement is being relocated to plant procedures. The report provides a mechanism for the NRC to obtain information regarding challenges to safety and relief valves after-the-fact, but provides no regulatory authority once the report is submitted (i.e., no requirement for NRC approval). Given that the report is only required to be provided annually to the NRC and is not required to be approved by the NRC, it is clearly not necessary to assure operation of the facility in a safe manner.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_1 This change proposes to relax the requirement to have an individual qualified in radiation protection procedures to be onsite when fuel is in the reactor. The proposed change will allow the position to be vacant for up to two hours in order to provide for unexpected absence, provided immediate action is taken to fill the required position. This change will not have any impact on plant safety because the presence of a person qualified in radiation protection procedures is not required for the mitigation of any accident. The only impact may be if entries into radiation areas are required to repair equipment. However, this impact will be slight because the allowed outage time of equipment is usually longer than 2 hours, the chance of a problem occurring within the 2 hour period this position is unfilled is small, and the probability that the position will be unfilled (since usually more than one person qualified in radiation protection procedures is located on site) is small. This change is consistent with NUREG-1433.

L_2 This change proposes to relax the requirement for submitting the Occupational Exposure Report. The current TS require the report to be submitted by March 1 of each year. This proposed change will allow the report to be submitted by March 31 of each year. Given that the report is still required to be provided to the NRC on or before March 31 and covers the previous calendar year, report completion and submittal is clearly not necessary to assure operation in a safe manner for the interval between March 1 and March 31. Additionally, there is no requirement for the NRC to approve the report. Therefore, this change has no impact on the safe operation of the plant. This change is consistent with NUREG-1433.

L_3 The requirements of 10 CFR 50.55a(g) currently require inservice testing of the PBAPS ASME Code Class 1, 2, and 3 pumps and valves. NRC Generic Letter 89-04 states that if these pumps are within the Required Action range or the valves exceed the limiting full stroke time value, the associated component must be declared inoperable and the applicable Technical Specification Actions entered. Inservice Testing Program requirements are addressed in Improved Technical Specifications consistent with this philosophy. This change proposes to apply SR 3.0.2 (allowing an extension of 1.25 times the Surveillance interval) and SR 3.0.3 (allowing 24 hours to perform the Surveillance if missed) to the Inservice Testing frequencies. Currently, the requirements of SR 3.0.2 and SR 3.0.3 are not utilized in the Inservice Test Program test frequencies. The change

TECHNICAL CHANGES - LESS RESTRICTIVE

L_3 (cont'd) also adds a requirement that the ASME Boiler and Pressure Vessel Code requirements will not supersede the requirements of any TS. The 25% extension facilitates Surveillance scheduling and considers plant operating conditions that may not be suitable for conducting the Surveillance (e.g., transient conditions or other ongoing Surveillance or maintenance activities). The utilization of the 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements. The utilization of the 24 hour delay period allows adequate time to complete a Surveillance that has been missed. The basis for this delay period includes consideration of unit conditions, the time required to perform the surveillance, the safety significance of the delay in completing the required surveillances, and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the requirements. This change is consistent with NUREG-1433.

L_4 Generic Letter No. 82-12 provided licensees with an NRC policy statement concerning the factors causing fatigue of operating personnel at nuclear reactors. This policy statement concluded that licensees of operating plants shall establish controls to prevent situations where fatigue could reduce the ability of operating personnel to keep the reactor in a safe condition. The controls should focus on shift staffing and the use of overtime that influences fatigue. The objective of the controls would be to assure that, to the extent practical, personnel are not assigned to shift duties while in a fatigued condition that could significantly reduce their mental alertness or their decision making capabilities. These controls apply to the plant staff who perform safety related functions.

Generic Letter No. 82-16 supplemented the policy statement by providing licensees with sample Technical Specifications that limit the amount of overtime worked by plant staff performing safety related functions.

The current additional restrictions for the shift operators were based on guidance provided in NUREG/CR-4248. However, this guidance was never formally adopted into a revised policy statement.

TECHNICAL CHANGES - LESS RESTRICTIVE

L_4 (cont'd) The guidance provided in Generic Letter No. 82-12, as supplemented by Generic Letter No. 82-16, is the current NRC policy regarding overtime work restrictions and has been adopted by many operating reactors. Although the proposed changes relax overtime work restrictions for shift operators, the guidance of Generic Letters Nos. 82-12 and 82-16 will ensure that adequate levels of safety are maintained as demonstrated by the use of this guidance throughout the nuclear industry.

In the case of the remaining individuals who perform safety related functions, overtime restrictions are not relaxed.

Management oversight for all individuals who perform safety related functions, which includes shift operators, will be maintained in that the Plant Manager, or personnel designated in administrative procedures, will continue to monitor the shift overtime. Additionally, individual overtime will be monitored by the Plant Manager, or the appropriate designated personnel, on a monthly basis.

In the case of control room operators, additional initiatives have been taken to reduce fatigue. These initiatives include:

(a) moving a greater portion of workload to the weekend backshifts which has reduced the workload during the week,

(b) an enhanced fitness for duty program in which supervisors have been trained in recognizing the appropriate fitness for duty,

(c) an improved performance management process which will ensure employee accountability,

(d) and, improved planning of maintenance activities to reduce overtime.

Therefore, PECO Energy is proposing to relax restrictive working hour limits for shift operators contained in PBAPS Technical Specification Section 6.20, "Site Staff Working Hour Restrictions," and revise the wording in Section 6.20 and delete its Bases (current page 272) to conform with the guidance of Generic Letter No. 82-16 and NUREG-1433.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L_5 The proposed change will revise the requirement for the Senior Manager-Operations to hold a Senior Reactor Operator (SRO) license. The change will require the Senior Manager - Operations to either hold an SRO license or have held an SRO license on a similar BWR unit. However, shift personnel would continue to report to the Shift Managers who are required to be licensed as SROs for PBAPS, in accordance with 10 CFR 50.54 (m)(2), and who in turn report directly to the Senior Manager-Operations.

L_6 Existing Specification 6.13, which provides high radiation area access control alternatives pursuant to 10 CFR 20.203(c)(2) (revised 10 CFR 20.1601(c)), has been significantly revised as a result of the changes to 10 CFR 20, the guidance provided in Regulatory Guide 8.38 (Control of Access to High and Very High Radiation Areas in Nuclear Power Plants), and current industry technology in controlling access to high radiation areas. The changes include a capping dose rate to differentiate a high radiation area from a very high radiation area, additional requirements for groups entering high radiation areas, and clarification of the need for communication and control of workers in high radiation areas. This change provides acceptable alternate methods for controlling access to high radiation areas. As a result, this change will not decrease the ability to provide control of exposures from external sources in restricted areas.

DISCUSSION OF CHANGES
ITS 5.0: ADMINISTRATIVE CONTROLS BASES

The Bases of the current Technical Specifications for this section (pages 269 and 272) have been deleted since the ITS does not have any Bases for Chapter 5.0. This is consistent with NUREG-1433. In addition, pages 245a, 254a, 254b, and 257a, which are blank pages, have been deleted.

ADMINISTRATIVE CHANGES

(A_1, A_2, A_3, A_4, A_5, A_6, A_7, A_8, A_9, A_{10}, A_{11}, A_{12}, A_{13}, A_{14}, A_{15}, A_{16}, A_{17}, A_{18}, and A_{19} Labeled Comments/Discussions for ITS 1.0) - continued

A_{15} The requirements specified by the definition of Surveillance Frequency is moved to the PBAPS ITS Section 3.0, Surveillance Requirement (SR) Applicability. The requirements were reworded and incorporated into this section. This is an administrative change because the requirements are being moved to another TS, the change has no impact on any other definition, it does not change the intent of any Technical specification. Any technical change will be justified in the change package for Section 3.0. This change maintains the consistency between the PBAPS ITS and BWR/4 STS.

The table portion (Frequency notation versus specific time in hours, days, or months) of the Surveillance Frequency definition is being deleted because the SR Frequencies in the PBAPS ITS do not use notation. The Frequencies for the SR lists the specific number of hours, days, or months (e.g.,instead of M--for Monthly, the PBAPS ITS will list 31 days).

The section in the frequency definition which states, "A surveillance test of the DGs that requires a plant outage may be deferred beyond the calculated due date until the next refueling outage, provided the equipment has been similarly tested and meets the surveillance requirement for the other unit" will be addressed in the discussion of changes for ITS Section 3.8, Electrical Power Systems.

A_{16} Nine definitions are added to the PBAPS ITS. These definitions were added for consistency with the BWR/4 STS. These definitions are used throughout the PBAPS ITS and in the current PBAPS TS. The defined terms are used in the LCOs, SRs, and Bases of the TS and were defined for the convenience of the users of the TS. The inclusion of these definitions are deemed administrative and have no impact on their own. If the added definitions are used in new requirements (which is a technical change) the discussion of changes for the individual sections of the TS will provide the justification.

A_{17} The following sections are being added to the TS. These additions aid the understanding and use of the new standard TS format and style of presentation. Some conventions in applying the TS to unique situations have previously been the subject of debate and

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, M_3, M_4, M_5, M_6, M_7, and M_8 Labeled Comments/Discussions for ITS 3.1.3) - continued

M_3 Currently, if a stuck control rod (not fully inserted) requires that the reactor be in Cold Shutdown (Mode 4), 48 hours is provided to shut down the unit (existing Specification 3.3.2.a). The proposed Action (ACTION E) requires the reactor to be in Hot Shutdown (Mode 3) within 12 hours instead of the currently required Cold Shutdown in 48 hours. This change is more restrictive because all rods must be fully inserted in 12 hours instead of 48 hours. Cooling the unit down (proceeding from Mode 3 to Mode 4) does not provide any additional margin and, in some cases, could be counter productive since positive reactivity is inserted during a cooldown.

M_4 Currently, LCO 3.3.A.2.c provides an exception for the required actions for an inoperable control rod if the reason for inoperability is scram time > 7 seconds and the rod can be inserted with drive pressure.

The proposed requirement for declaring a rod inoperable because scram time exceeds 7 seconds (SR 3.1.3.4) requires that a rod be declared inoperable. Therefore, under the proposed change a rod with a scram time greater than 7 seconds must be fully inserted and disarmed in accordance with LCO 3.1.3 Condition C. This is more restrictive than the existing requirement which would allow the slow rod to remain withdrawn and armed.

M_5 Currently, LCO 3.3.A.2.e requires that a control rod whose position cannot be positively determined is inoperable; however, there is no requirement to periodically verify the position of each rod. This requirement has been modified to require the position of each control rod to be verified every 24 hours (proposed SR 3.1.3.1).

M_6 Existing Specification 3.3.A.2.f requires that inoperable (and stuck) control rods be positioned such that SDM requirements (3.3.A.1) are maintained.

The proposed required actions for LCO 3.1.3 require that: with one stuck rod (Required Action A.4) that SDM be verified within 72 hours (see L_4); with more than one stuck rod (Required Action B.1) that the reactor be in Hot Shutdown within 12 hours; and, with one or more inoperable rods (Required Action C.1) that each inoperable rod be fully inserted. B

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, M_3, M_4, M_5, M_6, M_7, and M_8 Labeled Comments/Discussions for ITS 3.1.3)

M_6 (cont'd) By allowing only one stuck rod, and by requiring that all inoperable rods be fully inserted, proposed Required Actions A.4, B.1, and C.1 provide greater assurance that SDM is maintained then the requirement for verifying SDM for multiple rods that remain withdrawn. B

M_7 The current time to reach a non-applicable condition has been reduced from 24 hours to reach Cold Shutdown (MODE 4) to 12 hours to reach MODE 3 (per proposed Required Action E.1). This change is more restrictive because all rods must be fully inserted in 12 hours instead of the currently required 24 hours. Cooling the unit down (proceeding from MODE 3 to MODE 4) does not provide any additional margin and, in some cases, could be counter productive since positive reactivity is inserted during a cooldown.

M_8 Existing requirement SR 4.3.B.1.b requires that rod coupling be verified "when the rod is fully withdrawn the first time after each refueling outage." The proposed SR 3.1.3.5 requires this coupling check each time the rod is fully withdrawn. This change is in accordance with the recommendations in BWR Standard Technical Specifications, NUREG-1433, and incorporates an easily implemented good practice.

(M_1, M_2, and M_3 Labeled Comments/Discussions for ITS 3.1.4)

M_1 The proposed change provides a different method to determine if measured scram insertion times are sufficient to insert the amount of negative reactivity assumed in the accident and transient analyses. A description and supporting analysis for the proposed method is contained in BWROG-8754, letter from R.F. Janecek (BWROG) to R. W. Starostecki (NRC), dated September 17, 1987. The purpose of the control rod scram time LCO is to ensure the negative scram reactivity corresponding to that used in licensing basis calculations is supported by individual control rod drive scram performance distributions allowed by the Technical Specification. The current PBAPS Technical Specifications accomplish the above purpose by placing requirements on maximum individual Control Rod Drive scram times (7.00 second requirement), average scram times and local scram times (average of three fastest control rods in all groups of four).

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_5 Labeled Comment/Discussion for ITS 3.1.3)

A new Completion Time to disarm the CRDs has been provided. The new time will allow a maximum of 2 hours for a stuck rod (proposed Required Action A.1) and 4 hours for an inoperable, non-stuck rod (proposed Required Action C.2) to complete this action. Currently, this action is required to be initiated immediately since no maximum time limit is provided. The proposed Completion times for disarming inoperable control rods are reasonable, considering that the additional requirement to fully insert the rod has been added. The 2 hour or 4 hour time limit provides time to insert (for non-stuck only) and disarm control rods without challenging plant systems.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change extends the time allowed for disarming control rods that are stuck or inoperable to a maximum of 4 hours for an inoperable rod and 2 hours for a stuck rod. Currently, existing Specification 3.3.A.2.b requires immediate action to disarm an inoperable control rod since no time limit is specified in the LCO. The probability of an accident is not increased because the proposed change will not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, tested, or inspected. The consequences of an accident are not increased because the only reason inoperable control rods are disarmed is to prevent inadvertent withdrawal during subsequent operation. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This proposed change will not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, tested, or inspected. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

NO SIGNIFICANT HAZARDS CONSIDERATIONS
SECTION 3.2--POWER DISTRIBUTION LIMITS

TECHNICAL CHANGES - MORE RESTRICTIVE

This particular No Significant Hazards Considerations is for the changes labeled "Technical Changes - More Restrictive" for the conversion to NUREG-1433. These changes incorporate more restrictive changes into the current Technical Specifications by either making current requirements more stringent or adding new requirements which currently do not exist. The following is a list of the more restrictive changes:

(M_1, M_2, and M_3 Labeled Comments/Discussions for ITS 3.2.1, 3.2.2, and 3.2.3)

M_1 A new Frequency has been added for verifying the power distribution limits (APLHGR, MCPR, and LHGR) within 12 hours of reaching or exceeding 25% RTP.

M_2 The allowed completion time for restoring the power distribution limits (APLHGR, MCPR, and LHGR) has been reduced from 5 hours to 2 hours.

M_3 Not used. B

(M_4 Labeled Comment/Discussion for ITS 3.2.2)

M_4 Currently, Specification 4.5.K.2 requires verification of the applicability of the Operating Limit MCPR values every 120 operating days by performing scram time testing. However, no specific time limit exists for determining the MCPR limits after completion of the tests. Therefore, a Completion Time of 72 hours has been provided for determining MCPR limits after completion of these scram time tests (per SR 3.1.4.2, which requires scram time testing every 120 days, consistent with the Frequency of Specification 4.5.K.2). This is an additional restriction on plant operations to ensure that MCPR limits are updated in a timely manner. In addition, the test is also required after initial scram time testing following a shutdown > 120 days (per proposed SR 3.1.4.1 scram time frequency requirement.)

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_4 Labeled Comment/Discussion for ITS 3.2.2) - continued

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change provides more stringent requirements than previously existed in the Technical Specifications. The more stringent requirements will not result in operation that will increase the probability of initiating an analyzed event. If anything the new requirements may decrease the probability or consequences of an analyzed event by incorporating the more restrictive changes discussed above. The change will not alter assumptions relative to mitigation of an accident or transient event. The more restrictive requirements will not alter the operation of process variables, structures, systems, or components as described in the safety analyses. The change has been confirmed to ensure no previously evaluated accident has been adversely affected. Therefore, the change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   Making existing requirements more restrictive and adding more restrictive requirements to the Technical Specifications will not alter the plant configuration (no new or different type of equipment will be installed) or changes in methods governing normal plant operation. The change does impose different requirements. However, the change is consistent with assumptions made in the safety analyses. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   Adding new requirements and making existing ones more restrictive either increases or does not affect the margin of safety. The change does not impact any safety analysis assumptions. As such, no question of safety is involved. Therefore, this change will not involve a significant reduction in a margin of safety.

NO SIGNIFICANT HAZARDS CONSIDERATIONS
SECTION 3.2--POWER DISTRIBUTION LIMITS

TECHNICAL CHANGES - RELOCATIONS

This proposed change relocates requirements from the Technical Specifications to a licensee controlled document. These changes are labeled "Technical Changes - Relocations." These changes are listed below:

(R_1 Labeled Comments/Discussions for ITS 3.2.1 and 3.2.2)

R_1 The requirement regarding which APLHGR limit to select from the COLR when limits are determined using hand calculations, the methods used for determining τ related to MCPR, and the associated acceptance criteria are relocated to plant procedures. Placing these requirements in plant procedures provides assurance they will be maintained. Changes to these procedures are controlled using 10 CFR 50.59.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This proposed change relocates requirements from the Technical Specifications to a licensee controlled document. The licensee controlled document containing the relocated requirements will be maintained using the provisions of 10 CFR 50.59 and is subject to the change control process in the Administrative Controls Section of the Technical Specifications. Since any changes to a licensee controlled document will be evaluated per 10 CFR 50.59, no increase (significant or insignificant) in the probability or consequences of an accident previously evaluated will be allowed. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This change relocates requirements to a licensee controlled document.

   This change will not alter the plant configuration (no new or different type of equipment will be installed) or changes in methods governing normal plant operation. This change will not impose different requirements and adequate control of information will be maintained. This

TECHNICAL CHANGES - RELOCATIONS

2. (continued)

change will not alter assumptions made in the safety analysis and licensing basis. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

This change relocates requirements from the Technical Specifications to a licensee controlled document. This change will not reduce a margin of safety since it has no impact on any safety analysis assumptions. In addition, the requirements to be transposed from the Technical Specifications to the licensee controlled document are the same as the existing Technical Specifications. Since any future changes to this licensee controlled document will be evaluated per the requirements of 10 CFR 50.59, no reduction (significant or insignificant) in a margin of safety will be allowed. Therefore, this change will not involve a significant reduction in a margin of safety.

The existing requirement for NRC review and approval of revisions, in accordance with 10 CFR 50.90, to these details and requirements proposed for relocation, does not have a specific margin of safety upon which to evaluate. However, since the proposed change is consistent with the BWR Standard Technical Specifications (NUREG-1433 approved by the NRC Staff) and the change controls for proposed relocated details and requirements provide an equivalent level of regulatory authority, revising the Technical Specifications to reflect the approved level of detail and requirements ensures no reduction in the margin of safety.

NO SIGNIFICANT HAZARDS CONSIDERATIONS
SECTION 3.2--POWER DISTRIBUTION LIMITS

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comments/Discussions for ITS 3.2.1, 3.2.2, and 3.2.3)

The requirement to initiate action within 1 hour to restore a power distribution limit is relaxed and relocated to the Bases in the form of a discussion that "prompt action" should be taken to restore the parameter to within limits. Immediate action may not always be the conservative method to assure safety. The 2 hour completion time for restoration of the limit allows appropriate actions to be evaluated by the operator and completed in a timely manner.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change does not result in any hardware changes. The requirement to initiate action within 1 hour to restore power distribution limits is not assumed to be an initiator of any analyzed event. The proposed change does not allow continuous operation with power distribution limits not maintained within limits. The total time allowed for a power distribution limit to be outside of limits is still maintained in the Technical Specifications. As a result, deleting the requirement to initiate action to restore the parameters within limits does not impact the total time the plant is allowed to operate outside the limits. As a result, the consequences of an event occurring with the proposed change are the same as the consequences of an event occurring with the current requirements. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The proposed change does not involve a physical alteration of the plant (no new or different type of equipment will be installed) or changes in methods governing normal plant operation. The proposed change will not allow continuous operation when power distribution limits are not met. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comments/Discussions for ITS 3.2.1, 3.2.2, and 3.2.3) - continued

3. Does this change involve a significant reduction in a margin of safety?

   No reduction in a margin of safety is involved with this change since the time allowed for operation with power distribution limits not met has not been affected by this change. Technical Specifications will continue to limit the amount of time operation is allowed when power distribution limits are not met. In addition, the one hour action initiation time is not an assumption of a design basis accident or transient analysis. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_2 Labeled Comments/Discussions for ITS 3.2.1, 3.2.2, and 3.2.3)

CTS 3.5.I (APLHGR), 3.5.J (LHGR), and 3.5.K (MCPR) require that if it is determined that the associated power distribution limit is not restored within the required time period, the reactor shall be in a Cold Shutdown within 36 hours. ITS 3.2.1 (APLHGR), 3.2.2 (MCPR), and 3.2.3 (LHGR) require that if the associated power distribution limit is not restored within the required Completion Time, reactor thermal power must be reduced to below 25% RTP within 4 hours. Since the ITS shutdown action does not require placing the unit in MODE 5 (Cold Shutdown), the change to the shutdown action has been categorized as a less restrictive change. The change is considered acceptable since the Applicabilities of CTS 3.5.I, 3.5.J, and 3.5.K are during reactor power operation at ≥ 25% rated thermal power. The Applicabilities of ITS 3.2.1, 3.2.2, and 3.2.3 are when THERMAL POWER is ≥ 25% RTP, which are equivalent to the CTS Applicabilities. In the event of a failure to comply with requirements of the LCO, the reactor must be placed in a non-applicable MODE or condition. The ITS change reflects placing the reactor in the first available non-applicable MODE or condition. This change also achieves consistency with CTS 3.0.A. CTS 3.0.A states "Limiting Conditions for Operation and action requirements are applicable during the operational conditions and other states specified for each specification." Since the applicability of the limiting condition for operation and actions for the CTS power distribution limits are during reactor power operation at ≥ 25% rated thermal power, reducing reactor thermal power to below 25% RTP results in exiting the power distribution limits' conditions of applicability. As a result, any further reduction in MODE or condition (to Cold Shutdown) is not required per CTS 3.0.A. In addition, not requiring the reactor to be placed in Cold Shutdown (mode switch in shutdown and average reactor coolant temperature ≤ 212°F) reduces the potential for an unnecessary shutdown transient and the resultant thermal effects on plant equipment. B

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change does not result in any hardware changes. The change to the shutdown action reflects placing the reactor in a non-applicable condition. The requirement to place the reactor in Cold Shutdown when a power distribution limit is not restored within the required completion time is not assumed to be an initiator of any analyzed event. The proposed change does not allow continuous operation in a condition where

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_2 Labeled Comments/Discussions for ITS 3.2.1, 3.2.2, and 3.2.3)

1. (continued)

power distribution limits are required to be maintained within limits. The proposed change still requires the reactor to be placed in a non-applicable condition in the event a power distribution limit can not be restored within the required Completion Time. In addition, the proposed change requires the reactor to be placed in the non-applicable condition sooner than the existing shutdown action. The Completion Time of the proposed change is based on the required time to reduce power to the required level in an orderly manner and without challenging plant systems. As a result, the consequences of an event occurring with the proposed change are the same as the consequences of an event occurring with the current shutdown action. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

The proposed change does not involve a physical alteration of the plant (no new or different type of equipment will be installed) or changes in methods governing normal plant operation. The proposed change does not allow continuous operation in a condition where power distribution limits are required to be maintained within limits. The proposed change still requires the reactor to be placed in a non-applicable condition in the event a power distribution limit can not be restored within the required Completion Time. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated. B

3. Does this change involve a significant reduction in a margin of safety?

No reduction in a margin of safety is involved with this change since the proposed change still requires the reactor to be placed in a non-applicable condition in the event a power distribution limit can not be restored within the required Completion Time. The requirement to place the reactor in Cold Shutdown when a power distribution limit is not restored within the required completion time is not an assumption of a design basis accident or transient analysis. The proposed change requires the reactor to be placed in the non-applicable condition sooner than the existing shutdown action. The Completion Time of the proposed change is based on the required time to reduce power to the required level in an orderly manner and without challenging plant systems. In addition, not

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_2 Labeled Comments/Discussions for ITS 3.2.1, 3.2.2, and 3.2.3)

3. (continued)

requiring the reactor to be placed in Cold Shutdown (mode switch in shutdown and average reactor coolant temperature $\leq$ 212°F) provides a safety benefit by reducing the potential for an unnecessary shutdown transient and the resultant thermal effects on plant equipment. Therefore, this change does not involve a significant reduction in a margin of safety.

B

ENVIRONMENTAL ASSESSMENT
SECTION 3.2--POWER DISTRIBUTION LIMITS

This proposed Technical Specification Change has been evaluated against the criteria for and identification of licensing and regulatory actions requiring environmental assessment in accordance with 10 CFR 51.21. It has been determined that the proposed changes meet the criteria for categorical exclusion as provided for under 10 CFR 51.22(c)(9). The following is a discussion of how the proposed Technical Specification Change meets the criteria for categorical exclusion.

10 CFR 51.22 (c)(9): Although the proposed change involves changes to requirements with respect to inspection or surveillance requirements;

(i) the proposed change involves no Significant Hazards Consideration (refer to the No Significant Hazards Consideration section of this Technical Specification Change Request),

(ii) there is no significant change in the types or significant increase in the amounts of any effluents that may be released offsite since the proposed changes do not affect the generation of any radioactive effluents nor do they affect any of the permitted release paths, and

(iii) there is no significant increase in individual or cumulative occupational radiation exposure.

Accordingly, the proposed change meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Based on the aforementioned and pursuant to 10 CFR 51.22(b), no environmental assessment or environmental impact statement need be prepared in connection with issuance of an amendment to the Technical Specifications incorporating the proposed changes of this request.

NO SIGNIFICANT HAZARDS CONSIDERATIONS
SECTION 3.3--INSTRUMENTATION

ADMINISTRATIVE CHANGES

The proposed change involves reformatting, renumbering, and rewording of the Technical Specifications and Bases. These changes, since they do not involve technical changes to the Technical Specifications are administrative. The following are also included in the proposed change as administrative changes.

(A_1, A_2, A_3, A_4, A_5, A_6, A_7, A_8, A_9, A_{10}, and A_{11} Labeled Comments/Discussions for ITS 3.3.1.1) B

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications. In the specific case of the RPS Section, Safety Limits Section, and Limiting Safety System Setting Section that list RPS setpoints, the Specifications have been combined into one Specification and the new Specification number is 3.3.1.1, titled Reactor Protection System (RPS) Instrumentation.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 The CHANNEL FUNCTIONAL TEST requirement has been deleted since it is encompassed by the CHANNEL CALIBRATION requirement (which is performed at the same periodicity). As such, this deletion is strictly administrative.

A_3 The note which refers to Chapter 2.0 for more information on the APRM Flow Biased High Scram equation will be deleted since the discussion of the equation in Chapter 2.0 has been relocated. This change is consistent with NUREG-1433.

ADMINISTRATIVE CHANGES
(A_1, A_2, A_3, A_4, A_5, A_6, A_7, A_8, A_9, A_{10}, and A_{11} Labeled Comments/Discussions for ITS 3.3.1.1) - continued

A_4 This proposed change will delete Note 8 from the High Drywell Pressure Function requirement when the plant is in the Startup Mode. The Note allows this Function to be inoperable when primary containment integrity is not required. Primary containment integrity, via the specifications of Section 3.6, is required in Mode 2. Therefore, the Note which allows this Function to be inoperable in Mode 2 when primary containment integrity is not required has been deleted. This change is consistent with NUREG-1433.

A_5 This change will add a Note to the Surveillance Requirements to refer to Table 3.3.1.1-1 to determine which SRs are for each RPS Function. This is an informational Note which has no technical impact on any of the Surveillance Requirements. Therefore, this change is considered administrative. This change is consistent with NUREG-1433.

A_6 This proposed change will remove the single loop term from the APRM Flow Biased High Scram Function Allowable Value. The term for single loop operation (- 0.66 Δw) will be moved to a Note b in Table 3.3.1.1-1 which discusses the reset for single loop operation. This change is consistent with NUREG-1433.

A_7 This change proposes to add a Note which will allow separate Condition entry for each channel. This change provides more explicit instructions for proper application of the Actions for Technical Specifications compliance. In conjunction with the proposed Specification 1.3 - "Completion Times," the Note ("Separate Condition entry ...") and "in one or more Functions" provides more explicit direction of the current interpretation of the existing Specifications. This change is considered administrative and is consistent with NUREG-1433.

A_8 This change proposes to delete the following requirements for the RPS Functions when in Mode 5.

- The High Reactor Pressure Function will be Operable with the mode switch in refuel and the reactor pressure vessel head bolted to the vessel.

ADMINISTRATIVE CHANGES
(A_1, A_2, A_3, A_4, A_5, A_6, A_7, A_8, A_9, A_{10}, and A_{11} Labeled Comments/Discussions for ITS 3.3.1.1)

A_8 (cont'd)

- The High Drywell Pressure Function will be Operable with the mode switch in refuel and primary containment integrity required.
- The Reactor Low Water Level Function will be Operable with the mode switch in refuel.
- The Main Steam Line Radiation Monitor High Function will be Operable with the mode switch in refuel.
- The APRM Startup High Flux and Inoperable Functions will be Operable with the mode switch in refuel.

The proposed change will delete the requirement for these Functions to be Operable when the mode switch is in the refuel mode (even if rods are withdrawn). The High Reactor Pressure Function is not required in Mode 5 because the RCS is not pressurized and the reactor pressure vessel head is not bolted on. The High Drywell Pressure Function is not required in Mode 5 because there is not enough energy in the RCS to overpressurize the drywell and containment integrity is not required. The Reactor Low Water Level Function is not required in Mode 5 because proposed Specifications 3.9.6, "RPV Water Level," 3.9.7, "RHR—High Water Level," 3.9.8, "RHR—Low Water Level," ensure adequate cooling and retention of fission product activity. The Main Steam Line Radiation Monitor High Function is not required in Mode 5 because there is not enough energy in the system to produce steam. The APRM Functions are not required in Mode 5 since they are not assumed in any safety analysis, and the IRMs are the safety related subsystem of the neutron monitoring system and are required to be Operable in Refuel with a control rod withdrawn. These changes are consistent with NUREG-1433. The change is considered administrative since Note (7) states that in this condition (effectively Mode 5) only the Mode Switch in Shutdown Function, Manual Scram Function, High Flux IRM Function and Scram Discharge Instrument Volume High Level Functions need be Operable.

A_9 This change proposes to change the Surveillance Frequency for the LPRM calibration from every 6 weeks to every 1000 MWD/T average core exposure. There are approximately 22 MWD/T average core exposure per day (cycle specific); therefore, this is approximately equal to six weeks. Therefore, this change is considered administrative in nature. This change is consistent with NUREG-1433.

ADMINISTRATIVE CHANGES
(A_1, A_2, A_3, A_4, A_5, A_6, A_7, A_8, A_9, A_{10}, and A_{11} Labeled Comments/Discussions for ITS 3.3.1.1) - continued

B

A_{10} The existing action to initiate insertion of operable rods and complete the insertion within 12 hours has been revised. For Modes 1 and 2 requirements (proposed ACTION G), the current and proposed actions already say to reduce power within 12 hours, thus a statement on one way to reduce power is not needed. The unit must be in Mode 3 within 12 hours, thus to do so, the control rod insertion must obviously be initiated at some point. It is not necessary to state this. For Mode 5 requirements (proposed ACTION H), the existing requirement would appear to provide 12 hours in which control rods could be left withdrawn, even if able to be inserted. Also, if the control rod is incapable of being inserted in 12 hours, the existing action would appear to result in an LER. The intent of the action is more appropriately presented in Required Action H.1. With the proposed action, a more conservative requirement to immediately insert the control rod(s), if capable, and to maintain them inserted is imposed. With this conservatism however, comes the understanding that if best efforts to insert the control rod(s) took longer than 12 hours, no LER would be required.

This interpretation of the intent is supported by NUREG-1433. As an enhanced presentation of the existing intent, the proposed changes are considered to be administrative.

A_{11} In Technical Specification Change Request (TSCR) 90-03 (transmitted by letter from G.A.Hunger (PECO Energy) to USNRC Document Control Desk dated September 26, 1994), the Surveillance Requirement for RPS response time testing was moved from CTS Table 4.1.2, Note 4, to CTS 4.1.A so that the RPS response time Surveillance Requirement would be located symmetrically to the corresponding CTS LCO requirement for RPS response times. TSCR 90-03 described this change as an administrative change because there were supposed to be no technical changes (either actual or interpretational) to the Technical Specifications. TSCR 90-03 was subsequently approved in Amendment Numbers 203 and 206 for PBAPS Units 2 and 3, respectively.

B

Prior to the issuance of the amendments associated with TSCR 90-03, Note 4 of CTS Table 4.1.2 stated the response time is not a part of the routine instrument channel test but will be checked once per operating cycle. Note 4 of CTS Table 4.1.2 applied to only those RPS trip functions listed in CTS Table 4.1.2. The list of RPS trip functions in CTS Table 4.1.2 includes all RPS trip functions of CTS 3.1 and 4.1, Reactor Protection System, except the following:

ADMINISTRATIVE CHANGES
(A_1, A_2, A_3, A_4, A_5, A_6, A_7, A_8, A_9, A_{10}, and A_{11} Labeled Comments/Discussions for ITS 3.3.1.1) B

A_{11} (cont'd)

Mode Switch in Shutdown,

Manual Scram,

RPS Channel Test Switch,

IRM Inoperative,

APRM Inoperative, and

APRM Downscale.

In moving the response time requirement of Note 4 of CTS Table 4.1.2 to CTS 4.1.A, an error was made. CTS 4.1.A was erroneously revised to state:

"The RPS response time test for each reactor trip function shall be demonstrated to be within limits once per operating cycle."

Since this change was described in TSCR 90-03 as an administrative change, no new response time requirements should have been imposed. However, as presently written CTS 4.1.A requires RPS response time testing to be performed on each RPS trip function which not only includes the RPS trip functions listed in CTS Table 4.1.2, but also includes the Mode Switch in Shutdown, Manual Scram, RPS Channel Test Switch, IRM Inoperative, APRM Inoperative, and APRM Downscale Functions. Prior to the issuance of the amendments associated with TSCR 90-03, RPS response time testing was not required for these additional RPS trip functions by the PBAPS Technical Specifications. To correct this error, CTS 4.1.A should state: B

"The RPS response time test for each reactor trip function in Table 4.1.2 shall be demonstrated to be within limits once per operating cycle."

Therefore, the RPS response time requirements will be added to the PBAPS ITS consistent with the correct version of CTS 4.1.A, above. Since the proposed change is correcting an error made during the processing of a Technical Specification change, there is no impact on safety. In addition, the affected RPS trip functions for which response time testing requirements were erroneously imposed are not assumed in the mitigation of design basis accidents or transient analyses.

ADMINISTRATIVE CHANGES
(A_1, A_2, A_3, A_4, A_5, A_6, A_7, A_8, A_9, A_{10}, and A_{11} Labeled Comments/Discussions for ITS 3.3.1.1)

A_{11} (cont'd) RPS response time Surveillance Requirements for each of the RPS trip functions in CTS Table 4.1.2 have been explicitly applied to the corresponding Functions in PBAPS ITS Table 3.3.1.1-1, except for the LPRM Signal Function and the Turbine First Stage Pressure Permissive Function. The response time test requirements are not explicitly listed for the LPRM Signal Function in PBAPS ITS Table 3.3.1.1-1 since the LPRMs are considered to be part of the APRM channel as described in the Bases for ITS 3.3.1.1. Therefore, the CTS response time test requirements for LPRMs are adequately addressed by the proposed response time testing requirements for the associated APRM Functions in PBAPS ITS Table 3.3.1.1-1. The response time test requirements are also not explicitly listed for the Turbine First Stage Pressure Permissive Function in PBAPS ITS Table 3.3.1.1-1 since the Turbine First Stage Pressure Permissive Function is an interlock associated with the Turbine Stop Valve - Closure Function channels and Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Function channels as described in the Bases for ITS 3.3.1.1. Therefore, the CTS response time test requirements for the Turbine First Stage Pressure Permissive are adequately addressed by the proposed response time testing requirements for the associated Turbine Stop Valve - Closure Function and Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Function in PBAPS ITS Table 3.3.1.1-1. As a result, all RPS response time requirements of CTS Table 4.1.2 are considered to be addressed, either explicitly or implicitly, by the proposed revision to PBAPS ITS 3.3.1.1 and PBAPS ITS Table 3.3.1.1-1.

(A_1 Labeled Comment/Discussion for ITS 3.3.1.2)

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

ADMINISTRATIVE CHANGES (continued)
(A_1, A_2, A_3, A_4, and A_5 Labeled Comments/Discussions for ITS 3.3.2.1)

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 Existing Specification 3.3.B.5 and Table 3.2.C (Note 1) specify that there shall be two Operable or tripped trip systems for each function of the Rod Block Monitor (RBM) System. Table 3.2.C column 1, "Minimum Number of Operable Instrument Channels per Trip System," requires 1 channel per trip system for the RBM. There are two trip systems each of which has one RBM instrument. Therefore, in accordance with existing Specifications 3.3.B.5, 3.2.C.2, and Table 3.2.C (Note 1), there must be two Operable RBM instruments and trip channels. Therefore, proposed LCO 3.3.2.1 (Table 3.3.2.1-1 Function 1, Rod Block Monitor) will require 2 Operable channels in the RBM system. This is an administrative change because the number of instrument channels and trip systems has not changed.

A_3 Existing Specifications 3.3.B.3.b.1 and 4.3.C.2 describe the control rod patterns that the Rod Worth Minimizer must enforce with the terms "prescribed control rod pattern" and "correctness of the control rod withdrawal sequence." Proposed LCO 3.3.2.1, Conditions C and D, and proposed SR 3.3.2.1.8 will identify the rod pattern that is enforced by the RWM as the banked position withdrawal sequence (BPWS) which will establish the required rod patterns as described in NEDO 21231, "Banked Position Withdrawal Sequence."

A_4 Existing Table 3.2.C (Note 11) states that the values for the Rod Block Monitor high trip setpoint, intermediate trip setpoint, low trip setpoint, and downscale trip setpoint are located in the Core Operating Limits Report (COLR). Proposed LCO 3.3.2.1 (Table 3.3.2.1-1) will also reference the COLR as the location of these limits.

ADMINISTRATIVE CHANGES
(A_1, A_2, A_3, A_4, and A_5 Labeled Comments/Discussions for ITS 3.3.2.1) - continued

A_5 Notes preceding proposed SR 3.3.2.1.4 and 3.3.2.1.5 will permit the neutron detectors to be excluded from the RBM Functional Test and RBM Channel Calibration. The neutron detectors are excluded from these 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 3.3.1.1.8. Existing Table 4.2.C (Note 3) allows the use of a "simulated electrical signal" when performing a functional test or calibration of the Rod Block Monitors. This is equivalent to the proposed Note that excludes neutron detectors from testing. This change is consistent with BWR Standard Technical Specifications, NUREG-1433.

(A_1, A_2, A_3 and A_4, Labeled Comments/Discussions for ITS 3.3.3.1)

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. During this reformatting and renumbering process, no technical changes (either actual or interpretational) to the TS were made unless they were identified and justified.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 An Applicability for Post Accident Monitoring (PAM) instrumentation has been specified consistent with the required function of the instrumentation. PAM instrumentation is required to monitor variables related to the diagnosis and preplanned actions required to mitigate design basis accidents which are assumed to occur in MODES 1 and 2. As such, the Applicability has been specified as MODES 1 and 2. The change is considered administrative in nature since in general the existing shutdown requirements associated with

ADMINISTRATIVE CHANGES
(A_1, A_2, A_3 and A_4, Labeled Comments/Discussions for ITS 3.3.3.1)

A_2 (cont'd) PAM instrumentation being retained in Technical Specifications reflect placing the unit in MODE 3 (the non-applicable Mode). The shutdown actions for those instruments that are not consistent with this Applicability will be addressed separately.

A_3 Two Notes have been provided which modify the Actions of the PAM Specification. Note 1 states that the provisions of LCO 3.0.4 are not applicable. As a result, a Mode change is allowed when PAM instrumentation is inoperable. This allowance is provided due to the passive function of the instruments, the operator's ability to diagnose an accident using alternative instruments and methods and the low probability of an event requiring the use of these instruments. Adding Note 1 is considered an administrative change because existing PBAPS Technical Specifications do not have a requirement that prohibits entry into a Mode or condition when an LCO required by that Mode or condition is not satisfied. Therefore, existing Technical Specifications already allow the actions permitted by Note 1. Note 2 provides more explicit instructions for proper application of the Actions for Technical Specifications compliance. In conjunction with the proposed Specification 1.3 - "Completion Times," the Note ("Separate Condition entry is allowed for each Function") provides direction consistent with the intent of the existing Action for an inoperable PAM instrumentation channel. Since Note 2 only provides more explicit direction of the current interpretation of the existing specifications, this change is considered administrative.

A_4 A new Condition D was added to direct the user to the appropriate Condition when the Required Action and associated Completion Time of Condition C is not met. This addition is an administrative change consistent with NUREG-1433.

(A_1 Labeled Comment/Discussion for ITS 3.3.3.2)

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

ADMINISTRATIVE CHANGES

(A_1 Labeled Comment/Discussion for ITS 3.3.3.2)

A_1 (cont'd) Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

(A_1 and A_2 Labeled Comments/Discussions for ITS 3.3.4.1)

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 A proposed Note at the start of the Actions Table ("Separate Condition entry is allowed for each channel.") provides more explicit instructions for proper application for the new Actions for Technical Specification compliance. In conjunction with the proposed Specification 1.3 "Completion Times," this Note provides direction consistent with the intent of the Required Actions for inoperable ATWS-RPT channels, functions, trip systems or recirculation pump breakers. It is intended that each Required Action be applied regardless of it having been applied previously for other inoperable ATWS-RPT channels, functions, trip systems or recirculation pump breakers.

ADMINISTRATIVE CHANGES (continued)
(A_1, A_2, A_3, A_4, A_5, A_6, A_7, and A_8 Labeled Comments/Discussions for ITS 3.3.5.1)

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications. In the specific case of the ECCS Instrumentation Section, and Limiting Safety System Setting Section that list ECCS Instrumentation setpoints, the Specifications have been combined into one Specification and the new Specification number is 3.3.5.1, titled Emergency Core Cooling System (ECCS) Instrumentation.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 Not used.

A_3 This change deletes the specific line items for performing the Logic System Functional Test for the Containment Cooling Subsystems from current Technical Specification Table 4.2.B. The proposed Technical Specifications groups specific Functions by ECCS System (e.g., the Containment Cooling Subsystems will be depicted as the specific functions which provide the isolation of the applicable valves in these subsystems, Function 2.e in Table 3.3.5.1-1). Since the test is retained for these items, this change constitutes an administrative change. In addition, the first sentence of Note 4 has been deleted since it is duplicative of the simulated automatic actuation test requirement in each of the current ECCS Specifications. These changes are consistent with NUREG-1433.

ADMINISTRATIVE CHANGES
(A_1, A_2, A_3, A_4, A_5, A_6, A_7, and A_8 Labeled Comments/Discussions for ITS 3.3.5.1) - continued

A_4 This proposed change deletes the note in the current Technical Specifications which allows specific instrumentation to be excluded from the functional test definition as it is adequately addressed by the proposed Channel Functional Test definitions. All changes to definitions in the current Technical Specification were justified in the Discussion of Changes to Chapter 1.0, "Use and Applications." Thus, any deviations from any test required by Table 3.3.5.1-1 will be specified in the individual surveillance procedures. This change is consistent with NUREG-1433.

A_5 The current Applicability for the ECCS Instrumentation is when the system(s) it initiates or controls are required to be Operable as specified in Section 3.5. The changes to the specific ECCS System Applicabilities were described in the Discussion of Changes for Section 3.5. This proposed change specifies by a footnote (footnote d)that the only time the HPCI Functions are required to be Operable in Modes 2 and 3 is with reactor steam dome pressure > 150 psig. This proposed change also specifies by a footnote (footnote e) that the only time the ADS Functions are required to be Operable in Modes 2 and 3 is with reactor steam dome pressure > 100 psig. Since the Applicability of the HPCI and ADS Instrumentation is consistent with the requirements of the HPCI System and ADS Specifications in Section 3.5, this is considered an administrative change. This change is consistent with NUREG-1433.

A_6 The Calibration specified in the Logic System Functional Test Table for the specific time delay relays will be deleted from the note. The proposed Technical Specifications will specify in Table 3.3.5.1-1 that Channel Calibrations are required for the specific time delay relays. This change is consistent with NUREG-1433.

A_7 This change proposes to add a Note which will allow separate Condition entry for each channel. This change provides more explicit instructions for proper application of the Actions for Technical Specifications compliance. In conjunction with the proposed Specification 1.3 - "Completion Times," the Note ("Separate Condition entry ...") and "in one or more Functions" provides more explicit direction of the current interpretation of the existing Specifications. This change is considered administrative and is consistent with NUREG-1433.

ADMINISTRATIVE CHANGES
(A_1, A_2, A_3, A_4, A_5, A_6, A_7, and A_8 Labeled Comments/Discussions for ITS 3.3.5.1) - continued

A_8 This proposed change deletes the line item for the quarterly Channel Functional Test. The Channel Calibration encompasses the Channel Functional Test. Since the Channel Calibration is also required quarterly a separate line item for the Channel Functional Test is not required. This change is consistent with NUREG-1433.

(A_1, A_2, A_3, A_4, and A_5 Labeled Comments/Discussions for ITS 3.3.5.2)

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

In the specific case of the RCIC Instrumentation and Limiting Safety System Settings Sections that list RCIC System Instrumentation setpoints, Specifications have been combined into one Specification and the new Specification number is 3.3.5.2, RCIC System Instrumentation.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 This change proposes to add a Note which will allow separate Condition entry for each channel. This change provides more explicit instructions for proper application of the Actions for Technical Specifications compliance. In conjunction with the proposed Specification 1.3 - "Completion Times," the Note ("Separate Condition entry ...") and "in one or more Functions" provides more explicit direction of the current interpretation of the existing Specifications. This change is considered administrative and is consistent with NUREG-1433.

ADMINISTRATIVE CHANGES
(A_1, A_2, A_3, A_4, and A_5 Labeled Comments/Discussions for ITS 3.3.5.2) - continued

A_3 The current Applicability for the RCIC Instrumentation is when the system(s) it initiates or controls are required to be Operable as specified in CTS Section 3.5. This proposed change adds the specific Applicability in ITS Section 3.5.3. The specific differences between the Applicabilities in the CTS and ITS are described in the Discussion of Changes for Section 3.5. Based on this fact, the proposed change is administrative. This change is consistent with NUREG-1433.

A_4 This proposed change deletes the note in the current Technical Specifications which allows specific instrumentation to be excluded from the functional test definition. All changes to definitions in the current Technical Specification were justified in the Discussion of Changes to Chapter 1.0, "Use and Applications." Thus, any deviations from any test required by Table 3.3.5.2-1 will be specified in the individual surveillance procedures. In addition, the first sentence of Note 4 has been deleted since it is duplicative of the simulated automatic actuation test requirement in the current RCIC System Specification. These changes are consistent with NUREG-1433.

A_5 This change proposes to delete the note requiring the logic system functional tests to include a calibration of time delay relays and timers necessary for proper functioning of the trip system. This note is not applicable to RCIC since RCIC does not have any timers or time delay relays. This change is consistent with NUREG-1433.

(A_1, A_2, A_3, A_4, A_5, A_6, and A_7 Labeled Comments/Discussions for ITS 3.3.6.1)

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications. In the specific case of the Primary Containment Isolation (PCI) Instrumentation Section, ECCS Instrumentation Section, and the Limiting Safety System Setting Section that list PCI instrumentation setpoints, the Specifications have been combined into one Specification and the new Specification is 3.3.6.1, titled Primary Containment Isolation Instrumentation.

ADMINISTRATIVE CHANGES
(A_1, A_2, A_3, A_4, A_5, A_6, and A_7 Labeled Comments/Discussions for ITS 3.3.6.1)

A_1 (cont'd) Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 The steam line temperature monitoring system for Main Steam, HPCI, and RCIC each consist of 16 temperature detectors monitoring 4 locations with one detector from each of the areas monitored contributing to one of four trip strings. Any of the 4 channels in a trip string is capable of tripping the trip string. The trip strings are arranged in a one-out-of-two-twice logic. Therefore, proposed Table 3.3.6.1-1 Functions 1.e (Main Steam), 3.e (HPCI), and 4.e (RCIC) are presented as having 2 trip systems with 8 channels required per trip system. This change creates consistency between Main Steam, HPCI and RCIC and is consistent with BWR Standard Technical Specifications, NUREG-1433.

A_3 This change proposes to add a Note which will allow separate Condition entry for each channel. This change provides more explicit instructions for proper application of the Actions for Technical Specifications compliance. In conjunction with proposed Specification 1.3 - "Completion Times," the Note ("Separate Condition entry is allowed for each channel.") provides more explicit direction of the interpretation of the existing Specifications. This change is considered administrative and is consistent with BWR Standard Technical Specifications, NUREG-1433.

A_4 Existing Table 3.2.B, under "Minimum Number of Operable Channels per Trip System," requires that the HPCI Steam Line Low Pressure Function have 4 Operable channels per trip system. Table 3.2.B Note (5) states that HPCI has only one trip system for this function. UFSAR 7.3.4.8 and associated drawings indicated that low pressure in the HPCI turbine steam line is sensed by four pressure switches which are arranged as two trip systems, both of which must trip to initiate isolation of the HPCI turbine steam line. Each trip system receives inputs from two pressure switches, either one of which can

ADMINISTRATIVE CHANGES
(A_1, A_2, A_3, A_4, A_5, A_6, and A_7 Labeled Comments/Discussions for ITS 3.3.6.1)

A_4 (cont'd) initiate isolation. Proposed Specification 3.3.6.1, Table 3.3.6.1-1, Function 3.c, reflects the design as described in the UFSAR and associated plant drawings. Since the total number of channels required remains at 4, the change is considered administrative in nature.

A_5 Existing Table 3.2.D, Notes 1 and 3, identify the Applicability for Function 2.c, Main Stack Monitor Radiation—High, in proposed Table 3.3.6.1-1. Currently, this Function must be Operable "only when the containment is purging through the SGTS and containment integrity is required." Proposed Specification 3.3.6.1 will require that this Function be Operable in Modes 1, 2, and 3. This is an administrative change because Primary containment is required in Modes 1, 2, and 3. Additionally, isolation of the affected penetrations satisfies the Required Action for this Function which would permit the Main Stack Monitor Radiation—High Function to be inoperable in Modes 1, 2, and 3 except when the containment is being purged.

A_6 This proposed change deletes the line item for the quarterly Channel Functional Test. The Channel Calibration encompasses the Channel Functional Test. Since the Channel Calibration is also required quarterly, a separate line item for the Channel Functional Test is not required.

A_7 This proposed change deletes Note 3 in the current Technical Specifications which allows specific instrumentation to be excepted from the functional test definition as it is adequately addressed by the proposed Channel Functional Test definition. All changes to definitions in the current Technical Specifications were justified in the Discussion of Changes to Chapter 1.0, "Use and Applications." Thus, any deviations from any test required by Table 3.3.6.1-1 will be specified in the individual surveillance procedures. The first sentence of current Note 4 has been deleted since it is duplicative of the simulated automatic actuation test requirement in the current primary containment isolation valves specification. The calibration specified in current Note 6 for the time delay relays and timers has been deleted. The proposed Technical Specifications will specify in Table 3.3.6.1-1 that Channel Calibrations are required for the specified time delay relays. These changes are consistent with NUREG-1433.

ADMINISTRATIVE CHANGES (continued)
(A_1, A_2, A_3, A_4, A_5, A_6, A_7, and A_8 Labeled Comments/Discussions for ITS 3.3.6.2)

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

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A_2 This change will replace the current "Minimum No. of Operable Instrument Channels" and "No. of Instrument Channels Provided by Design," columns with a "Required Channels Per Trip System" column. This specifies the number of channels required to be Operable to get the actuation when required. This number includes provisions for the single failure criterion. This change is consistent with NUREG-1433.

A_3 This change will delete the requirement that Channel Functional Tests, Channel Calibrations, and Channel Checks are not required when the instruments are not required to be operable or are tripped. If a channel is outside of its Mode of Applicability or inoperable then there is no reason the test needs to be performed. The tests will, however, be performed on the channel prior to entering the Mode of Applicability or declaring the channel Operable. This is consistent with ITS Section 3.0. If a channel is tripped, testing does not need to be performed because the channel has performed its function. This change is consistent with NUREG-1433.

A_4 This change deletes the logic system functional test note which specifies that a calibration of time delay relays and timers necessary for proper functioning of the trip systems will be performed with the logic system functional test. This note is not applicable to PBAPS since there are no timers or delay relays associated with the Secondary Containment Isolation Instrumentation. This change is consistent with NUREG-1433.

ADMINISTRATIVE CHANGES
(A_1, A_2, A_3, A_4, A_5, A_6, A_7, and A_8 Labeled Comments/Discussions for ITS 3.3.6.2) - continued

A_5 This change proposes to add a Note which will allow separate Condition entry for each channel. This change provides more explicit instructions for proper application of the Actions for Technical Specifications compliance. In conjunction with the proposed Specification 1.3 - "Completion Times," the Note ("Separate Condition entry ...") and "in one or more Functions" provides more explicit direction of the current interpretation of the existing Specifications. This change is considered administrative and is consistent with NUREG-1433.

A_6 The current Applicability for the Secondary Containment Isolation Radiation Monitoring Instrumentation is whenever the system(s) are required to be Operable (i.e., when Secondary Containment is required to be Operable). This proposed Applicability specifies the instrumentation to be Operable in Modes 1, 2, and 3, and during Core Alterations, operation with a potential for draining the reactor vessel, and during movement of irradiated fuel assemblies in secondary containment as applicable to each Function. The proposed Specification Applicability is the same as for the Secondary Containment Specifications in ITS Section 3.6. The justification for the differences between the current and proposed Applicability for Secondary Containment requirements is provided in the Discussion of Changes for ITS Section 3.6 "Containment Systems." Therefore, this change is administrative. This change is consistent with NUREG-1433.

A_7 Not used.

A_8 This proposed change deletes the line item for the quarterly Channel Functional Test. The Channel Calibration encompasses the Channel Functional Test. Since the Channel Calibration is also required quarterly, a separate line item for the Channel Functional Test is not required.

(A_1 and A_2 Labeled Comments/Discussions for ITS 3.3.7.1)

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

ADMINISTRATIVE CHANGES
(A_1 and A_2 Labeled Comments/Discussions for ITS 3.3.7.1)

A_1 (cont'd) Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 A proposed Note at the start of the Actions Table ("Separate Condition entry is allowed for each channel.") provides more explicit instructions for proper application for the new Actions for Technical Specification compliance. In conjunction with the proposed Specification 1.3 - "Completion Times," this Note provides direction consistent with the intent of the Required Actions for inoperable MCREV System instrumentation channels or trip systems. It is intended that each Required Action be applied regardless of it having been applied previously for other inoperable MCREV System instrumentation channels or trip systems.

(A_1, A_2, A_3, A_4, and A_5 Labeled Comments/Discussions for ITS 3.3.8.1)

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

ADMINISTRATIVE CHANGES
(A_1, A_2, A_3, A_4, and A_5 Labeled Comments/Discussions for ITS 3.3.8.1) - continued

A_2 This change will replace the current "Minimum No. of Operable Instrument Channels Per Trip System" and "Number of Instrument Channels Provided by Design," columns with a "Required Channels Per Bus" column. This specifies the number of channels required to be Operable to ensure a DG start when required. This change is consistent with NUREG-1433.

A_3 This change proposes to add a Note which will allow separate Condition entry for each channel. This change provides more explicit instructions for proper application of the Actions for Technical Specifications compliance. In conjunction with the proposed Specification 1.3 - "Completion Times," the Note ("Separate Condition entry ...") and "in one or more Functions" provides more explicit direction of the current interpretation of the existing Specifications. This change is considered administrative and is consistent with NUREG-1433.

A_4 The current Applicability for the LOP Instrumentation is when the system(s) it initiates or controls are required to be Operable. This proposed change adds the specific Applicability for LOP Instrumentation by referring to the applicable AC Sources Specifications (LCO 3.8.1 and LCO 3.8.2). Based on this the proposed change is considered to be administrative.

A_5 This change replaces the Trip Level Setting Value with the Allowable Value for the Loss of Power Instrumentation Functions. The current Technical Specification (CTS) Trip Level Setting Values are the same as the proposed Allowable Values and have been treated as the Allowable Values. These values were derived from the limiting values of the process parameters obtained from the safety analysis and corrected for calibration, process, and some of the instrument errors. Since the CTS values are the same as the proposed values this change is considered administrative.

(A_1 and A_2 Labeled Comments/Discussions for ITS 3.3.8.2)

A_1 All reformatting and renumbering is in accordance with the BWR/4 Standard Technical Specifications (STS), NUREG-1433. As a result, the Technical Specifications (TS) should be more readily readable, and therefore understandable, by plant operators as well as other users. The reformatting, renumbering, and rewording process involves no technical changes to existing Technical Specifications.

ADMINISTRATIVE CHANGES (continued)
(A_1 and A_2 Labeled Comments/Discussions for ITS 3.3.8.2)

A_1 (cont'd) Editorial rewording (either adding or deleting) is made consistent with NUREG-1433. During ITS development certain wording preferences or English language conventions were adopted which resulted in no technical changes (either actual or interpretational) to the Technical Specifications. Additional information has also been added to more fully describe each subsection. This wording is consistent with the BWR Standard Technical Specifications, NUREG-1433. Since the design is already approved by the NRC, adding more detail does not result in a technical change.

A_2 The Applicability of the RPS electric power monitoring assemblies has been specified consistent with the Applicability of the RPS Functions. As such, the change is considered administrative in nature.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change involves reformatting, renumbering, and rewording of the existing Technical Specifications and Bases along with other changes to the Technical Specifications discussed above. The reformatting, renumbering, and rewording along with the other changes listed involves no technical changes to existing Technical Specifications. The change to the existing Technical Specifications was done in order to be consistent with the NUREG-1433. During development of NUREG-1433, certain wording preferences or English language conventions were adopted. The proposed change to this Section is administrative in nature and does not impact initiators of analyzed events. It also does not impact the assumed mitigation of accidents or transient events. Therefore, the change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

ADMINISTRATIVE CHANGES (continued)

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The proposed change does not involve a physical alteration of the plant (no new or different type of equipment will be installed) or changes in methods governing normal plant operation. The proposed change will not impose any new or different requirements or eliminate any existing requirements. Therefore, the change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   The change is administrative in nature and will not involve any technical changes. The proposed change will not reduce a margin of safety because it has no impact on any safety analysis assumptions. Also, because the change is administrative in nature, no question of safety is involved. Therefore, the change does not involve a significant reduction in a margin of safety.

NO SIGNIFICANT HAZARDS CONSIDERATIONS
SECTION 3.3--INSTRUMENTATION

TECHNICAL CHANGES - MORE RESTRICTIVE

This particular No Significant Hazards Considerations is for the changes labeled "Technical Changes - More Restrictive" for the conversion to NUREG-1433. These changes incorporate more restrictive changes into the current Technical Specifications by either making current requirements more stringent or adding new requirements which currently do not exist. The following is a list of the more restrictive changes.

(M_1, M_2, M_3, and M_4 Labeled Comments/Discussions for ITS 3.3.1.1)

M_1 The proposed change will add restrictions to the provision which allows the Scram Discharge Volume High Function to be bypassed when the mode switch is in refuel or shutdown. The proposed change requires this Function to be Operable whenever any control rod is withdrawn from a core cell containing one or more fuel assemblies. This will ensure that if an RPS initiated scram occurs the control rod insertion will not be hindered by the scram discharge volume being too high. This change is consistent with NUREG-1433.

M_2 The proposed change will require the plant to be in MODE 3 if Actions A, B, or C cannot be completed within the required Completion Time (which is outside the Modes of Applicability). The current requirement allows the plant to be taken to MODE 2 with or without the control rods inserted. Since the APRM Inoperative is required to be Operable whenever the other APRM Functions are Operable and the APRM Startup High Flux Scram Function is required in MODE 2, bringing the plant to MODE 2 will not place the Function outside its Mode of Applicability. Therefore, it is more appropriate to bring the plant to MODE 3 which is outside the Modes of Applicability. This change is consistent with NUREG-1433.

M_3 This proposed change adds the following Surveillance Requirements for the RPS Functions in the Technical Specification.

- Requirements to perform Channel Checks every 12 hours (SR 3.3.1.1.1) were added for the functions listed below:

  IRM High Flux (Mode 2 and Mode 5)
  APRM Startup High Flux Scram (Mode 2)
  APRM Flow Biased High Scram
  APRM Scram Clamp
  Main Steam Line High Radiation

- A requirement was added to verify SRM and IRM channels overlap prior to withdrawing SRMs from the fully inserted position (SR 3.3.1.1.5).

NO SIGNIFICANT HAZARDS CONSIDERATIONS
SECTION 3.3--INSTRUMENTATION

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, M_3, and M_4 Labeled Comments/Discussions for ITS 3.3.1.1)

M_3 (cont'd)

- A requirement was added to perform a Channel Functional Test every 92 days for the APRM Flow Biased High Scram Function.

- A requirement was added to perform a Channel Calibration of the function listed below every 184 days (SR 3.3.1.1.11):

  IRM High Flux (Mode 2 and Mode 5)

- A requirement was added to perform a Channel Calibration of the functions listed every 18 months (SR 3.3.1.1.12):

  APRM Startup High Flux Scram (Mode 2)
  APRM Scram Clamp

- Requirements were added to perform Logic System Functional Tests every 24 months (SR 3.3.1.1.17) for the following functions:

  IRM High Flux (Mode 2 and Mode 5)
  IRM Inop (Mode 2 and Mode 5)
  APRM Startup High Flux Scram (Mode 2)
  APRM Flow Biased High Scram
  APRM Scram Clamp
  APRM Downscale
  APRM Inop (Mode 1 and Mode 2)
  Reactor Vessel Pressure High
  Reactor Vessel Water Level Low
  Main Steam Isolation Valve Closure
  Drywell Pressure High
  SDV Water Level High (Mode 1, Mode 2, and Mode 5)
  Turbine Stop Valve Closure
  Turbine Control Valve Fast Closure, Trip Oil Pressure Low
  Reactor Mode Switch - Shutdown Position (Mode 1, Mode 2, and Mode 5)
  Turbine Condenser Low Vacuum
  Main Steam Line High Radiation
  Manual Scram (Mode 1, Mode 2, and Mode 5)
  RPS Channel Test Switch (Mode 1, Mode 2, and Mode 5)

The addition of new requirements (Surveillances) to the current Technical Specifications constitutes a more restrictive change. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, M_3, and M_4 Labeled Comments/Discussions for ITS 3.3.1.1) - continued

M_4 The proposed change will increase the Frequency of the Channel Checks for current Technical Specification RPS Functions of High Pressure, High Drywell Pressure, Reactor Low Water Level, and Turbine Condenser Low Vacuum from once per day to once per 12 hours. The Channel Check ensures that a gross failure of instrumentation has not occurred. By detecting these gross failures, the Channel Check is the key to verifying the instrument continues to operate properly between each Channel Calibration. This change adds additional requirements and it constitutes a more restrictive change. This change is consistent with NUREG-1433.

(M_1, M_2, M_3, M_4, M_5, M_6, M_7, M_8, M_9, and M_{10} Labeled Comments/Discussions for ITS 3.3.1.2)

M_1 Existing Specifications 3.3.B.4 and 4.3.B.4 require Source Range Monitors (SRMs) to be Operable whenever control rods are withdrawn for startup or refueling. Proposed LCO 3.3.1.2 (Table 3.3.1.2-1) will require SRMs to be Operable at all times in Mode 2 prior to and during control rod withdrawal until the flux level is sufficient to maintain the Intermediate Range Monitor (IRM) on Range 3 or above. This more restrictive change is consistent with BWR Standard Technical Specifications, NUREG-1433.

M_2 Existing Specifications 3.3.B.4 and 4.3.B.4 require SRMs to have an observable count rate with a signal to noise ratio above the curve in Figure 3.3.1 (proposed Figure 3.3.1.2-1); however, the number of SRMs required during rod withdrawal may be reduced from 3 channels to 2 channels if the observed count rate is above 3 counts per second (cps). Proposed LCO 3.3.1.2 will also require an observable count rate with a signal to noise ratio above the curve in Figure 3.3.1.2-1 but will not allow a reduction in the number of Operable SRM channels if the count rate is above 3 cps. This more restrictive change is consistent with BWR Standard Technical Specifications, NUREG-1433. However, the number of required SRM channels during Mode 2 and during Core Alterations may be reduced to 2 or fewer during certain circumstances as discussed in the less restrictive changes for this section.

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, M_3, M_4, M_5, M_6, M_7, M_8, M_9, and M_{10} Labeled Comments/Discussions for ITS 3.3.1.2) - continued

M_3 Existing Specification 4.3.B.4 requires verification "prior to control rod withdrawal during startup" and Specification 3.10.B.1.b requires verification during "Alterations of the Core" that SRMs have an observable count rate with a signal to noise ratio above the curve shown in Figure 3.3.1 (proposed Figure 3.3.1.2-1). Proposed SR 3.3.1.2.4 has the same requirements; however, SR 3.3.1.2.4 will require periodic verification of the SRM count rate at least once per 24 hours while in Mode 5, Mode 4, and Mode 3 and in Mode 2 when IRMs are on Range 2 or below. Periodic verification of SRM count rate will be required every 12 hours during Core Alterations. This change is consistent with BWR Standard Technical Specifications, NUREG-1433.

M_4 Proposed LCO 3.3.1.2 will require 3 additional Surveillance Tests to demonstrate SRM Operability when the IRMs are on Range 2 or below in Mode 2. The proposed Surveillances are: SR 3.3.1.2.1 which will require performance of an SRM Channel Check every 12 hours; SR 3.3.1.2.6 which will require an SRM Channel Functional Test and determination of signal to noise ratios every 31 days; and, SR 3.3.1.2.7 which will require an SRM Channel Calibration every 184 days. Proposed SR 3.3.1.2.6 and SR 3.3.1.2.7 will be modified by a Note that will allow deferral of these Surveillances until 12 hours after the IRMs are on Range 2 or below when the reactor is being shutdown. SR 3.3.1.2.7 is also modified by a Note that excludes the neutron detectors from calibration requirements because the detectors are fission chambers that are designed to have a relatively constant sensitivity over the range and with an accuracy specified for a fixed useful life and cannot readily be adjusted. These additional requirements for testing of SRMs are consistent with BWR Standard Technical Specifications, NUREG-1433.

M_5 Existing Specifications do not have any requirements for SRM Operability during Mode 3 and Mode 4. Proposed LCO 3.3.1.2 (Table 3.3.1.2-1) will require 2 SRM channels to be Operable at all times in Mode 3 and Mode 4. Additionally, SRM Operability in Modes 3 and 4 must be demonstrated by the performance of proposed SR 3.3.1.2.3, SR 3.3.1.2.4, SR 3.3.1.2.6, and SR 3.3.1.2.7. Proposed LCO 3.3.1.2, Condition D, will require that all insertable control rods be fully inserted and the reactor mode switch be in the shutdown position within 1 hour if less than the 2 required SRM channels are Operable. The requirements for SRM Operability in Mode 3 and Mode 4 and the associated Surveillance Tests, Conditions, Required Actions and Completion Times are consistent with BWR Standard Technical Specifications, NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, M_3, M_4, M_5, M_6, M_7, M_8, M_9, and M_{10} Labeled Comments/Discussions for ITS 3.3.1.2) - continued

M_6 Existing Specifications 3.10.B.1 and 3.10.B.5 establish requirements for the location of SRMs during Core Alterations and during core unloading and reloading. Proposed SR 3.3.1.2.2 will set similar requirements for SRM location during Core Alterations which because of a change in the Definition of Core Alteration will include core loading and unloading. Proposed SR 3.3.1.2.2 will add a new requirement to verify every 12 hours during Core Alterations that the SRMs are properly located. Additionally, SR 3.3.1.2.2 will require that one of the SRMs be located in "the fueled region" during all Core Alterations whereas the existing 3.10.B.5 required that one of the SRMs be located in "intermediate arrays of fuel" during the unloading and reloading of fuel. Finally, in both the existing and proposed specifications, only 2 SRMs are required to be Operable but three SRM location criteria are identified. Note 2 to proposed SR 3.3.1.2.2 will explicitly acknowledge that one SRM may be used to satisfy more than one location criteria. The proposed changes are consistent with BWR Standard Technical Specifications, NUREG-1433.

M_7 Proposed LCO 3.3.1.2 (Table 3.3.1.2-1) will require that Channel Functional Tests (proposed SR 3.3.1.2.5) be performed every 7 days when in Mode 5 instead of prior to core alterations and prior to core unloading and reloading as is currently required by Specifications 4.10.B.1 and 4.10.B.2. SR 3.3.1.2.5 will also add the requirement to determine signal to noise ratios once per 7 days. Additionally, proposed LCO 3.3.1.2 (Table 3.3.1.2-1) will require that Channel Checks (proposed SR 3.3.1.2.1) be performed every 12 hours when in Mode 5 instead of prior to unloading and reloading of fuel and prior to and daily during alterations of the core as is currently required by Specifications 4.10.B.1 and 4.10.B.2. Proposed SR 3.3.1.2.1 and SR 3.3.1.2.5 are more restrictive than the existing specifications. The proposed changes are consistent with BWR Standard Technical Specifications, NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, M_3, M_4, M_5, M_6, M_7, M_8, M_9, and M_{10} Labeled Comments/Discussions for ITS 3.3.1.2) - continued

M_8 Proposed LCO 3.3.1.2 (Table 3.3.1.2-1 MODES requirements) will add a new requirement to perform a Channel Calibration (proposed SR 3.3.1.2.7) every 184 days to verify the performance of the SRM detectors and associated circuitry. SR 3.3.1.2.7 will be modified by a Note that excludes the neutron detectors from calibration requirements because the detectors are fission chambers that are designed to have a relatively constant sensitivity over the range and with an accuracy specified for a fixed useful life and cannot readily be adjusted. Note 2 to proposed SR 3.3.1.2.7 will explicitly acknowledge that the Channel Calibration cannot be performed at power and will allow deferring performance until 12 hours after the IRMs are on Range 2 or below during a reactor shutdown. The proposed changes are consistent with BWR Standard Technical Specifications, NUREG-1433.

M_9 Existing specifications require that SRMs be Operable "during Alterations of the Core" and "prior to control rod withdrawal for startup or during refueling. Proposed LCO 3.3.1.2 (Table 3.3.1.2-1) will establish Operability requirements for SRMs at all times during Mode 3, Mode 4, and Mode 5 and during Mode 2 when the IRMs are on Range 2 or below. The proposed changes are consistent with BWR Standard Technical Specifications, NUREG-1433.

M_{10} Existing Specification 3.10.B does not identify Required Actions if SRM Operability requirements in Mode 5 are not satisfied; therefore, Specification 3.10.B defaults to LCO 3.0.C. Proposed LCO 3.3.1.2 will add Required Actions if less than the required number of SRMs are Operable in Mode 5. If one or more required SRMs are inoperable when in Mode 5, proposed LCO 3.3.1.2 Condition E will require that Core Alterations be terminated and action be taken immediately to fully insert all control rods. The proposed changes are consistent with BWR Standard Technical Specifications, NUREG-1433.

(M_1, M_2, M_3, M_4, and M_5 Labeled Comments/Discussions for ITS 3.3.2.1)

M_1 The proposed Specification 3.3.2.1, Control Rod Block Instrumentation, will include specific requirements in Table 3.3.2.1-1 for the RBM "Inop" function (proposed Function 1.d.) and RBM Timer Bypass (proposed Function 1.d.). These RBM functions, were included in the ARTS/MELLLA analysis for the RBM. ARTS/MELLLA analysis is documented NEDC-32162P, Rev.1, "Maximum Extended Load Line Limit and

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, M_3, M_4, and M_5 Labeled Comments/Discussions for ITS 3.3.2.1)

M_1 (cont'd) ART Improvement Program Analyses for Peach Bottoms Atomic Power Station Unit 2 and 3." The RBM Bypass Timer must be set to "minimum" because the current analysis does not support the use of the timer which is used to compensate for a noisy instrument channel that could prevent rod withdrawal. All Conditions, Required Actions, and Surveillance Tests for the RBM are also Applicable to the "Inop" and "Timer Bypass" functions of the RBM. This change is consistent with BWR Standard Technical Specifications, NUREG-1433.

M_2 Proposed Specification 3.3.2.1, Control Rod Block Instrumentation, will include the Control Rod Block Function of the Reactor Mode Switch as a required function (Function 3 on proposed Table 3.3.2.1-1). The new requirement is that 2 channels of the Rod Block function of Reactor Mode Switch -- Shutdown Position must be Operable whenever the Mode Switch is in the Shutdown position. This addition to the specification for the Control Rod Block Instrumentation will include proposed SR 3.3.2.1.7 (Channel Functional Test every 24 months) and proposed LCO 3.3.2.1, Condition E (Required Actions and Completion Times if this function is inoperable). Proposed SR 3.3.2.1.7 will not be required to be performed until 1 hour after the Reactor Mode Switch is placed in Shutdown. This change is consistent with BWR Standard Technical Specifications, NUREG-1433.

M_3 Existing specifications require that the Rod Block Monitor must be Operable: "During operations with limiting control rod patterns, as determined by qualified personnel" (3.3.B.5); "For Startup and Run Positions of the Reactor Mode Switch" except that "RBM rod blocks need not be Operable in 'Startup' mode" (Table 3.2.C, Note 1); and, RBM "trip is bypassed when reactor power is ≤ 30%" (Table 3.2.C Note 7). Proposed Specification 3.3.2.1, Control Rod Block Instrumentation, will identify the Applicability for the RBM in Footnotes (a), (b), (c), (d), and (e) which can be summarized as the RBM must be Operable when Thermal Power is ≥ 28.3% and ≤ 90% when MCPR is less than the limit specified in the COLR and when Thermal Power is ≥ 90% when MCPR is less than the limit specified in the COLR. The proposed Applicability was determined by the ARTS analysis for the RBM (NEDC-32162P, Rev.1, "Maximum Extended Load Line Limit and ART Improvement Program Analyses for Peach Bottoms Atomic Power Station Unit 2 and 3" and GE-NE-901-0293, Rev.1, "APRM, RBM, and Technical Specifications (ARTS) Setpoint Calculations for Philadelphia Electric Company Peach Bottom 2,3"). This change is consistent with BWR Standard Technical Specifications, NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, M_3, M_4, and M_5 Labeled Comments/Discussions for ITS 3.3.2.1) - continued

M_4 Proposed Specification 3.3.2.1 will include an additional surveillance (SR 3.3.2.1.6) to verify every 24 months that the Rod Worth Minimizer (RWM) is not bypassed when Thermal Power is ≤ 10%. Both existing Specification 3.3.B.3.b and proposed Specification 3.3.2.1 (Table 3.3.2.1-1 Footnote (f)) specify that the RWM function is only required to be Operable when Thermal Power is less than 10% and the RWM is automatically bypassed when power is above 10%. However, the existing specifications do not have an explicit requirement to verify the setpoint of the RWM bypass feature. This change is consistent with BWR Standard Technical Specifications, NUREG-1433.

M_5 This SR has been deleted since it is covered by the combination of proposed SRs 3.3.2.1.1, 3.3.2.1.4, and 3.3.2.1.5. In addition, these SRs are performed at a Frequency no greater than 184 days, therefore this change is considered more restrictive.

(M_1 Labeled Comment/Discussion for ITS 3.3.2.2)

M_1 Proposed LCO 3.3.2.2, Feedwater and Main Turbine High Water Level Trip Instrumentation, and the associated Conditions, Required Actions, Completion Times, and Surveillance Requirements have been added. The feedwater and main turbine high water level trip instrumentation is assumed to be capable of providing feedwater and main turbine high water level trips in the design basis transient analysis for a feedwater controller failure, maximum demand event. Justification for the allowable out of service times for inoperable instrument channels and the minimum frequency for channel functional tests is provided by GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications" (SER dated July 21, 1992). Confirmation of the applicability of GENE-770-06-1 to PBAPS is documented in Attachment 1 to the 10 CFR 50.59 Safety Assessment for Technical Specification Change Request 90-03. The proposed 24 month frequency for channel calibration and the associated allowable value leaves the channel adjusted to account for instrument drift between successive calibrations, consistent with the assumptions of the current plant specific setpoint methodology. This proposed additional restriction is consistent with NUREG-1433 and helps ensure the safety analysis assumptions are maintained.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)
(M_1 and M_2 Labeled Comments/Discussions for ITS 3.3.3.1)

M_1 Requirements for PCIV position indication have been added. These requirements include an LCO, Applicability, Actions, and Surveillance Requirements. Requirements for PCIV position indication are included consistent with NUREG-1433 guidelines to include all Type A and Category 1 PAM instruments.

M_2 The Applicability for the oxygen analyzers has been expanded from "power operation" to "Modes 1 and 2." This change achieves consistency with the CAD System and NUREG-1433 and represents an additional restriction on plant operations.

(M_1 Labeled Comment/Discussion for ITS 3.3.3.2)

M_1 Existing Specifications 3.11.C and 4.11.C identify requirements for the Emergency Shutdown Control Panel. These requirements are limited to an LCO that the Emergency Shutdown Control Panels be secured at all times and Surveillances to verify by visual inspection once per week that the panels are secured and to perform an electrical check once per refueling outage. A new Specification, 3.3.3.2, Remote Shutdown System will be added to require that the appropriate number of Functions are available to shutdown and control the plant if the control room must be evacuated. Appropriate Actions and Surveillance Requirements are also being added. This change is consistent with BWR Standard Technical Specifications, NUREG-1433, and represents an additional restriction on plant operations.

(M_1 Labeled Comment/Discussion for ITS 3.3.4.1)

M_1 The required Frequency for performance of an ATWS-RPT Channel Check will be increased from once per day specified in existing specification 4.2.G (Table 4.2.G) to the once per 12 hours specified in proposed SR 3.3.4.1.1. The purpose of the channel check is to ensure that a gross failure of instrumentation has not occurred. Thus, performance of the channel check guarantees that undetected outright channel failure is limited to 12 hours. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)
(M_1, M_2, and M_3 Labeled Comments/Discussions for ITS 3.3.5.1)

M_1 The proposed change adds new Functions to the ECCS Instrumentation Table. Along with these added Functions are added Actions and Surveillance Requirements. The addition of new requirements constitute a more restrictive change. This change is consistent with NUREG-1433. Below is a list of the added Functions, and Surveillance Requirements and their associated frequency. The list is categorized by ECCS System.

Core Spray

1.d Core Spray Pump Discharge Flow—Low (Bypass):

SR 3.3.5.1.2 Channel Functional Test - 92 days
SR 3.3.5.1.4 Channel Calibration - 24 months

Low Pressure Coolant Injection

2.g Low Pressure Coolant Injection Pump Discharge Flow—Low (Bypass)

SR 3.3.5.1.2 Channel Functional Test - 92 days
SR 3.3.5.1.4 Channel Calibration - 24 months
SR 3.3.5.1.5 Logic System Functional Test - 24 months

High Pressure Coolant Injection

3.f High Pressure Coolant Injection Pump Discharge Flow—Low (Bypass)

SR 3.3.5.1.2 Channel Functional Test - 92 days
SR 3.3.5.1.4 Channel Calibration - 24 months
SR 3.3.5.1.5 Logic System Functional Test - 24 months

Automatic Depressurization System

4.d Reactor Vessel Water Level—Low Low Low (Level 1), (Permissive)

SR 3.3.5.1.1 Channel Check - 12 hours
SR 3.3.5.1.2 Channel Functional Test - 92 days
SR 3.3.5.1.4 Channel Calibration - 24 months
SR 3.3.5.1.5 Logic System Functional Test - 24 months

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, and M_3 Labeled Comments/Discussions for ITS 3.3.5.1)

M_1 (cont'd) 5.d Reactor Vessel Water Level—Low Low Low (Level 1), (Permissive)

SR 3.3.5.1.1	Channel Check - 12 hours
SR 3.3.5.1.2	Channel Functional Test - 92 days
SR 3.3.5.1.4	Channel Calibration - 24 months
SR 3.3.5.1.5	Logic System Functional Test - 24 months

M_2 This change increases the Surveillance Frequency for the Channel Check from daily to 12 hours. The Channel Check performed every 12 hours ensures that a gross failure of instrumentation has not occurred. Thus, performance of the Channel Check guarantees that undetected outright channel failure is limited to 12 hours. Increasing Surveillance Frequencies constitutes a more restrictive change. This change is consistent with NUREG-1433.

M_3 This change proposes to require 8 channels of RHR pump discharge pressure instruments. The current Specification from Table 3.2.B requires 2 channels per trip system and specifies that there are 4 channels by design. Increasing the number of channels required to 8 channels per trip system is consistent with the PBAPS design (8 RHR pump discharge pressure inputs per trip system - 2 per pump). This change increases the number of channels required which constitutes a more restrictive change.

(M_1 and M_2 Labeled Comments/Discussions for ITS 3.3.5.2)

M_1 This change increases the Surveillance Frequency for the Channel Check from daily to 12 hours. The Channel Check performed every 12 hours ensures that a gross failure of instrumentation has not occurred. Thus, performance of the Channel Check guarantees that undetected outright channel failure is limited to 12 hours. Increasing Surveillance Frequencies constitutes a more restrictive change. This change is consistent with NUREG-1433.

M_2 This proposed change adds a requirement to perform a Logic System Functional Test of the RCIC System. The current requirement only applies to the RCIC System Auto Isolation Function. Since this change adds a new requirement, it is classified as a more restrictive change. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)
(M_1, M_2, M_3, M_4, M_5, and M_6 Labeled Comments/Discussions for ITS 3.3.6.1)

M_1 The proposed change adds new Functions to the Primary Containment Isolation Instrumentation Table. Along with these additional Functions are the associated Conditions, Required Actions and Surveillance Requirements. The addition of new requirements constitute a more restrictive change. This change is consistent with NUREG-1433. Below is a list of the added Functions, and Surveillance Requirements and associated frequency. The list is categorized by ITS Containment Isolation Group.

High Pressure Coolant Injection (HPCI) Isolation

3.d Drywell Pressure—High

SR 3.3.6.1.1	Channel Check - 12 hours
SR 3.3.6.1.2	Channel Functional Test - 92 days
SR 3.3.6.1.5	Channel Calibration - 24 months
SR 3.3.6.1.7	Logic System Functional Test - 24 months

Reactor Core Isolation Cooling (RCIC) Isolation

4.d Drywell Pressure—High

SR 3.3.6.1.1	Channel Check - 12 hours
SR 3.3.6.1.2	Channel Functional Test - 92 days
SR 3.3.6.1.5	Channel Calibration - 24 months
SR 3.3.6.1.7	Logic System Functional Test - 24 months

Reactor Water Cleanup (RWCU) System Isolation

5.b SLC System Initiation

SR 3.3.6.1.7	Logic System Functional Test - 24 months

5.c Reactor Water Level—Low

SR 3.3.6.1.1	Channel Check - 12 hours
SR 3.3.6.1.2	Channel Functional Test - 92 days
SR 3.3.6.1.5	Channel Calibration - 24 months
SR 3.3.6.1.7	Logic System Functional Test - 24 months

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, M_3, M_4, M_5, and M_6 Labeled Comments/Discussions for ITS 3.3.6.1)

M_1 (cont'd) Shutdown Cooling System Isolation

6.b Reactor Water Level—Low

SR 3.3.6.1.1	Channel Check - 12 hours
SR 3.3.6.1.2	Channel Functional Test - 92 days
SR 3.3.6.1.5	Channel Calibration - 24 months
SR 3.3.6.1.7	Logic System Functional Test - 24 months

M_2 Proposed Specification 3.3.6.1 will increase the Frequency of the Channel Checks currently specified in Tables 4.2.A, 4.2.B, and 4.2.D from once per day to once per 12 hours and for Table 4.2.B, Item 12, adds a Channel Check requirement once per 12 hours (currently none is required). This change adds additional requirements and it constitutes a more restrictive change. This change is consistent with the BWR Standard Technical Specifications, NUREG-1433.

M_3 Proposed Specification 3.3.6.1 will include more restrictive Required Action if the Refuel Area Ventilation Exhaust Radiation—High (proposed Function 2.e) or the Reactor Building Ventilation Exhaust Radiation—High (proposed Function 2.d) have fewer than the minimum required number of Operable channels and the channels are not placed in trip within 24 hours. Currently, Specification 3.2.D (Table 3.2.D) requires only that operation of refueling equipment cease, secondary containment be isolated and SGT started. Under identical conditions, proposed Specification 3.3.6.1 (Condition H) will require that the reactor be in Mode 3 within 12 hours and Mode 4 within 36 hours. Since this change requires placing the reactor outside of the applicable Modes for these instruments, the proposed change is more restrictive. This change is consistent with the BWR Standard Technical Specifications, NUREG-1433.

M_4 Currently, Surveillance Requirements for the PCI Functions associated with high drywell pressure, reactor low water level, and MSL high radiation are specified in Table 4.1.2 (Table 4.2.B, Note 5) with the SRs for the Reactor Protection System. Table 4.1.2 requires Channel Calibrations (Proposed SR 3.3.6.1.3 and SR 3.3.6.1.5). Proposed Specification 3.3.6.1 will add new requirements for Channel Functional Tests (Proposed SR 3.3.6.1.2 for Functions 2.a and 2.b) and Logic System Functional Tests (Proposed SR 3.3.6.1.7 for Functions 1.d, 2.a, 2.b, and 7.a). This change is consistent with the BWR Standard Technical Specifications, NUREG-1433. This additional requirement will affect the following PCI Functions:

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, M_3, M_4, M_5, and M_6 Labeled Comments/Discussions for ITS 3.3.6.1)

M_4 (cont'd)

Main Steam Line Isolation

1.d Main Steam Line High Radiation

SR	3.3.6.1.1	Channel Check - 12 hours
SR	3.3.6.1.7	Logic System Functional Test - 24 months

Primary Containment Isolation

2.a Reactor Vessel Water Level—Low

SR	3.3.6.1.1	Channel Check - 12 hours
SR	3.3.6.1.2	Channel Functional Test - 92 days
SR	3.3.6.1.7	Logic System Functional Test - 24 months

2.b Drywell Pressure—High

SR	3.3.6.1.1	Channel Check - 12 hours
SR	3.3.6.1.2	Channel Functional Test - 92 days
SR	3.3.6.1.7	Logic System Functional Test - 24 months

Feedwater Recirculation Isolation

7.a Reactor Pressure—High

SR	3.3.6.1.7	Logic System Functional Test - 24 months

M_5 Existing Table 3.2.A (Item 6 and associated Note 2.B) requires that the Main Steam Line be isolated within 12 hours of the determination that there are fewer than the minimum required number of Operable or tripped channels. Under the identical conditions, proposed Specification 3.3.6.1-1 (Table 3.3.6.1-1, Function 1.b, Condition E) will require that the reactor be in Mode 2 within 6 hours. This change is acceptable because it places the reactor outside the Mode of Applicability in less time than the current Specification. This change is consistent with the BWR Standard Technical Specifications, NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, M_3, M_4, M_5, and M_6 Labeled Comments/Discussions for ITS 3.3.6.1) - continued

M_6 The proposed change adds new Surveillance Requirement Functions to the Primary Containment Isolation Instrumentation Table. The addition of new requirements constitute a more restrictive change. This change is consistent with NUREG-1433. Below is a list of the added Surveillance Requirements and associated Frequency. The list is categorized by ITS Containment Isolation Group.

Primary Containment Isolation

2.c SR 3.3.6.1.7, Logic System Functional Test - 24 months
2.d SR 3.3.6.1.7, Logic System Functional Test - 24 months
2.e SR 3.3.6.1.7, Logic System Functional Test - 24 months

(M_1, M_2, and M_3 Labeled Comments/Discussions for ITS 3.3.6.2)

M_1 This change modifies current Technical Specification Action A (Table 3.2.D) to include also discontinuing OPDRV (as a result of declaring the associated secondary containment isolation valves and standby gas treatment subsystem inoperable and taking the appropriate actions) if the channel is not placed in trip (placing the plant in a non-applicable Mode or Condition) due to specifying OPDRVs as an applicable Condition. Currently, only operation of the refueling equipment has to cease. The addition of OPDRVs to the applicable Conditions further ensures that offsite dose limits will not be exceeded should fuel damage result from a vessel draindown event by discontinuing operations which could initiate an event. This change constitutes a more restrictive change. This change is consistent with NUREG-1433.

M_2 The proposed change adds two new Functions (Functions 1 and 2 as listed below). Along with these added Functions, Actions (A, B, and C) and Surveillance Requirements are provided. Action A requires the channel to be placed in trip if one or more channels are inoperable. The allowed outage time for Function 1 is 12 hours and for Function 2 is 12 hours. These times are based on the analyses in NEDC-31677P-A and NEDC-30851P-A. One hour is allowed to restore a loss of Function (Action B). If these requirements are not met within the Completion Times then Action C is entered which requires the associated secondary containment penetration flow path to be isolated or the SCIVs to be declared inoperable, and the SGT to be A

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, and M_3 Labeled Comments/Discussions for ITS 3.3.6.2)

M_2 (cont'd) started or the SGT to be declared inoperable. Below is a list of the added Surveillance Requirements for each Function. The addition of new requirements (Functions with Actions and Surveillances) constitute a more restrictive change. This change is consistent with NUREG-1433.

1. Reactor Vessel Water Level—Low (Level 3)

Modes 1, 2, 3, and during operations with a potential for draining the reactor vessel:

SR 3.3.6.2.1	Channel Check - 12 hours
SR 3.3.6.2.2	Channel Functional Test - 92 days
SR 3.3.6.2.4	Channel Calibration - 24 months
SR 3.3.6.2.5	Logic System Functional Test - 24 months

2. Drywell Pressure—High

Modes 1, 2, and 3:

SR 3.3.6.2.1	Channel Check - 12 hours
SR 3.3.6.2.2	Channel Functional Test - 92 days
SR 3.3.6.2.4	Channel Calibration - 24 months
SR 3.3.6.2.5	Logic System Functional Test - 24 months

M_3 This change increases the Surveillance Frequency for the Channel Check from daily to 12 hours. The Channel Check performed every 12 hours ensures that a gross failure of instrumentation has not occurred. Increasing Surveillance Frequencies constitutes a more restrictive change. This change is consistent with NUREG-1433.

(M_1, M_2, M_3, and M_4 Labeled Comments/Discussions for ITS 3.3.7.1)

M_1 The Frequency of the Channel Check requirement for the Control Room Air Intake Radiation—High Function has been increased from once per day to once per 12 hours. This change is consistent with NUREG-1433 and represents an additional restriction on plant operations.

M_2 Current Specification 3.11.A.5.b requires if one channel is inoperable or in trip in both trip systems that emergency ventilation be initiated and maintained, but specifies no Completion Time for the action. The proposed Action for this same Condition (Required Action A.1) requires the associated MCREV subsystem be declared inoperable within 1 hour from discovery that this Condition

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, M_3, and M_4 Labeled Comments/Discussions for ITS 3.3.7.1)

M_2 (cont'd) exists. The MCREV Specification (LCO 3.7.4) then provides the actions for the associated MCREV subsystems. The change is considered an additional restriction on plant operation since it provides a specific time period for completing the actions. In addition, declaring the associated MCREV subsystems inoperable will result in having to place the plant in a non-applicable Mode or Condition.

M_3 Current Specification 3.11.A.5.a specifies that "one radiation monitoring channel may be inoperable for 7 days, as long as the remaining radiation monitoring channel maintains the capability of initiating emergency ventilation on any designed trip functions." Proposed LCO 3.3.7.1, Condition A, will require that an inoperable channel be placed in trip within 6 hours in addition to the requirement that the associated MCREV subsystem be declared inoperable within one hour of discovery of loss of initiation capability in both trip systems. Although proposed LCO 3.3.7.1 permits operation with one channel in trip for an indefinite period (instead of 7 days as allowed by existing 3.11.A.5.a), the requirement that the inoperable channel be placed in trip within 6 hours is more restrictive because it re-establishes the capability to tolerate a single failure of an instrument channel within 6 hours. The proposed change is consistent with the analysis in GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications" (SER dated July 21, 1992). Confirmation of the applicability of GENE-770-06-1 to PBAPS for the MCREV system is documented in Technical Specification Change Request 90-03. This change is consistent with NUREG-1433.

M_4 Current Specification 3.11.A.7 requires that if the actions of existing Specification 3.11.A.5 or 3.11.A.6 cannot be met the MCREV be manually initiated and maintained, but specifies no Completion Time for this action. The proposed Actions for the same Conditions (Required Actions B.1 and B.2) require the associated MCREV subsystem to be initiated within 1 hour or to declare the associated MCREV subsystem inoperable within 1 hour. Declaring the associated MCREV subsystem inoperable within 1 hour results in having to take the actions of Specification 3.7.4 for the associated subsystems. This change is considered an additional restriction on plant operation since it provides a specific time for completing the actions. In addition, declaring the associated MCREV subsystems inoperable will result in having to place the plant in a non-applicable Mode or Condition.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)
(M_1, M_2, M_3, and M_4 Labeled Comments/Discussions for ITS 3.3.8.1)

M_1 The proposed change adds a new subfunction to each of the Degraded Voltage Functions in the LOP Instrumentation Table. The added Functions (2.b, 3.b, 4.b, and 5.b) are the Time Delays for the DG start signal on a degraded voltage condition. Along with these added subfunctions are added Actions and Surveillance Requirements. The addition of new requirements constitute a more restrictive change. This change is consistent with NUREG-1433. Below is a list of the added Surveillance Requirements and associated Frequency.

SR 3.3.8.1.1 Channel Functional Test - 31 days
SR 3.3.8.1.2 Channel Calibration - 18 months
SR 3.3.8.1.4 Logic System Functional Test - 24 months

M_2 The proposed change adds a new Surveillance Requirement (SR 3.3.8.1.4, Logic System Functional Test) to the LOP Instrumentation Functions. The change adds SR 3.3.8.1.4 for the Loss of Voltage and Degraded Voltage Functions. The addition of new requirements constitutes a more restrictive change. This change is consistent with NUREG-1433.

M_3 Since Unit 2(3) requires some equipment powered from Unit 3(2) sources to be OPERABLE, LOP instruments that transfer offsite circuits and start DGs due to loss of power to a Unit 3(2) emergency bus is needed. Therefore, each unit now requires the opposite units LOP instrumentation Functions 1, 2, 3, and 5 to be OPERABLE. Appropriate Actions and SRs have also been added. The addition of new requirements constitutes a more restrictive change.

M_4 A new Note has been added to Actions A, B, and C. This note will require an offsite circuit to be declared inoperable, if placing a channel in trip results in inoperability of the offsite circuit. The addition of new requirements constitutes a more restrictive change.

(M_1, M_2, and M_3 Labeled Comments/Discussions for ITS 3.3.8.2)

M_1 If one RPS electric power monitoring assembly per RPS MG set or alternate power supply is inoperable or bypassed and not restored within 72 hours, current Specifications 3.1.D.1 and 3.1.D.2 allow 30 minutes to transfer the RPS bus to the alternate source or de-energize the bus. However, the proposed change for this condition would require placing the plant in a non-applicable Mode or

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, and M_3 Labeled Comments/Discussions for ITS 3.3.8.2)

M_1 (cont'd) Condition (Actions C and D) if transfer or deenergization is not accomplished within the 72 hour restoration time. As such, the change is an additional restriction on plant operation and is consistent with NUREG-1433.

M_2 An additional Surveillance has been provided (SR 3.3.8.2.4) to perform a system functional test once per 24 months. This Surveillance demonstrates that with a system actuation signal, the logic of the system will automatically trip open the associated RPS electric power monitoring assembly. This change represents an additional restriction on plant operation.

M_3 Time delay setting requirements have been added for the undervoltage and overvoltage protective devices of the RPS MG set and the underfrequency and overvoltage protective devices of the RPS alternate power supply. These devices have adjustable time delay settings. This change represents an additional restriction on plant operations necessary to ensure no abnormal voltage or frequency condition can preclude the function of RPS bus powered components.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change provides more stringent requirements than previously existed in the Technical Specifications. The more stringent requirements will not result in operation that will increase the probability of initiating an analyzed event. If anything the new requirements may decrease the probability or consequences of an analyzed event by incorporating the more restrictive changes discussed above. The change will not alter assumptions relative to mitigation of an accident or transient event. The more restrictive requirements will not alter the operation of process variables, structures, systems, or components as described in the safety analyses. The change has been confirmed to ensure no previously evaluated accident has been adversely affected. Therefore, the change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   Making existing requirements more restrictive and adding more restrictive requirements to the Technical Specifications will not alter the plant configuration (no new or different type of equipment will be installed) or make changes in methods governing normal plant operation. The change does impose different requirements. However, the change is consistent with assumptions made in the safety analyses. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   Adding new requirements and making existing ones more restrictive either increases or does not affect the margin of safety. The change does not impact any safety analysis assumptions. As such, no question of safety is involved. Therefore, this change will not involve a significant reduction in a margin of safety.

NO SIGNIFICANT HAZARDS CONSIDERATIONS
SECTION 3.3--INSTRUMENTATION

TECHNICAL CHANGES - RELOCATIONS

This proposed change relocates requirements from the Technical Specifications to a licensee controlled document. These changes are labeled "Technical Changes - Relocations." These changes are listed below.

(R_1, R_2, R_3, R_4, R_5, R_6, R_7, R_8, R_9, R_{10}, R_{11}, R_{12}, and R_{13} Labeled Comments/Discussions for ITS 3.3.1.1)

R_1 This change proposes to relocate the terms and definitions (S, W, and ΔW) for the setting of the APRM Flow Biased High Scram equation. This function monitors neutron flux to approximate the thermal power being transferred to the reactor coolant. These definitions will be relocated to a licensee controlled document. Any changes to these definitions will undergo a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_2 This change proposes to relocate the APRM Flow Biased Scram Relationship to Normal Operating Conditions Figure to a licensee controlled document. Any changes to this curve will undergo a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_3 The specific design value (50 milliseconds) for the RPS response time acceptance criterion is proposed to be relocated to the PBAPS UFSAR consistent with NRC Generic Letter 93-08. This is considered to be acceptable since the requirements of SR 3.3.1.1.18 are adequate to ensure the affected RPS functions are tested to ensure response times are maintained within required limits. SR 3.3.1.1.18 of Specification 3.3.1.1 requires RPS response times to be verified within limits once per 24 months. If the requirements of SR 3.3.1.1.18 are not satisfied, SR 3.0.1 requires the affected channels of the RPS to be declared inoperable and the ACTIONS of Specification 3.3.1.1 entered. In addition, placing the RPS response time acceptance criterion in the UFSAR provides assurance that it will be maintained. The 10 CFR 50.59 control process for the UFSAR ensures that the requirement is appropriately maintained. As a result, the requirements proposed to be relocated are not required to be included in the Technical Specifications to ensure required RPS response time testing is performed and RPS response times are maintained within required limits. B

R_4 This change proposes to relocate the details of the performance of the Channel Functional Test of the Mode Switch in Shutdown Function which states to place the Mode Switch in Shutdown. The specifics of the performance of the test will be relocated to the plant surveillance procedures. Details of the performance of procedures have been relocated to licensee controlled documents. Any changes to this requirement will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, R_4, R_5, R_6, R_7, R_8, R_9, R_{10}, R_{11}, R_{12}, and R_{13} Labeled Comments/Discussions for ITS 3.3.1.1) - continued

R_5 This change relocates the requirement that an APRM will be considered Operable if there are at least 2 LPRM inputs per level and at least 14 LPRM inputs of the normal complement. These requirements will be relocated to the Bases. Any changes to these requirements (consistent with changes to the Bases) will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_6 This change proposes to relocate the number of instrument channels provided by design column for each Function. This information will be relocated to the Bases of the proposed Technical Specifications. Any changes to this requirement will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_7 This change proposes to relocate the statement regarding the functions design which permits closure of any two lines without a scram being initiated. This information will be relocated to the UFSAR. Any changes to this requirement will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_8 This change proposes to relocate Note 5, "IRM's are bypassed when APRM's are onscale and the reactor mode switch is in the run position," which is associated with the IRM High Flux and IRM Inoperative Functions and Note 10, "the APRM downscale trip is automatically bypassed when the IRM instrumentation is operable and not high," which is associated with the APRM Downscale Function. These notes will be relocated to plant procedures. Any changes to these requirements will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_9 This change proposes to relocate discussions/specifics (e.g., what's required to be tested for each Function, equipment required for the test, how to perform the test, etc.) concerning surveillance tests to the specific plant surveillance test procedure. This change is consistent with NUREG-1433. Any changes to these requirements will require a 10 CFR 50.59 review.

R_{10} This change proposes to relocate the requirements of Note 3, related to the Minimum Frequency column of current Table 4.1.1, to a licensee controlled document. This requirement specifies that "functional tests are not required on the part of the system that is not required to be operable or are tripped. If tests are missed on parts not required to be operable or are tripped, then they shall be performed prior to returning the system to an operable status."

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, R_4, R_5, R_6, R_7, R_8, R_9, R_{10}, R_{11}, R_{12}, and R_{13} Labeled Comments/Discussions for ITS 3.3.1.1) - continued

R_{10} (cont'd) This requirement will be relocated to a licensee controlled document such as the procedure governing performance of surveillance tests. Any changes to this requirement will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433. In addition, proposed SR 3.0.1 and the associated Bases will also ensure this current requirement is maintained.

R_{11} This change proposes to relocate the requirements for a Channel Functional Test after maintenance is performed to a licensee controlled document (e.g., post maintenance procedures). Post maintenance requirements are being relocated out of the Technical Specifications. Any changes to the current post maintenance testing requirements for the RPS Test Switch will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_{12} This change proposes to relocate the current "Trip Level Setting" column in current Technical Specifications Table 3.3.1 and replace it with an "Allowable Value" column in the proposed Technical Specifications Table 3.3.1.1-1. Trip setpoints are an operational detail that is not directly related to the Operability of the instrumentation and will be relocated to a licensee controlled document. The Allowable Value is the required limitation for the parameter and this value will be inserted in the table. Any change to the trip setpoints will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_{13} System operational details (when not to place in trip) have been relocated to the Bases and procedures. These details are unnecessary in the LCO and can be adequately controlled in the Bases and procedures. Changes to the Bases will be controlled by the provisions of the Bases Control Process in Chapter 5 of the Technical Specifications. Changes to procedures will be controlled by the provisions of 10 CFR 50.59.

(R_1, and R_2 Labeled Comments/Discussions for ITS 3.3.1.2)

R_1 Existing Specification 3.10.B.1.a requires that SRMs be inserted to the normal operating level during core alterations. Proposed specifications have requirements for minimum SRM count rate during Core Alterations but do not require that the SRMs be fully inserted. This existing requirement is being relocated to plant procedures to provide assurance it will be maintained. Changes to these procedures will be controlled by 10 CFR 50.59.

TECHNICAL CHANGES - RELOCATIONS
(R_1, and R_2 Labeled Comments/Discussions for ITS 3.3.1.2) - continued

R_2 Existing Specification 3.10.B.1.b requires that the SRM minimum count rate during Core Alterations must be achieved with all rods fully inserted in the core. Proposed specifications have requirements for minimum SRM count rate during Core Alterations but do not specifically require that the control rods be fully inserted. This existing requirement is being relocated to plant procedures to provide assurance it will be maintained. Changes to these procedures will be controlled by 10 CFR 50.59.

(R_1, R_2, R_3, R_4, and R_5 Labeled Comments/Discussions for ITS 3.3.2.1)

R_1 Existing Specifications 2.1.B, 3.2.C.2.1, and 4.2.C.2.1 include the Safety Limits, LCOs and SRs for Rod Block functions associated with the APRMs, IRMs, SRMs, and Scram Discharge Volume Level. These requirements are being relocated to PBAPS plant procedures and will be controlled in accordance with 10 CFR 50.59. Only the power-biased local power RBM functions are being retained in Technical Specifications. The APRM, IRM, SRM, and Scram Discharge Volume (SDV) rod blocks are intended to prevent control rod withdrawal when plant conditions make such withdrawal imprudent. However, there are no safety analyses that depend upon these rod blocks to prevent, mitigate or establish initial conditions for design basis accidents or transients. The evaluation summarized in NEDO 31466 determined that the loss of the APRM, IRM, SRM, and scram discharge volume rod blocks would be a non-significant risk contributor to core damage frequency and offsite releases. The results of this evaluation have also been determined to be applicable to PBAPS Units 2 and 3. Therefore, this instrumentation did not satisfy the NRC Policy Statement on Technical Specification Screening Criteria for inclusion in the Technical Specifications and will be relocated to plant procedures and controlled in accordance with 10 CFR 50.59.

R_2 Existing Table 3.2.C includes the "Number of Instrument Channels Provided by Design." This information will be relocated to the Applicable Safety Analyses section of the proposed Bases for Specification 3.3.2.1. This change is consistent with BWR Standard Technical Specifications, NUREG-1433.

R_3 Existing Table 4.2.C, Notes 4 and 6 contain details regarding the performance of Rod Block Monitor Surveillance Tests. Details of the methods for performing Surveillance Tests will be relocated to plant procedures and will be controlled in accordance with 10 CFR 50.59.

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, R_4, and R_5 Labeled Comments/Discussions for ITS 3.3.2.1) - continued

R_4 Existing Specifications 4.3.B.3.b.1.a, b, and c contain details related to the performance of the Rod Worth Minimizer (RWM) Channel Functional Test. Details of the methods for performing Surveillance Tests will be relocated to plant procedures and will be controlled in accordance with 10 CFR 50.59.

R_5 Existing Specification 4.2.C.2 (Table 4.2.C) requires an "Instrument Check" of the Rod Block Monitor once/day. This test is performed by comparison of redundant channels as a simple check of instrument performance. NUREG-1433 has no equivalent check for the RBM so performance of the daily "Instrument Check" of the Rod Block Monitor will be relocated to plant procedures and will be controlled in accordance with 10 CFR 50.59.

(R_1, R_2, R_3, and R_4 Labeled Comments/Discussions for ITS 3.3.3.1)

R_1 The NRC position on application of the deterministic screening criteria to PAM instrumentation is documented in a letter dated May 7, 1988 from T.E. Murley (NRC) to R.F. Janecek (BWROG). The position was that the PAM table in Technical Specifications should contain, on a plant specific basis, all Regulatory Guide 1.97 Type A instruments and all Category 1 instruments. Accordingly, this position has been applied to the PBAPS Unit 2 and 3 Regulatory Guide 1.97 instruments. Those instruments meeting this criteria have remained in Technical Specifications. The instruments not meeting this criteria, and their associated Technical Specification requirements have been relocated to plant controlled documents, controlled using 10 CFR 50.59. For PAM instrumentation, that does not satisfy the deterministic screening criteria, their loss is not considered risk significant since the variable they monitor did not qualify as a Type A or Category 1 variable (one that is important to safety or needed by the operator to perform necessary manual actions). Therefore, consistent with NUREG-1433, these criteria have been applied to the PBAPS specific PAM instrumentation and the following instruments and their associated requirements are being relocated to plant controlled documents, controlled by 10 CFR 50.59.

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, and R_4 Labeled Comments/Discussions for ITS 3.3.3.1)

R_1 (cont'd)
1. Reactor Water Level (Narrow Range)
2. Drywell Pressure
3. Drywell Temperature
4. Suppression Chamber Water Level (Narrow Range)
5. Control Rod Position
6. Neutron Monitoring
7. Safety-Relief Valve Position Indication
8. Main Stack High Range Radiation Monitor
9. Reactor Building Roof Vent High Range Radiation Monitor

R_2 Details of the system Operability requirements and description of the instruments are relocated to the Bases, procedures, and the UFSAR. Placing this information in these documents provides assurance it will be maintained. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Process in Chapter 5 of the Technical Specifications.

R_3 Details of the performance of surveillances have been relocated to plant procedures. Placing these details in procedures provides assurance they will be maintained since changes to these procedures is controlled by 10 CFR 50.59. This change is consistent with NUREG-1433.

R_4 This Surveillance is being relocated to plant procedures since it is currently performed every time the CAD System is tested per existing Specification 4.7.A.6.a. As such, it does not need to be specified as a specific Surveillance Requirement. If during use of the system it was found to be inoperable, the appropriate Actions would be taken. This change is consistent with NUREG-1433.

(R_1 Labeled Comment/Discussion for ITS 3.3.3.2)

R_1 Existing Specifications 3.11.C and 4.11.C requires that the Emergency Shutdown Control Panels be secured at all times and that this status be verified once per week by visual inspection. Keeping the Emergency Shutdown Control Panels secured is intended to prevent inadvertent operation. These requirements are being relocated to PBAPS plant procedures and will be controlled in accordance with 10 CFR 50.59. There are no safety analyses that depend upon these panels being secured to prevent, mitigate or establish initial conditions for design basis accidents or transients.

TECHNICAL CHANGES - RELOCATIONS (continued)
(R_1, R_2, R_3, R_4, R_5, and R_6 Labeled Comments/Discussions for ITS 3.3.4.1)

R_1 Existing Specification 3.2.G establishes requirements for the Anticipated Transient Without Scram (ATWS) function: "Alternate Rod Insertion and Recirculation Pump Trip." Proposed Specification 3.3.4.1 will maintain the Technical Specifications requirement for the recirculation pump trip. However, the ATWS Alternate Rod Insertion (ARI) function, serving only as a backup to the Reactor Protection System Scram function, did not satisfy the NRC Policy Statement on Technical Specification Screening Criteria for inclusion in the Technical Specifications. As such, ARI function requirements are being relocated to a licensee controlled document. In addition to being controlled in accordance with 10 CFR 50.59, the ARI function is required by and must meet the requirements of 10 CFR 50.62 and will be maintained in accordance with Appendix B to 10 CFR 50 per NRC Generic Letter 85-06, "Quality Assurance Guidance for ATWS Equipment that is not Safety-Related." This proposed change is consistent with NUREG-1433.

R_2 Existing Specification 3.2.G establishes the requirement that the Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) function have "manual" actuation capability. However, manual actuation of the ATWS-RPT function is not credited in the ATWS analysis; as such, ATWS-RPT manual actuation function requirements are being relocated to the a licensee controlled document. Requirements for the manual actuation capability of the ATWS-RPT function will be controlled in accordance with 10 CFR 50.59. This proposed change is consistent with NUREG-1433.

R_3 Existing Specification 3.2.G includes the phrase "automatic actuation of logic and actuation devices" when describing the features of the ATWS-RPT function that must be Operable for the ATWS-RPT function to be Operable. This type of information will be relocated to the Bases in the section entitled Applicable Safety Analyses, LCO, and Applicability and will be controlled in accordance with 10 CFR 50.59. This change is consistent with NUREG-1433.

R_4 Existing Specification 3.2.G (Table 3.2.G, Column 4) includes the "Number of Instrument Channels Provided by Design per Trip System." Additionally, existing Specification 4.2.G (Table 4.2.G Note 2) identifies the ATWS-RPT function instruments as the same instruments used by the Core and Containment Cooling Systems. This type of information will be relocated to plant procedures and design documents and will be controlled in accordance with 10 CFR 50.59. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, R_4, R_5, and R_6 Labeled Comments/Discussions for ITS 3.3.4.1) - continued

R_5 Existing Specification 4.2.G (Table 4.2.G including Note 2) establishes a requirement to perform every 3 months a Logic System Functional Test of the ATWS-RPT function without tripping the recirculation pump breaker. This requirement was placed in PBAPS Technical Specifications as a result of NRC SER dated 12/21/1988 that evaluated PBAPS compliance with the ATWS rule and recommended that the ATWS trip units and logic systems be tested once per quarter. Proposed SR 3.3.4.1.2 and 3.3.4.1.5 will require an ATWS-RPT Channel Functional Test once per 92 days and a Logic System Functional Test once per 24 months. Performance every 3 months of a Logic System Functional Test of the ATWS-RPT function without tripping the recirculation pump breaker provides additional assurance of proper operation of the trip units and logic systems but is not required by NUREG-1433. Since this additional requirement for testing can be adequately controlled by administrative procedures, this testing requirement will be relocated to plant procedures and controlled in accordance with 10 CFR 50.59. This change is consistent with NUREG-1433.

R_6 System operational details (when not to place in trip) have been relocated to the Bases and procedures. These details are unnecessary in the LCO and can be adequately controlled in the Bases and procedures. Changes to the Bases will be controlled by the provisions of the Bases Control Process in Chapter 5 of the Technical Specifications. Changes to procedures will be controlled by the provisions of 10 CFR 50.59.

(R_1, R_2, R_3, R_4, R_5, R_6, and R_7 Labeled Comments/Discussions for ITS 3.3.5.1)

R_1 The change will relocate items which are procedural in nature (e.g. conversions, specific instructions, etc.) to procedures. These items will be retained and will require a 10 CFR 50.59 review in order to be changed. This change is consistent with NUREG-1433.

R_2 This change proposes to relocate the current "Trip Level Setting" column in current Technical Specifications Table 3.2.B and replace it with an "Allowable Value" column in the proposed Technical Specifications Table 3.3.5.1-1. Trip setpoints are an operational

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, R_4, R_5, R_6, and R_7 Labeled Comments/Discussions for ITS 3.3.5.1)

R_2 (cont'd) detail that is not directly related to the Operability of the instrumentation and will be relocated to a licensee controlled document. The Allowable Value is the required limitation for the parameter and this value will be inserted in the table. Any change to the trip setpoints will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_3 This change proposes to relocate specific information about the Functions (e.g., other Functions required to initiate the system, the role of the Function in initiating the system, etc.). This information will be relocated to the Bases of the proposed Technical Specifications. Any changes to this requirement will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_4 This change relocates the requirements for the Trip System bus power monitors, the core spray sparger differential pressure monitor, the LPCI Cross Connect Position Indication, and the Surveillance requirements for the ADS Relief Valves Bellows pressure switches to a licensee controlled document. These monitors do not necessarily relate directly to the respective system Operability. In general, the BWR Standard Technical Specifications support Operability of a system or component. Control of the availability of, and necessary compensatory activities if not available, for indications, monitoring instruments, and alarms are addressed by plant operational procedures and policies. Therefore, this instrumentation, along with the supporting surveillances and actions are relocated. Any changes to these requirements will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_5 This change proposes to relocate specifics about the instruments (what they consist of, etc.) to the procedures/bases. Any changes to these requirements will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_6 This change proposes that the surveillance for the area cooling for safeguards systems (CTS Table 4.2.B, Item 8) be relocated to plant procedures. The requirement for testing the compartment coolers initiation was relocated to plant procedures. Details on testing some support systems have been relocated to licensee controlled documents. Relocating requirements for the compartment coolers does not preclude them from being maintained Operable. They are required to be Operable in order for the HPCI, RCIC, LPCI and CS systems to be Operable and as a result are adequately addressed by the definition of Operability. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, R_4, R_5, R_6, and R_7 Labeled Comments/Discussions for ITS 3.3.5.1) - continued

R_7 This instrument Function is being relocated to plant specific controls. This instrument has no impact on the LPCI System. The purpose of this instrument is to preclude inadvertent actuation of containment and suppression pool sprays during a LOCA. If a LOCA signal is present, the containment and suppression pool spray valves cannot be opened unless the reactor vessel water level is above the 2/3 core height level (to preclude diversion of LPCI when it is needed for core flooding) and the drywell pressure is ≥ 1.0 psig and ≤ 2.0 psig (indicative of a valid need for operating drywell and suppression pool sprays). If the instrument is inoperable such that it trips too soon or too late (or not at all), the LPCI System is not impacted.

If the instrument trips too soon, the reactor vessel water level 2/3 core height Function still ensures that flow is not diverted away from core flooding. In fact, the major contributor to potential flow diversion is suppression pool cooling, and its valves are only precluded from opening by the 2/3 core height instrument. The flow diverted by the drywell and suppression pool sprays is a small fraction of that diverted by suppression pool cooling. Thus, Operability of LPCI is not impacted. While tripping of the instrument allows one of the permissives for opening drywell and suppression pool spray valves to be met, inadvertent operation does not result, since manual actions must still be taken to open the valves if the other permissive (2/3 core height) is also met. In addition, if a LOCA signal is not present, this instrument does not preclude operation of the drywell and suppression pool spray valves. Therefore, inadvertent operation of drywell spray has been analyzed at PBAPS and does not result in containment failure due to operation of the reactor building-to-suppression chamber and the suppression chamber-to-drywell vacuum breakers. These vacuum breakers are controlled by Technical Specifications (current and proposed). Therefore, Operability of the Suppression Pool Spray System is not impacted.

If the instrument trips too late or not at all, then no flow can be diverted by the drywell and suppression pool sprays; thus LPCI is not affected. The only Technical Specification system affected in this case is the Suppression Pool Spray System. A failure of the instrument to function would preclude the suppression pool spray valves from being opened from the control room. However, this system is a manually controlled system that is not needed for a

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, R_4, R_5, R_6, and R_7 Labeled Comments/Discussions for ITS 3.3.5.1)

R_7 (cont'd) minimum of 10 minutes following a DBA LOCA, and the valve could still be opened locally at the valve operator. In addition, the instrument could be overridden to allow operation from the control room. Therefore, failure of this instrument may not even result in the Suppression Pool Spray System being inoperable.

Since this instrument does not relate to LPCI Operability, and the Suppression Pool Spray System is a manually actuated system, this instrument Function is being relocated to plant specific controls. Any change to this instrument function will be controlled by the provisions of 10 CFR 50.59.

(R_1, R_2, R_3, and R_4 Labeled Comments/Discussions for ITS 3.3.5.2)

R_1 The change will relocate items which are procedural in nature (e.g., conversions, specific instructions, etc.) to procedures. These items will be retained and will require a 10 CFR 50.59 review in order to be changed. This change is consistent with NUREG-1433.

R_2 This change proposes to relocate the current "Trip Level Setting" column in current Technical Specifications Table 3.2.B and replace it with an "Allowable Value" column in the proposed Technical Specifications Table 3.3.5.2-1. Trip setpoints are an operational detail that is not directly related to the Operability of the instrumentation and will be relocated to a licensee controlled document. The Allowable Value is the required limitation for the parameter and this value will be inserted in the table. Any change to the trip setpoints will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_3 This change proposes to relocate specifics about the instruments (what they consist of, etc.) to the procedures/Bases. Any changes to these requirements will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_4 This change relocates the requirements for the Trip System bus power monitor to a licensee controlled document. This monitor does not necessarily relate directly to the respective system Operability. In general, the BWR Standard Technical Specifications support Operability of a system or component. Control of the availability

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, and R_4 Labeled Comments/Discussions for ITS 3.3.5.2)

R_4 (cont'd) of, and necessary compensatory activities if not available, for indications, monitoring instruments, and alarms are addressed by plant operational procedures and policies. Therefore, this instrumentation, along with the supporting surveillances and actions are relocated. Any changes to these requirements will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

(R_1, R_2, R_3, R_4, R_5, R_6, R_7, and R_8 Labeled Comments/Discussions for ITS 3.3.6.1)

R_1 Existing Specification 3.2.A, Table 3.2.A, Item 2, Reactor High Pressure (Shutdown Cooling Isolation), isolates the Shutdown Cooling System whenever reactor pressure exceeds 75 psig. This trip has a reset function that is controlled by Specification 3.2.B, Table 3.2.B, Reactor Low Pressure. This reset function provides a permissive for inclusion of the LPCI injection valves in the Shutdown Cooling System Isolation if reactor pressure is below the reset setpoint and the shutdown cooling suction valves are open. Specification 3.2.B, Table 3.2.B, Reactor Low Pressure, will be relocated to plant procedures because the permissive from the reset of Reactor High Pressure (Shutdown Cooling Isolation) does not serve a safety function. Inclusion of the LPCI injection valves in the Shutdown Cooling System Isolation requires the shutdown cooling suction valves to be open in addition to the reset of the reactor pressure trip. However, opening the shutdown cooling suction valves also requires the reset of the reactor pressure trip. Failure of the reactor pressure trip to reset will prevent the opening of the shutdown cooling suction valves and eliminate the need for the Shutdown Cooling Isolation Function. Therefore, Specification 3.2.B, Table 3.2.B, Reactor Low Pressure, will be relocated to plant procedures. Any changes to this requirement will require a 10 CFR 50.59 review. Relocation of this requirement is consistent with NUREG-1433.

R_2 This change proposes to relocate the number of instrument channels provided by design column for each Function. This information will be relocated to the Bases of the proposed Technical Specifications. Any changes to this requirement will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, R_4, R_5, R_6, R_7, and R_8 Labeled Comments/Discussions for ITS 3.3.6.1) - continued

R_3 The specific details relating to the design, plant operations, performance of surveillances and maintenance of the PCI Instrumentation are being relocated to the plant controlled procedures. Placing these details in the plant procedures provides assurance they will be maintained. Changes to the plant procedures are controlled so that the information will not be changed without a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_4 Currently, setpoints for HPCI and RCIC isolation on the steam line low pressure function (Table 3.2.B) is specified as "100>p>50 psig." This specification of both the trip and trip reset pressure provides some assurance of the availability of HPCI and RCIC following a trip on steam line low pressure. Specification 3.3.6.1 (Functions 3.c and 4.c) will specify the steam line low pressure trip setpoint. However, the trip reset will be relocated to plant procedures because the trip reset is not assumed in any accident analysis. Placing this requirement in the plant procedures provides assurance it will be maintained. Changes to the plant procedures are controlled so that the information will not be changed without a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_5 This change proposes to relocate the current Trip Level Setting" column in current Technical Specifications Tables 3.2.A, 3.2.B and 3.2.D and replace it with an "Allowable Value" column in the proposed Technical Specifications Table 3.3.6.1-1. Trip setpoints are an operational detail that is not directly related to the Operability of the instrumentation and will be relocated to a licensee controlled document. The Allowable Value is the required limitation for the parameter and this value will be inserted in the table. Any change to the trip setpoints will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_6 Existing Specification 3.2.A (Table 3.2.A, Note 9) contains compensatory actions associated with recovery of a loss of ventilation in the MSL tunnel. These compensatory actions are not needed to satisfy Required Actions for a complete loss of isolation function specified in NUREG-1433 but represent good engineering practice. Therefore, the compensatory actions associated with recovery of a loss of ventilation in the MSL tunnel currently in existing Specification 3.2.A (Table 3.2.A, Note 9) are being relocated to the Bases.

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, R_4, R_5, R_6, R_7, and R_8 Labeled Comments/Discussions for ITS 3.3.6.1) - continued

R_7 System operational details (when not to place in trip) have been relocated to the Bases and procedures. These details are unnecessary in the LCO and can be adequately controlled in the Bases and procedures. Changes to the Bases will be controlled by the provisions of the Bases Control Process in Chapter 5 of the Technical Specifications. Changes to procedures will be controlled by the provisions of 10 CFR 50.59.

R_8 Existing Specification 3.2.A, Table 3.2.A, Item 11, Reactor Cleanup System High Temperature isolates the Reactor Water Cleanup (RWCU) System non-regenerative heat exchanger to protect the ion exchanger resin from damage due to high temperatures. Credit for this instrument is not assumed in any transient or accident analysis in the UFSAR, since this isolation is for ion exchanger resin protection only. As a result, the existing Technical Specification requirements for this function (including actions and surveillances) will be relocated to plant procedures. Any changes to these requirements will require a 10 CFR 50.59 review. Therefore, placing these requirements in plant procedures provides assurance they will be adequately maintained.

(R_1, R_2, and R_3 Labeled Comments/Discussions for ITS 3.3.6.2)

R_1 This change proposes to relocate the current "Trip Level Setting" column in current Technical Specifications Table 3.2.B and replace it with an "Allowable Value" column in the proposed Technical Specifications Table 3.3.6.2-1. Trip setpoints are an operational detail that is not directly related to the Operability of the instrumentation and will be relocated to a licensee controlled document. The Allowable Value is the required limitation for the parameter and this value will be inserted in the table. Any change to the trip setpoints will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_2 The change will relocate details relating to design and operations and items that are procedural in nature (e.g., specific instructions, etc.) to procedures. These details will be retained and will require a 10 CFR 50.59 review in order to be changed. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, and R_3 Labeled Comments/Discussions for ITS 3.3.6.2) - continued

R_3 System operational details (when not to place in trip) have been relocated to the Bases and procedures. These details are unnecessary in the LCO and can be adequately controlled in the Bases and procedures. Changes to the Bases will be controlled by the provisions of the Bases Control Process in Chapter 5 of the Technical Specifications. Changes to procedures will be controlled by the provisions of 10 CFR 50.59.

(R_1, R_2, R_3, and R_4 Labeled Comments/Discussions for ITS 3.3.7.1)

R_1 This change proposes to relocate the current "Trip Level Setting" column in current Technical Specifications Table 3.2.D and replace it with an "Allowable Value" column in proposed Technical Specification 3.3.7.1. Trip setpoints are an operational detail that is not directly related to the Operability of the instrumentation and will be relocated to a licensee controlled document.

R_2 This change proposes to relocate specific details about the instrument (number of channels provided by design, etc.) to the Bases. Placing these details in the Bases provides assurance they will be maintained. Changes to the Bases will be controlled using the Bases Control Process in Chapters 5 of the Technical Specifications.

R_3 The requirements for trip functions for the MCREV initiation instrumentation not associated with the Control Room Air Intake Radiation—High channels have been relocated to a licensee controlled document. These trip functions are not credited in the safety analysis for initiating the MCREV System. In addition, the functions to be relocated have no impact on the Control Room Air Intake Radiation—High channel Operability. Changes to these requirements will be controlled using 10 CFR 50.59. This change is consistent with NUREG-1433.

R_4 The proposed change will relocate items which are procedural in nature (e.g., conversions, specific instructions, etc.) to procedures. These items will be retained and will require a 10 CFR 50.59 review in order to be changed. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS (continued)
(R_1, R_2, R_3, and R_4 Labeled Comments/Discussions for ITS 3.3.8.1)

R_1 The change will relocate items which are procedural in nature (e.g., conversions, specific instructions, etc.) to procedures. These items will be retained and will require a 10 CFR 50.59 review in order to be changed. This change is consistent with NUREG-1433.

R_2 This change proposes to relocate the current "Trip Level Setting" column in current Technical Specifications Table 3.2.B and replace it with an "Allowable Value" column in the proposed Technical Specifications Table 3.3.8.1-1. Trip setpoints are an operational detail that is not directly related to the Operability of the instrumentation and will be relocated to a licensee controlled document. The Allowable Value is the required limitation for the parameter and this value will be inserted in the table. Any change to the trip setpoints will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_3 This change proposes to relocate specifics about the instruments (the specific function(s) they perform, etc.) to the UFSAR/Bases. Any changes to these requirements will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_4 This change proposes to relocate the Trip Level Setting for the 4 kV Emergency Bus Undervoltage Relay. Trip setpoints are an optional detail that is not directly related to the Operability of the instrumentation and will be relocated to a licensee controlled document. This change is consistent with NUREG-1433.

(R_1 and R_2 Labeled Comment/Discussion for ITS 3.3.8.2)

R_1 The details of what constitutes a trip train (an electric power monitoring assembly) have been relocated to the Bases. Placing these details in the Bases provides assurance that they will be maintained. Changes to the Bases will be controlled using the Bases Control Process in Chapter 5.0 of the Technical Specifications.

R_2 This change proposes to relocate the current maximum setpoint for the undervoltage and underfrequency relays, and the minimum setpoint for the overvoltage relay and underfrequency time delay relay in current Technical Specifications 4.1.D.1 and 4.1.D.2. These setpoints are an operational detail that is not directly related to the Operability of the instrumentation and will be relocated to a

TECHNICAL CHANGES - RELOCATIONS
(R_1 and R_2 Labeled Comment/Discussion for ITS 3.3.8.2)

R_2 (cont'd) licensee controlled document. The Allocable Value is the required limitation for the parameter and this value will be maintained in the applicable SRs. Any change to the relocated setpoints will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

(R_1 Labeled Comment/Discussion for CTS 3/4.15)

R_1 This proposed change will relocate CTS 3/4.15, "Seismic Monitoring Instrumentation," and associated Bases to a licensee controlled document. This Specification provides the requirements for the seismic monitors and recorders. The seismic monitors and recorders function to determine the magnitude of a seismic event. These instruments do not perform any automatic action. They are used to measure the magnitude of a seismic event to ensure the design margins for plant equipment and structures have not been violated. These instruments do not meet any criteria in the NRC Policy Statement. Therefore, per the NRC Policy Statement, this Specification can be relocated out of Technical Specifications. Any changes to these requirements will require a 10 CFR 50.59 evaluation. The change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

    This proposed change relocates requirements from the Technical Specifications to a licensee controlled document. The licensee controlled document containing the relocated requirements will be maintained using the provisions of 10 CFR 50.59 and is subject to the change control process in the Administrative Controls Section of the Technical Specifications. Since any changes to a licensee controlled document will be evaluated per 10 CFR 50.59, no increase (significant or insignificant) in the probability or consequences of an accident previously evaluated will be allowed. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - RELOCATIONS (continued)

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This change relocates requirements to a licensee controlled document. This change will not alter the plant configuration (no new or different type of equipment will be installed) or make changes in methods governing normal plant operation. This change will not impose different requirements and adequate control of information will be maintained. This change will not alter assumptions made in the safety analysis and licensing basis. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change relocates requirements from the Technical Specifications to a licensee controlled document. This change will not reduce a margin of safety since it has no impact on any safety analysis assumptions. In addition, the requirements to be transposed from the Technical Specifications to the licensee controlled document are the same as the existing Technical Specifications. Since any future changes to this licensee controlled document will be evaluated per the requirements of 10 CFR 50.59, no reduction (significant or insignificant) in a margin of safety will be allowed. Therefore, this change will not involve a significant reduction in a margin of safety.

   The existing requirement for NRC review and approval of revisions, in accordance with 10 CFR 50.90, to these details and requirements proposed for relocation, does not have a specific margin of safety upon which to evaluate. However, since the proposed change is consistent with the BWR Standard Technical Specifications (NUREG-1433 approved by the NRC Staff) and the change controls for proposed relocated details and requirements provide an equivalent level of regulatory authority, revising the Technical Specifications to reflect the approved level of detail and requirements ensures no reduction in the margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion for ITS 3.3.1.1)

The proposed change adds a Note to the 184 day and 18 month Channel Calibration Surveillance Requirements excluding the neutron detectors from these Surveillances. The Channel Calibration is a complete check of the instrument loop and the sensor. The test verifies that the channel responds to the measured parameter within the necessary range and accuracy. The neutron detectors are excluded from the Channel Calibrations because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performance of the 7 day calorimetric calibration (SR 3.3.1.1.2) and the 1000 MWD/T LPRM calibration against the TIPs (SR 3.3.1.1.8). This change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change excludes neutron detectors from Channel Calibration Surveillance Requirements. The probability of an accident is not increased by these changes because the proposed change does not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, or modified. The consequences of an accident will not be increased because the change will not affect the ability of the Local Power Range Monitor strings or the Average Power Range Monitors to detect and respond to core conditions. The neutron detectors are excluded from the Channel Calibrations because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performance of the 7 day calorimetric calibration (SR 3.3.1.1.2) and the 1000 MWD/T LPRM calibration against the TIPs (SR 3.3.1.1.8). Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L, Labeled Comment/Discussion for ITS 3.3.1.1) - continued

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This proposed change will not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, or inspected. The proposed change still provides adequate assurance the neutron detectors remain capable of performing their function. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   The proposed change excludes neutron detectors from Channel Calibration Surveillance Requirements. The proposed change does not involve a significant reduction in a margin of safety because the change will not affect the ability of the Local Power Range Monitor strings or the Average Power Range Monitors to detect and respond to core conditions. The neutron detectors are excluded from the Channel Calibrations because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performance of the 7 day calorimetric calibration (SR 3.3.1.1.2) and the 1000 MWD/T LPRM calibration against the TIPs (SR 3.3.1.1.8). As a result, the change does not affect the current analysis assumptions and adequate assurance is provided that the neutron detectors will be maintained Operable. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_2 Labeled Comment/Discussion for ITS 3.3.1.1)

This change proposes to relax the following requirement for the specified Functions.

- The Mode Switch in Shutdown, Manual Scram, High Flux IRM, IRM Inoperable, and High Scram Discharge Volume Water Level (this Function is currently modified by a note which states it is permissible to bypass this Function when the mode switch is in refuel or shutdown; this will be addressed in M_1 Discussion of Changes for ITS 3.3.1.1) Functions will be Operable with the mode switch in refuel, the reactor subcritical, and the water temperature less than 212°F.

The proposed change will require the above Functions to be Operable only when in MODE 5 (Refuel) with any control rod withdrawn from a core cell containing one or more fuel assemblies. This change does not impact the safety of the plant or any of the safety analysis assumptions. The design function of the RPS Functions are to shutdown the reactor when required by initiating a reactor scram. This is only possible when control rods are withdrawn. Control rods withdrawn from a core cell containing no fuel assemblies do not affect the reactivity of the core. With all the rods inserted the Shutdown Margin Requirements (LCO 3.1.1) and the required one-rod-out interlock (LCO 3.9.2) ensure no event will occur. The Actions for inoperable equipment in Mode 5 are also revised to be consistent with the proposed Applicability. Since all control rods are required to be fully inserted during fuel movement (LCO 3.9.3), the proposed applicable conditions cannot be entered while moving fuel. The only possible core alteration is control rod withdrawal which is adequately addressed by the proposed actions. This change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change will require the associated RPS Functions (Mode Switch in shutdown, Manual Scram, High Flux IRM, IRM Inoperable, and High Scram Discharge Volume Water Level) to be Operable only when in Mode 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies. The proposed change does not affect the probability of an accident. These Functions are not assumed in the accident analysis when in Mode 5 with all control rods inserted in core cells containing one or

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_2 Labeled Comment/Discussion for ITS 3.3.1.1)

1. (continued)

more fuel assemblies. The design function of these RPS Functions is to shutdown the reactor when required by initiating a reactor scram. This is only possible when control rods are withdrawn. With all the control rods inserted the shutdown margin and the required one-rod-out interlock ensure no event will occur. This change will continue to ensure the RPS Instrumentation is maintained consistent with analysis assumptions. The consequences of an accident are not affected by this change. This change will not alter assumptions relative to the mitigation of an accident or transient event. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This change will require the associated RPS Functions to be Operable only when in Mode 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies. The proposed change to the Applicability will not create the possibility of an accident. This change will not physically alter the plant (no new or different type of equipment will be installed). The changes in methods governing normal plant operation are consistent with the current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change will require the associated RPS Functions to be Operable only when in Mode 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies. The margin of safety will not be affected by this change. The design function of the RPS Functions is to shutdown the reactor by initiating a reactor scram. This is only possible when control rods are withdrawn. Control rods withdrawn from a core cell containing no fuel assemblies do not affect the reactivity of the core. With all the rods inserted the Shutdown Margin requirements and the required one-rod-out interlock ensure no event will occur. The safety analysis assumptions will still be maintained, thus no question of safety exists. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_3 Labeled Comment/Discussion for ITS 3.3.1.1)

The Frequency for the Turbine First Stage Pressure Permissive Channel Calibration is being decreased from 6 months to 24 months. PBAPS operating history has shown this instrument to be continually reliable over a 24 month period. Therefore, it is acceptable to decrease the Frequency of this Surveillance. This change is also essentially consistent with NUREG-1433, which requires the SR to be performed on a refueling outage basis.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change relaxes the Surveillance Frequency for the Turbine First Stage Pressure (TFSP) Permissive Channel Calibration (existing Surveillance in Table 4.1.2) from 6 months to 24 months. The proposed change does not affect the probability of an accident. The Frequency for the TFSP Permissive Channel Calibration is not assumed to be an initiator of any analyzed event. The proposed change still provides assurance TFSP Permissive Instrumentation Operability is maintained consistent with analysis assumptions. Operating history has shown that TFSP Permissive Instrumentation would be continually reliable during the extended Surveillance interval. The consequences of an accident are not affected by relaxing the frequency of the Surveillance since the consequences of a design basis accident with TFSP Permissive inoperable over the 6 month interval (due to an undetected failure) are the same as the consequences of a design basis accident with TFSP Permissive inoperable for the additional 18 month period. Additionally, the most common outcome of the performance of a Surveillance is the successful demonstration that the acceptance criteria are satisfied. This change will not alter assumptions relative to the mitigation of an accident or transient event. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_3 Labeled Comment/Discussion for ITS 3.3.1.1) - continued

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This change relaxes the Surveillance Frequency for the TFSP Permissive Channel Calibration. The proposed change to the Frequency will not create the possibility of an accident. This change will not physically alter the plant (no new or different type of equipment will be installed). The changes in methods governing normal plant operation are consistent with current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change relaxes the Surveillance Frequency for the TFSP Permissive Channel Calibration. The proposed change to the Frequency is acceptable since the proposed Frequency is adequate for ensuring the TFSP Permissive Instrumentation is maintained Operable. In addition, operating history has shown that TFSP Permissive Instrumentation would be continually reliable during the extended Surveillance interval. Therefore, the margin of safety is not significantly reduced because the proposed changes to the Surveillance Frequency will continue to provide the necessary assurance that the TFSP Permissive Instrumentation will perform as required. Also, this change is considered acceptable since the most common outcome of the performance of a Surveillance is the successful demonstration that the acceptance criteria are satisfied. The safety analysis assumptions will still be maintained, thus, no question of safety exists. Therefore, this change will not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_4 Labeled Comment/Discussion for ITS 3.3.1.1)

The proposed change will require only the control rods in core cells containing one or more fuel assemblies to be inserted if the applicable Action A, B, or C cannot be performed within the required Completion Times. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core cells and are, therefore, not required to be inserted. The removal of the four fuel bundles surrounding a control rod very significantly reduces the reactivity worth of the associated control rod to the point where removal of that rod no longer has the potential to cause a reactivity excursion. This fact is recognized in the design of the control rod velocity limiter which precludes removal of a rod prior to removal of the four adjacent bundles. This is also reflected on the proposed definition of Core Alterations. This change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change will require only the control rods in core cells containing one or more fuel assemblies to be inserted if the a Reactor Protection System (RPS) Function is inoperable and RPS trip capability cannot be restored in the specified Completion Time. The probability of an accident is not increased by this change because the insertion of control rods in response to the inability to satisfy Required Actions is not considered the initiator of any analyzed event. Additionally, this change will not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, tested, or inspected. The consequences of an accident will not be increased because a core cell without any fuel bundles but with the associated control rod fully withdrawn contributes less reactivity to the core than a core cell with one or more fuel bundles and a fully inserted control rod. As a result, the absence of all four fuel bundles satisfies the safety objective of fully inserting a control rod. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_4 Labeled Comment/Discussion for ITS 3.3.1.1) - continued

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This proposed change will not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, tested, or inspected. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   The proposed change will require only the control rods in core cells containing one or more fuel assemblies to be inserted if the a Reactor Protection System (RPS) Function is inoperable and RPS trip capability cannot be restored in the specified Completion Time. The proposed change does not involve a significant reduction in a margin of safety because a core cell without any fuel bundles but with the associated control rod fully withdrawn contributes less reactivity to the core than a core cell with one or more fuel bundles and a fully inserted control rod. As a result, the absence of all four fuel bundles satisfies the safety objective of fully inserting a control rod. As a result, the change does not affect the current analysis assumptions. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_5 Labeled Comment/Discussion For ITS 3.3.1.1)

Not used.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_6 Labeled Comment/Discussion for ITS 3.3.1.1)

The proposed change will relax the current Actions for the Condenser Vacuum Low Function if the channel or trip system cannot be placed in trip within the required Completion Time. The current Actions require the rods to be inserted or to reduce turbine load and close the main steam line isolation valves within 6 hours. The proposed change will require the plant to be brought to MODE 2 within 6 hours. This would put the plant in a Mode which is outside the Mode of Applicability. The Condenser Low Vacuum Function ensures the integrity of the main turbine condenser by decreasing the severity of the transient on the condenser. This Function is only required in Mode 1 because in Mode 2 the heat generation rate is low enough so that the other diverse RPS functions provide sufficient protection. Therefore, by placing the plant in Mode 2, the plant is in a Mode where protection from this Function is not required. Thus, carrying out the current Actions is not required to put the plant in a safe condition. This change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change will relax the Required Actions whenever a channel or trip system for the Condenser Low Vacuum Function of RPS is inoperable and cannot be placed in trip within the required Completion Times. The current Actions require the rods to be inserted or turbine load reduced and the MSIVs closed within 6 hours. The proposed change will require the plant to be brought to MODE 2 within 6 hours. The probability of an accident is not increased by this change because: the proposed Completion Time of 6 hours to place the reactor outside the Mode of Applicability is equivalent to the Completion Time associated with one of the alternatives currently allowed; the change does not involve changes to any plant hardware or plant operating procedures; and, the change in the proposed Required Actions does not involve activities assumed to be initiators of any analyzed event. The consequences of an accident will not be increased because: the Function capability is maintained by redundant channels; the proposed Required Actions place the reactor outside the Mode of Applicability of the Function that is inoperable in an equivalent time period as one of the current options; the consequences of an accident

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_6 Labeled Comment/Discussion for ITS 3.3.1.1)

1. (continued)

with an inoperable and untripped Low Condenser Vacuum (RPS) channel or trip system before the Required Actions are completed are not changed; and, the change will not allow continuous operation with plant conditions such that a single failure will preclude the affected RPS function from being performed. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

This proposed change will not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, tested, or inspected. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

The proposed change does not result in a significant reduction in the margin of safety because: placing the reactor in Mode 2 versus MSIV isolation or reactor shutdown is sufficient to reduce the heat rate sufficiently so that other diverse RPS functions provide sufficient protection; the proposed Completion Time of 6 hours to place the reactor outside the Mode of Applicability is equivalent to the Completion Time associated with one of the alternatives currently allowed; and, the Function capability is maintained by redundant channels. As a result, the change does not affect the current analysis assumptions. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_7 Labeled Comment/Discussion for ITS 3.3.1.1)

The proposed change will relax the current Actions for the Main Steam Line Isolation Valve Closure Function if the channel or trip system cannot be placed in trip within the required Completion Time. The current Actions require the rods to be inserted immediately. The proposed change will require the plant to be brought to Mode 2 within 6 hours. This would put the plant in a Mode which is outside the Mode of Applicability. The Main Steam Line Isolation Valve Closure Function ensures the reactor is shutdown in the event of main steam line isolation valve closure which reduces the amount of heat generation by the reactor. This Function, along with the ECCS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. In Mode 2, this Function is not required because the heat generation rate is low enough that the other diverse RPS functions provide sufficient protection. Therefore, by placing the plant in Mode 2, the plant is in a Mode where protection from this Function is not required. Thus, carrying out the current Actions is not required to put the plant in a safe condition. This change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change will relax the current Required Actions for the Main Steam Line Isolation Valve Closure Function whenever an inoperable channel or trip system cannot be placed in trip within the required Completion Time. The current Actions require the rods to be inserted immediately. The proposed change will require the plant to be brought to MODE 2 within 6 hours. The probability of an accident is not increased by this change because: the change does not involve changes to any plant hardware or plant operating procedures; and, the change in the proposed Required Actions does not involve activities assumed to be initiators of any analyzed event. The consequences of an accident will not be increased because: placing the reactor in Mode 2 versus inserting all control rods is sufficient to ensure that the heat generation rate is low enough that the other diverse RPS functions and Emergency Core Cooling Systems provide sufficient protection; the MSIV Function capability is maintained by redundant channels; the change will not allow continuous operation with plant conditions such that a single failure will preclude the MSIV isolation function from being performed; and, the consequences of an

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_7 Labeled Comment/Discussion for ITS 3.3.1.1)

1. (continued)

accident with an inoperable channel or trip system in MSIV Closure Function before the Required Actions are completed are not changed. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

This proposed change will not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, tested, or inspected. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

The proposed change does not result in a significant reduction in the margin of safety because: the change does not involve changes to any plant hardware or plant operating procedures; the change in the proposed Required Actions does not involve activities assumed to be initiators of any analyzed event; placing the reactor in Mode 2 versus inserting all control rods is sufficient to ensure that the heat generation rate is low enough that the other diverse RPS functions and Emergency Core Cooling Systems provide sufficient protection; the MSIV Function capability is maintained by redundant channels; and, the change will not allow continuous operation with plant conditions such that a single failure will preclude the MSIV isolation function from being performed. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_8 Labeled Comment/Discussion for ITS 3.3.1.1)

This change proposes to add a Note to the 7 day Channel Functional Test Surveillance Requirement (SR 3.3.1.1.3) and the 184 day Channel Calibration (SR 3.3.1.1.11). The Note will allow the plant to enter Mode 2 from Mode 1 without performing the required Surveillance. The surveillance, however, must be performed within 12 hours after entering Mode 2. This is allowed because the testing of the Mode 2 required IRM and APRM Functions cannot be performed in Mode 1 without utilizing jumpers, lifted leads, or movable links. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the Surveillance Requirement.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change proposes to add a Note to the 7 day Channel Functional Test Surveillance Requirement and the 24 month Channel Calibration. The Notes will allow the plant to enter Mode 2 from Mode 1 without performing the 7 day Channel Functional Test or the 24 month Channel Calibration. The Surveillance, however, must be performed within 12 hours after entering Mode 2. The proposed change does not increase the probability of an accident. The Surveillance Frequency for the Channel Functional Test and Channel Calibration is not assumed to be an initiator of any analyzed event. The proposed change still provides assurance the associated RPS Functions are maintained consistent with analysis assumptions. The Notes allow time once in Mode 2 to perform the Surveillances because the associated IRMs and APRM Functions cannot be performed in Mode 1 without utilizing jumpers, lifted leads, or movable links. The 12 hour time limit is based on operating experience and in consideration of providing a reasonable time in which to complete the Surveillance Requirement. The proposed change provides confirmation of the Operability of the associated RPS Functions at the earliest opportunity when these Functions are required. In addition, the most common outcome of the performance of a Surveillance is the successful demonstration that the acceptance criteria are satisfied. As a result, the consequences of an accident are not affected by this change. This change will not alter assumptions relative to the mitigation of an accident or transient event. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_8 Labeled Comment/Discussion for ITS 3.3.1.1) - continued

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The proposed change will not create the possibility of an accident. This change will not physically alter the plant (no new or different type of equipment will be installed). The changes in methods governing normal plant operation are consistent with the current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change proposes to add a Note to the 7 day Channel Functional Test Surveillance Requirement and the 24 month Channel Calibration. The Notes will allow the plant to enter Mode 2 from Mode 1 without performing the 7 day Channel Functional Test or the 24 month Channel Calibration. The Surveillance, however, must be performed within 12 hours after entering Mode 2. The margin of safety is not significantly reduced because the proposed change to the Surveillance Frequency will continue to provide the necessary assurance of Operability of the associated RPS Functions at the earliest opportunity. These changes effectively extend the initial performance of the Surveillance Requirement by 12 hours. This is considered acceptable since the most common outcome of the performance of a Surveillance is the successful demonstration that the acceptance criteria are satisfied. In addition, these changes provide the benefit of allowing the Surveillance to be postponed until plant conditions exist where the Surveillance can be performed without utilizing jumpers, lifted leads, or movable links. The safety analysis assumptions will still be maintained, thus no question of safety exists. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_9 Labeled Comment/Discussion for ITS 3.3.1.1)

This change decreases the Surveillance Frequency for the performance of the APRM heat balance calibration from twice per week to once per week. This Surveillance Requirement ensures that the APRMs are accurately indicating the true core average power which is affected by LPRM sensitivity. The 7 day Surveillance frequency is acceptable, based on operating experience and the fact that only minor changes in LPRM sensitivity occur during this time frame. Also the most common outcome of the performance of a surveillance is the successful demonstration that the acceptance criteria are satisfied. This change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change relaxes the Surveillance Frequency for the performance of the APRM heat balance calibration from twice per week to once per week. The proposed change does not affect the probability of an accident. The Frequency of the APRM heat balance is not assumed to be an initiator of any analyzed event. The proposed change still provides assurance the APRMs are maintained consistent with analysis assumptions. The consequences of an accident are not affected by decreasing the frequency of the Surveillance to verify the APRM heat balance since the most common outcome of the performance of a surveillance is the successful demonstration that the acceptance criteria are satisfied. This change will not alter assumptions relative to the mitigation of an accident or transient event. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This change relaxes the Surveillance Frequency for performance of the APRM heat balance calibration from twice per week to once per week. The proposed changes to the Frequency will not create the possibility of an accident. This change will not physically alter the plant (no new or

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_9 Labeled Comment/Discussion for ITS 3.3.1.1)

2. (continued)

different type of equipment will be installed). The changes in methods governing normal plant operation are consistent with the current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

This change relaxes the Surveillance Frequency for the performance of the APRM heat balance calibration from twice per week to once per week. The increased Surveillance interval is acceptable since the once per week Frequency has been shown, based on industry operating experience, to be adequate for maintaining the APRM heat balance. Therefore, the margin of safety is not significantly reduced because the proposed changes to the Surveillance Frequency will continue to provide the necessary assurance that the APRM heat balance is being maintained within limits. Also, this change is considered acceptable since the most common outcome of the performance of a Surveillance is the successful demonstration that the acceptance criteria are satisfied. The safety analysis assumptions will still be maintained, thus no question of safety exists. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_{10} Labeled Comment/Discussion for ITS 3.3.1.1)

This change adds a note to the APRM heat balance calibration (SR 3.3.1.1.2) which states the Surveillance is not required to be met until 12 hours after Thermal Power ≥ 25% RTP. This is allowed because it is difficult to accurately determine core Thermal Power from 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). This change is consistent with NUREG-1433. The 12 hour time limit for performing the surveillance is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change does not involve a hardware change. The APRM RPS instrumentation is not assumed in the initiation of any analyzed event. The role of this instrumentation is in mitigating and, thereby, limiting the consequences of analyzed events. The proposed change effectively extends the initial Surveillance Frequency until 12 hours after Thermal Power is ≥ 25% RTP. This allows time after the appropriate conditions are established to perform the Surveillance. The Surveillance is not required to be performed below 25% RTP because it is difficult to accurately determine core Thermal Power from a heat balance at these low power levels. In addition, at low power levels, a high degree of accuracy between the APRM indication and actual core Thermal Power is unnecessary due to the large inherent margin to the thermal limits at these power levels. As a result, the consequences of an accident are not affected by this change. This change will not alter assumptions relative to the mitigation of an accident or transient event. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This change will not alter the plant (no new or different type of equipment will be installed). The changes in methods governing normal plant operation are consistent with current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_{10} Labeled Comment/Discussion for ITS 3.3.1.1) - continued

3. Does this change involve a significant reduction in a margin of safety?

The margin of safety is not reduced by this change since the proposed change to the Surveillance Frequency provides the necessary assurance that the APRM instrumentation has been accurately calibrated at the earliest opportunity. This change extends the initial performance of the Surveillance Requirement to within 12 hours after reaching 25% RTP. This is considered acceptable since below 25% RTP a high degree of accuracy between the APRM indication and actual core Thermal Power is unnecessary due to the large inherent margin to the thermal limits at these power levels. In addition, this change provides the benefit of allowing the Surveillance to be postponed until appropriate plant conditions exist for performing the Surveillance accurately. The safety analysis assumptions will still be maintained, thus no question of safety exists. Therefore, this change does not involve a significant reduction in a margin safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_{11} Labeled Comment/Discussion for ITS 3.3.1.1)

This change proposes to add a Note to the IRM High Flux Channel Calibration which allows the Surveillance to only be required to be met during entry into MODE 2 from MODE 1. Currently the Surveillance is required to be met throughout the controlled shutdown. This change only requires the surveillance to be met during the transition from Mode 2 to Mode 1. After this requirement has been met then maintaining overlap is not required (APRMs may be reading downscale once in MODE 2). This change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change does not result in any hardware changes. The APRM and IRM RPS instrumentation is not assumed to be an initiator of any analyzed event. This instrumentation mitigates and thereby limits the consequences of analyzed events. The proposed change adds a Note to the Surveillance for IRM and APRM overlap to only require the Surveillance to be met during entry into Mode 2 from Mode 1. The overlap requirement is only required when transitioning from APRM indication range to IRM indication range. Once this transition has occurred, the overlap requirement is no longer required for Operability of the IRMs. This occurs in Mode 2 since APRMs may be reading downscale in Mode 2. As such, the proposed change continues to ensure that the overlap requirements are met during the required conditions and that the APRM and IRM indication is reading appropriately. As a result, the consequences of an accident are not affected by this change. This change will not alter assumptions relative to the mitigation of an accident or transient event. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The proposed change does not necessitate a physical alteration of the plant (no new or different type of equipment will be installed) or changes in parameters governing normal operation. The proposed change still provides adequate assurance that APRM and IRM overlap is available during the required conditions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_{11} Labeled Comment/Discussion for ITS 3.3.1.1) - continued

3. Does this change involve a significant reduction in a margin of safety?

The proposed change, which adds a Note to the Surveillance for APRM and IRM overlap limiting it to just during entry into Mode 2 from Mode 1, does not involve a reduction in a margin of safety. With the proposed change APRM and IRM overlap will no longer be required to be met after reaching Mode 2. In Mode 2, the APRMs may be reading downscale and the indication has already transitioned to the IRMs. As a result, maintaining overlap is not required since the IRMs in this condition are fully capable of providing the required indication. However, the proposed change will ensure that APRM and IRM overlap is met during the transition from APRM to IRM indication. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_{sv} Labeled Comment/Discussion for ITS 3.3.1.1, 3.3.2.1, 3.3.4.1, 3.3.5.1, 3.3.5.2, 3.3.6.1, 3.3.6.2, and 3.3.7.1)

This change revises the Technical Specification setpoints for proposed Section 3.3 instrumentation to reflect Allowable Values consistent with the philosophy of NUREG-1433. These Allowable Values (to be included in Technical Specifications) and the Trip Setpoints (to be included in plant procedures) have been established consistent with the PECO Energy Instrument Setpoint Methodology or the General Electric (GE) Instrument Setpoint Methodology; the PBAPS Units 2 & 3 specific safety analysis limits as modified by NEDC-32183P, "Power Rerate Safety Analysis Report for Peach Bottom 2 & 3," dated May 1993; and the uncertainties associated with the PBAPS Units 2 & 3 instrumentation. The setpoint evaluation used actual PBAPS physical data and operating practices to ensure the validity of the resulting Allowable Values and Trip Setpoints. Changes resulting from the Power Rerate analyses and the effect on safety analysis limits were previously evaluated in the licensee amendment requests (93-12) for Power Rerate (letter dated June 23, 1993, from G.A. Hunger (PECO Energy) to NRC). All changes to safety analysis limits, applied in the methodologies, were evaluated and confirmed as ensuring safety analysis licensing acceptance limits are maintained. All design limits, applied in the methodologies, were confirmed as ensuring that applicable design requirements of the associated systems are maintained. The methodologies used to derive the Allowable Values and Trip Setpoints are based on combining the uncertainties of the associated channels as documented in letter dated May 2, 1994 from G.A. Hunger (PECO Energy) to NRC responding to the Request for Additional Information Regarding Power Rerate Request dated March 29, 1994 (RAI-2). The methodologies used in the evaluation are consistent with the methodology used for Limerick Units 1 & 2 and documented in NEDC-31336, "General Electric Instrumentation Setpoint Methodology." The NRC approval of NEDC-31336 is documented in a Safety Evaluation Report transmitted by letter from B. Boger (NRC) to D. Roare (GE) dated February 9, 1993. In the methodologies, the Trip Setpoints take into consideration calibration accuracies which were specifically assumed in the PBAPS Unit 2 & 3 setpoint calculations. Plant calibration procedures will ensure the assumptions regarding calibration accuracy are maintained. The proposed Allowable Values and Trip Setpoints have been established from each design or safety analysis limit by accounting for instrument accuracy, calibration and drift uncertainties, as well as process measurement accuracy and primary element accuracy using the PECO Energy Instrument Setpoint Methodology or the GE Instrument Setpoint Methodology. The use of these methodologies for establishing Allowable Values and Trip Setpoints ensures design or safety analysis limits are not exceeded in the event of transients or accidents and accounts for uncertainties and environmental conditions.

<u>TECHNICAL CHANGES - LESS RESTRICTIVE</u>
(L_{av} Labeled Comment/Discussion for ITS 3.3.1.1, 3.3.2.1, 3.3.4.1, 3.3.5.1, 3.3.5.2, 3.3.6.1, 3.3.6.2, and 3.3.7.1) - continued

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change will not result in any hardware changes. The instrumentation included in proposed Section 3.3 of the Technical Specifications is not assumed to be an initiator of any analyzed event. Existing operating margin between plant conditions and actual plant setpoints is not significantly reduced due to this change. As a result, the proposed changes will not result in unnecessary plant transients. The role of the proposed Section 3.3 instrumentation is in mitigating and thereby limiting the consequences of accidents. The Allowable Values and Trip Setpoints have been developed to ensure that the design and safety analysis limits will be satisfied. The methodology used for the development of the Allowable Values and Trip Setpoints ensures the affected instrumentation remains capable of mitigating design basis events as described in the safety analyses and that the results and consequences described in the safety analyses remain bounding. Additionally, the proposed change does not alter the plant's ability to detect and mitigate events. Therefore, this change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated. This is based on the fact that the method and manner of plant operation is unchanged. The use of the proposed Allowable Values and Trip Setpoints does not impact safe operation of Peach Bottom Atomic Power Station Units 2 & 3 in that the safety analysis limits will be satisfied. The proposed Allowable Value and Trip Setpoints involve no system additions or physical modifications to systems in the station. These Allowable Values and Trip Setpoints were developed using a methodology to ensure the affected instrumentation remains capable of mitigating accidents and transients.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_{av} Labeled Comment/Discussion for ITS 3.3.1.1, 3.3.2.1, 3.3.4.1, 3.3.5.1, 3.3.5.2, 3.3.6.1, 3.3.6.2, and 3.3.7.1)

2. (continued)

Plant equipment will not be operated in a manner different from previous operation, except that setpoints will be changed. Since operational methods remain unchanged and the operating parameters have been evaluated to maintain the station within existing design basis criteria, no different type of failure or accident is created.

3. Does this change involve a significant reduction in a margin of safety?

The proposed change does not involve a reduction in a margin of safety. The proposed changes have been developed using a methodology to ensure safety analysis limits are not exceeded. As such, this proposed change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_1 Labeled Comment/Discussion for ITS 3.3.1.2)

Existing Specification 3.3.B.4 does not identify Required Actions if SRM Operability requirements in Mode 2 are not satisfied; therefore, Specification 3.3.B.4 defaults to LCO 3.0.C which requires that the plant be in Hot Shutdown (Mode 3) within 6 hours. Proposed LCO 3.3.1.2 will identify the Required Actions and associated Completion Times if SRM Operability requirements in Mode 2 are not satisfied. Proposed Condition A will allow 4 hours to restore the 3 required SRM channels to Operable as long as at least one SRM is always Operable. Proposed Condition B will require suspension of all control rod withdrawal if there are no Operable SRMs; and, in accordance with Condition A, will allow 4 hours to make the required 3 SRM channels Operable. Proposed Condition C will require that the reactor be in Mode 3 within 12 hours if Required Actions and Completion Times for Condition A or B are not satisfied. Proposed Conditions A, B, and C are less restrictive than the existing specifications for the following reasons: Condition A will allow control rod withdrawal to continue for up to 4 hours with less than the required number of SRMs Operable; Condition A may be exited either by restoration of the required number of SRM channels or by increasing reactor power until the IRMs are above Range 2; Condition B will allow up to 4 hours to attempt to restore the required number of SRM channels before a reactor shutdown must be initiated; and, Conditions A, B and C allow up to 16 hours (4 hours for Conditions A and B and 12 hours for Condition C) before the reactor must be in Mode 3 when SRM Operability requirements are not satisfied (LCO 3.0.C requires that the plant be in Mode 3 within 6 hours). These changes are acceptable because: SRMs are not credited in the analysis of any accident and exist solely to allow operators to monitor changes in power level during startup; at least one SRM will remain Operable during any rod withdrawal; excessive reactivity additions during Mode 2 will be quickly identified and mitigated by the IRMs, IRM rod blocks, and the IRM Range 1 High Flux Trip function; and, reactivity addition accidents from the source range are assumed to begin with flux below the level of source range detector sensitivity and the analysis assumptions are not affected by the operators ability to monitor changes in flux levels. These less restrictive Required Actions are consistent with BWR Standard Technical Specifications, NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion for ITS 3.3.1.2) - continued

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change: will allow rod withdrawal to continue for 4 hours with less than the required number of SRMs as long as at least one SRM is Operable; will allow operation to continue for 4 hours but without rod withdrawal if no SRMs are Operable; allow exiting the previous two conditions if overlap with the IRMs is established; and, will not require the reactor be in Mode 3 until 16 hours after less than the required number of SRM. The probability of an accident is not increased by these changes because: at least one SRM will remain Operable during rod withdrawal and rod withdrawal will not occur if no SRMs are Operable; and, excessive reactivity additions will be quickly identified and mitigated by the IRMs, IRM rod blocks, and the IRM Range 1 High Flux Trip function. The consequences of an accident will not be increased because the SRMs are not credited for the mitigation of any accidents. The APRM Flux scram is credited for mitigating a rod withdrawal or reactivity addition accident with the IRM High Flux trips acting as a backup. Additionally, reactivity addition accidents from the source range are assumed to begin with flux below the level of source range detector sensitivity. A reactivity addition accident initiated during a normal startup would start from a significantly higher flux level than assumed in the reactivity addition accident. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This proposed change will not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, tested, or inspected. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   The proposed change: will allow rod withdrawal to continue for 4 hours with less than the required number of SRMs as long as at least one SRM is Operable; will allow operation to continue for 4 hours but without rod withdrawal if no SRMs are Operable; allow exiting the previous two conditions if overlap with the IRMs is established; and, will not require the reactor be in Mode 3 until 16 hours after less than the required number of SRM. The proposed change does not involve a significant reduction in a margin of safety because: SRMs are not credited in any

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion for ITS 3.3.1.2)

3. (continued)

safety analysis; at least one SRM will remain Operable during rod withdrawal and rod withdrawal will not occur if no SRMs are Operable; and, excessive reactivity additions will be quickly identified and mitigated by the IRMs and IRM rod blocks and Range 1 High Flux Trip. Additionally, the APRM Flux scram and not any SRM function is credited for mitigating a rod withdrawal or reactivity addition accident. As a result, the change does not affect the current analysis assumptions. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_2 Labeled Comment/Discussion for ITS 3.3.1.2)

If a spiral offload or reload pattern is used, the proposed specifications will allow: 1) a reduction in the number of SRM channels required to be Operable during refueling; and, 2) an exemption from the requirements for minimum observable SRM count rate without having to electrically disarm all control rods in cells that contain fuel. Specifically, existing Specification 3.10.B.1 requires two SRMs during Core Alterations. Proposed Specification 3.3.1.2 (Table 3.3.1.2-1 footnote (b)) reduces the number of SRM channels required to be Operable from 2 to 1 "during spiral offload or reload when the fueled region includes only that SRM detector." A reduction in the number of required Operable SRM channels is acceptable when using a spiral pattern for loading or offloading fuel because the use of a spiral pattern provides assurance that the Operable SRM is in the optimum position for monitoring changes in neutron flux levels resulting from the Core Alteration. Additionally, existing Specification 3.10.B.2 permits the SRM count rate to fall below the specified minimum level if all control rods in cells that contain fuel are fully inserted and electrically disarmed. Proposed SR 3.3.1.2.4 relaxes the requirement for a minimum SRM count rate without having to electrically disarm control rods if a spiral unloading pattern is used. Reduced requirements for SRM minimum count rate are acceptable when using a spiral pattern for unloading fuel because the use of a spiral unloading pattern provides assurance that all fuel movement will result in decreasing core total reactivity and that the Operable SRM is in the optimum position for monitoring changes in neutron flux levels. These changes are consistent with BWR Standard Technical Specifications, NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   If a spiral offload or reload pattern is used, the proposed specifications will allow: 1) a reduction in the number of SRM channels required to be Operable during refueling; and, 2) an exemption from the requirements for minimum observable SRM count rate without having to electrically disarm all control rods in cells that contain fuel. The probability of an accident is not increased by relaxed SRM Operability requirements when using a spiral pattern for fuel movements because the use of a spiral pattern provides assurance that the SRM will be in the optimum position for monitoring changes in neutron flux levels resulting from the Core Alteration. Additionally, the requirement for a minimum SRM count rate

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_2 Labeled Comment/Discussion for ITS 3.3.1.2)

1. (continued)

can be relaxed during a spiral offload without electrically disarming control rods because all fuel movement will result in decreasing core total reactivity and the Operable SRM will be in the optimum position for monitoring changes in neutron flux levels. The consequences of an accident will not be increased by these changes because the SRMs are not credited for the mitigation of any accidents. The APRM Flux scram and not any SRM function is credited for mitigating a rod withdrawal or reactivity addition accident. Backup to the APRM Flux scram during excessive reactivity additions is provided by IRM rod blocks and IRM Range 1 High Flux Trip. Additionally, the reactivity addition accidents are assumed to be initiated from below the level of source range detector sensitivity and, therefore, are independent of any changes in the ability to monitor changes in the source range flux level. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

This proposed change will not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, tested, or inspected. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

If a spiral offload or reload pattern is used, the proposed specifications will allow: 1) a reduction in the number of SRM channels required to be Operable during refueling; and, 2) an exemption from the requirements for minimum observable SRM count rate without having to electrically disarm all control rods in cells that contain fuel. The proposed change does not involve a significant reduction in a margin of safety because: SRMs are not credited in any safety analysis; at least one SRM will remain Operable during rod withdrawal; and, the use of a spiral pattern provides assurance that the SRM will be in the optimum position for monitoring changes in neutron flux levels resulting from the Core Alteration. As a result, the change does not affect the current analysis assumptions. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_1 Labeled Comment/Discussion for ITS 3.3.2.1)

Proposed LCO 3.3.2.1, Conditions A and B, will extend the Completion Time for blocking control rod withdrawal if one RBM channel is inoperable from immediately to within 25 hours. Additionally, proposed LCO 3.3.2.1, Condition B, will extend the Completion Time for blocking control rod withdrawal if both RBM channels are inoperable from immediately to within 1 hour. However, the requirement to block control rod withdrawal if a RBM channel is inoperable will exist whenever the RBM function is required to be Operable and not just "during operation with limiting control rod patterns" as is required by existing Specification 3.3.B.5. These proposed changes are to existing Specification 3.3.B.5. which, if one or both Rod Block Monitor (RBM) channels are inoperable when "limiting control rod patterns" exist, requires blocking all control rod withdrawal or adjusting thermal power to a level where the RBM system is not required to be Operable. The proposed increase in the amount of time allowed to block control rod withdrawal if one RBM channel is inoperable is acceptable because the remaining Operable channel is adequate to perform the control rod block function but the change does not allow continued operation in a configuration where a single failure will result in the loss of the control rod block function. The 1 hour Completion Time to block control rod withdrawal if both RBM channels are inoperable is intended to allow the operator time to evaluate and repair any discovered inoperabilities and is acceptable because it strictly limits the amount of time operation may continue with a complete loss of the RBM function while allowing time for restoration or tripping of inoperable channels. This change is consistent with BWR Standard Technical Specifications, NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change will extend the Completion Time for blocking control rod withdrawal if one RBM channel is inoperable from immediately to within 25 hours. Additionally, proposed LCO 3.3.2.1, Condition B, will extend the Completion Time for blocking control rod withdrawal if both RBM channels are inoperable from immediately to within 1 hour. However, the requirement to block control rod withdrawal if a RBM channel is inoperable will exist whenever the RBM function is required to be Operable and not just "during operation with limiting control rod patterns" as is required by existing Specification 3.3.B.5. The probability of an accident is not increased by this change because the RBM is not assumed to be the initiator of any analyzed event. The purpose of the RBM is to limit a rod

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion for ITS 3.3.2.1)

1. (continued)

withdrawal error (RWE) and prevent violation of the Minimum Critical Power Ratio (MCPR) Safety Limit (SL) and the fuel cladding design limit of less than 1% plastic strain. During the 24 hours of operation permitted with one RBM channel inoperable, the remaining Operable channel is adequate to perform the control rod block function. During the 1 hour of operation permitted with both RBM channels inoperable and a complete loss of the RBM function, a rod withdrawal error is unlikely while allowing time for restoration or tripping of inoperable channels. In both cases, continued operation in a configuration such that a single failure will result in the loss of the control rod block function is strictly limited. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

This proposed change will not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, tested, or inspected. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

The proposed change will extend the Completion Time for blocking control rod withdrawal if one RBM channel is inoperable from immediately to within 25 hours. Additionally, proposed LCO 3.3.2.1, Condition B, will extend the Completion Time for blocking control rod withdrawal if both RBM channels are inoperable from immediately to within 1 hour. However, the requirement to block control rod withdrawal if a RBM channel is inoperable will exist whenever the RBM function is required to be Operable and not just "during operation with limiting control rod patterns" as is required by existing Specification 3.3.B.5. This change does not involve a significant reduction in a margin of safety because during the 24 hours of operation permitted with one RBM channel inoperable, the remaining Operable channel is adequate to perform the control rod block function. During the 1 hour of operation permitted with both RBM channels inoperable and a complete loss of the RBM function, a rod withdrawal error is unlikely while allowing time for restoration or tripping of inoperable channels. In both cases, continued operation in a configuration such that

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion for ITS 3.3.2.1)

3. (continued)

a single failure will result in the loss of the control rod block function is strictly limited. As a result, the change does not affect the current analysis assumptions. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_2 Labeled Comment/Discussion for ITS 3.3.2.1)

Existing Specification 4.3.B.3.b.1 requires a Channel Functional Test of the Rod Worth Minimizer (RWM) "prior to the start of control rod withdrawal toward criticality" and "prior to attaining the Rod Worth Minimizer low power setpoint during rod insertion." Proposed Specification 3.3.2.1 will require a Channel Functional Test of the RWM every 92 days in Mode 2 and every 92 days in Mode 1 when Thermal Power is ≤10%. Proposed SR 3.3.2.1.2 will be modified by a Note stating that the Channel Functional Test is not required during a startup until 1 hour after any control rod is withdrawn at ≤ 10% RTP in Mode 2. Proposed SR 3.3.2.1.3 will be modified by a Note stating that the Channel Functional Test is not required during a shutdown until 1 hour after Thermal Power is ≤10% in Mode 2. The addition of these Notes make the proposed requirement for a Channel Functional Test less restrictive because the Surveillance Test is not required until 1 hour after the RWM is required to be Operable. These changes are acceptable for the following reasons: a) the Rod Worth Minimizer does not monitor core thermal conditions but simply enforces preprogrammed rod patterns as a backup intended to prevent reactor operator error in selecting or positioning control rods; b) reliability analysis documented in NEDC-30851-P-A, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," October 1988 determined that the failure frequency curve for this instrumentation is relatively flat in the range of 30 to 124 days and starts a gradual increase after 124 days which means that more frequent testing is unlikely to identify problems; and, c) it is overly conservative to assume that the RWM is not operable when a surveillance is not performed because of its demonstrated reliability as demonstrated by successful completion of most Channel Functional Tests. This change is consistent with BWR Standard Technical Specifications, NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change is less restrictive in two ways. First, the existing specifications require performance of the Channel Functional Tests "prior to" reaching the condition where the RWM is required to be Operable but the proposed Surveillance Tests are "not required until one hour after" reaching the condition where the RWM is required to be Operable. Second, the existing specification requires that the Channel Functional Test be performed on every startup and shutdown but the proposed specifications will require Channel Functional Tests on startups and shutdowns only if

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_2 Labeled Comment/Discussion for ITS 3.3.2.1)

1. (continued)

the test has not been performed in the previous 92 days. The purpose of the RWM is to limit a rod withdrawal error (RWE) and prevent violation of the Minimum Critical Power Ratio (MCPR) Safety Limit (SL) and the fuel cladding design limit of less than 1% plastic strain. The change does not allow continued operation in a configuration such that a single failure will result in the loss of the control rod block function. In addition, the probability of an accident is not increased because: a) the Rod Worth Minimizer does not monitor core thermal conditions but simply enforces preprogrammed rod patterns as a backup intended to prevent reactor operator error in selecting or positioning control rods; b) reliability analysis documented in NEDC-30851-P-A, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," October 1988 determined that the failure frequency curve for this instrumentation is relatively flat in the range of 30 to 124 days and starts a gradual increase after 124 days which means that more frequent testing is unlikely to identify problems; and, c) it is overly conservative to assume that the RWM is not operable when a surveillance is not performed because of its demonstrated reliability as demonstrated by successful completion of most Channel Functional Tests. The consequences of an accident will not be increased because the RWM is intended to prevent exceeding thermal limits and has no function in mitigating the consequences of an accident. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

This proposed change will not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, tested, or inspected. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

The proposed change is less restrictive in two ways. First, the existing specifications require performance of the Channel Functional Tests "prior to" reaching the condition where the RWM is required to be Operable but the proposed Surveillance Tests are "not required until one hour after" reaching the condition where the RWM is required to be Operable. Second,

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_2 Labeled Comment/Discussion for ITS 3.3.2.1)

3. (continued)

the existing specification requires that the Channel Functional Test be performed on every startup and shutdown but the proposed specifications will require Channel Functional Tests on startups and shutdowns only if the test has not been performed in the previous 92 days. The proposed change does not involve a significant reduction in a margin of safety because: a) the Rod Worth Minimizer does not monitor core thermal conditions but simply enforces preprogrammed rod patterns as a backup intended to prevent reactor operator error in selecting or positioning control rods; b) reliability analysis determined that the failure frequency curve for this instrumentation is relatively flat in the range of 30 to 124 days and starts a gradual increase after 124 days which means that frequent testing is unlikely to identify problems; and, c) it is overly conservative to assume that the RWM is not operable when a surveillance is not performed because of its demonstrated reliability as demonstrated by successful completion of most Channel Functional Tests. Therefore, this change will not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_3 Labeled Comment/Discussion for ITS 3.3.2.1)

The proposed change eliminates Specification 4.3.B.5 which requires a Functional Test of the Rod Block Monitor (RBM) "prior to withdrawal of the designated rod(s)" whenever "a limiting control rod pattern exists" and relies completely upon the Functional Test which is required every 92 days. The proposed change is acceptable because: two independent RBM channels will be Operable during any rod withdrawal except for short and infrequent periods when one channel is inoperable; and, deletion of this requirement allows taking credit for routine periodic tests in place of performing unscheduled testing whenever the potential exists that the RBM may be required to function. The Frequency of 92 days for the Channel Functional Test is based upon the reliability analysis in NEDC-30851-P-A, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," October 1988. This reliability study found that the failure frequency curve for this type of instrumentation is relatively flat in the range of 30 to 124 days and starts a gradual increase after 124 days. Based on this finding, performing this testing more frequently than every 92 days does not significantly increase the probability of detecting a random failure of the RBM. This change is consistent with BWR Standard Technical Specifications, NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change eliminates Specification 4.3.B.5 which requires a Functional Test of the Rod Block Monitor (RBM) "prior to withdrawal of the designated rod(s)" whenever "a limiting control rod pattern exists" and relies completely upon the Functional Test which is required every 92 days. The probability of an accident is not increased by this change because: two independent RBM channels will be Operable during any rod withdrawal except for short and infrequent periods when one channel is inoperable; and, deletion of this requirement allows taking credit for routine periodic tests in place of performing unscheduled testing whenever the potential exists that the RBM may be required to function. The Frequency of 92 days for the Channel Functional Test is based upon the reliability analysis in NEDC-30851-P-A, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," October 1988. This reliability study found that the failure frequency curve for this type of instrumentation is relatively flat in the range of 30 to 124 days and starts a gradual increase after 124 days. Based on this finding, performing this testing more frequently than every 92 days

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_3 Labeled Comment/Discussion for ITS 3.3.2.1)

1. (continued)

does not significantly increase the probability of detecting a random failure of the RBM. The consequences of an accident will not be increased because the purpose of the RBM is to limit the a rod withdrawal error (RWE) and prevent violation of the Minimum Critical Power Ratio (MCPR) Safety Limit (SL) and the fuel cladding design limit of less than 1% plastic strain and has no function in mitigating the consequences of an accident. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

This proposed change will not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, tested, or inspected. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

The proposed change eliminates Specification 4.3.B.5 which requires a Functional Test of the Rod Block Monitor (RBM) "prior to withdrawal of the designated rod(s)" whenever "a limiting control rod pattern exists" and relies completely upon the Functional Test which is required every 92 days. The proposed change does not involve a significant reduction in a margin of safety because: two independent RBM channels will be Operable during any rod withdrawal except for short and infrequent periods when one channel is inoperable; and, deletion of this requirement allows taking credit for routine periodic tests in place of performing unscheduled testing whenever the potential exists that the RBM may be required to function. The Frequency of 92 days for the Channel Functional Test is based upon the reliability analysis in NEDC-30851-P-A, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," October 1988. This reliability study found that the failure frequency curve for this type of instrumentation is relatively flat in the range of 30 to 124 days and starts a gradual increase after 124 days. Based on this finding, performing this testing more frequently than every 92 days does not significantly increase the probability of detecting a random failure of the RBM. As a result, the change does not affect the current analysis assumptions. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_1 Labeled Comment/Discussion for ITS 3.3.3.1)

Proposed Condition B of Specification 3.3.3.1 provides Action when a channel is not restored to Operable status in 30 days as required by Condition A. The Action of Condition B specifies initiating action in accordance with Specification 5.6.6. The action to submit a report is appropriate, in lieu of the existing shutdown requirement, when one PAM channel has not been restored to Operable status, given the likelihood of unit conditions that would require the information that is provided by this instrumentation and the fact that the report identifies alternative actions to be taken before a complete loss of functional capability can occur.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change will revise the Required Actions for inoperable PAM channels that are not restored to service within the allowed out-of-service time. The PAM instrument channels are not assumed to be initiators of any analyzed event. The role of this instrumentation is in providing the operators information during and after an accident to allow them to take mitigating actions, thereby limiting consequences. The requested change does not allow continuous operation such that a single failure could result in a loss of function since the report requires an alternate means be established to monitor the affected parameter. Additionally, the consequences of an event occurring with the proposed actions are no worse than the consequences of an event occurring with the existing shutdown actions. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated.

   The proposed change does not necessitate a physical alteration of the plant (no new or different type of equipment will be installed) or changes in parameters governing normal operation. The proposed change will allow alternate means for monitoring the parameters be credited when PAM instrument channels are inoperable. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion for ITS 3.3.3.1) - continued

3. Does this change involve a significant reduction in a margin of safety?

The proposed action allowing continued operation provided alternate means of monitoring the affected parameters are identified and justified in a report to the NRC is acceptable based on the small probability of an event requiring the PAM instrumentation, the passive function of these instruments, and the alternate means of monitoring the affected parameter. This alternate means must be established and available to utilize the provisions of the proposed action. Providing this proposed action will minimize the potential for plant transients that can occur during plant shutdowns. As such, any reduction in a margin of safety will be offset by the benefit gained by avoiding an unnecessary plant shutdown transient when alternate monitoring capability exists. Therefore, this change does not involve a significant reduction in a margin of safety

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_2 Labeled Comment/Discussion for ITS 3.3.3.1)

PAM instruments are provided to assist in the diagnosis and preplanned actions required to mitigate design basis accidents which are assumed in Modes 1 and 2. The probability of an event in Modes 3, 4, or 5 that would require PAM instrumentation is sufficiently low that PAM instruments are not required in these Modes. As a result, for PAM instruments, the appropriate non-applicable Mode for shutdown actions is Mode 3. The Action to be in Mode 4 if at least one of the two Reactor Pressure or Suppression Chamber Water Temperature channels can not be restored to Operable status within the appropriate time has been revised to reflect placing the unit in the non-applicable Mode (Mode 3).

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change will limit the Applicability for PAM instruments to those Modes during which design basis events are assumed to occur. PAM instruments are not assumed to be initiators of any analyzed event. The role of these monitors is in providing the operators information during and after an accident to allow them to take mitigating actions, thereby limiting consequences. The variables monitored by the PAM instruments are related to the diagnosis and preplanned actions required to mitigate design basis accidents (DBAs). The applicable DBAs are assumed to occur in Modes 1 and 2. The revision to the Applicability (and subsequent shutdown action to the non-applicable Mode) is being made consistent with the applicable DBA analyses. As a result, DBA consequences are not increased by this change. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The proposed change does not necessitate a physical alteration of the plant (no new or different type of equipment will be installed) or changes in parameters governing normal operation. The proposed change will still ensure the monitors are maintained Operable in the Modes in which the applicable DBAs are assumed to occur. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_2 Labeled Comment/Discussion for ITS 3.3.3.1) - continued

3. Does this change involve a significant reduction in a margin of safety?

   The change to the Applicability is being made consistent with the safety analysis assumptions. The PAM instruments are provided to assist in the response to DBAs in the Modes which continue to be applicable. As such, the change still provides assurance the affected PAM instruments will be maintained Operable during conditions when the DBAs, which require these instruments for mitigation, are assumed to occur. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_3 Labeled Comment/Discussion for ITS 3.3.3.1)

The Action for a single inoperable Drywell High Range Radiation channel has been revised. Thirty days are proposed to allow for restoration of the inoperable channel or initiation of the alternate method of monitoring per proposed Condition B. The change from 72 hours for initiation of the alternate monitoring method and 7 days for restoration of the inoperable channel to 30 days for both actions is acceptable based on the availability of the remaining Operable Drywell High Range Radiation channel or Operable diverse instrument channels, the passive nature of the instrument (no required automatic action) and the low probability of an event requiring the PAM instrumentation during the interval.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change does not result in any hardware changes. The Drywell High Range Radiation channels are not assumed to be initiators of any analyzed event. The role of this instrumentation is in providing the operators information relative to drywell radiation levels during and after an accident to allow them to take mitigating actions, thereby limiting consequences. The requested change does not allow continuous operation such that a single failure could result in a loss of function. The change allows an additional time period to restore the inoperable channel or to establish an alternate means of monitoring, thus minimizing the potential for a shutdown transient. Additionally, the consequences of an event occurring during the proposed 30 day allowed outage time are the same as the consequences of an event occurring during the current allowed outage time. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The proposed change does not necessitate a physical alteration of the plant (no new or different type of equipment will be installed) or changes in parameters governing normal plant operation. The proposed change will allow 30 days for restoration of the inoperable channel or initiation of an alternate means of monitoring drywell radiation. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_3 Labeled Comment/Discussion for ITS 3.3.3.1) - continued

3. Does this change involve a significant reduction in a margin of safety:

   The proposed 30 day Completion Time to restore a Drywell High Range Radiation channel to Operable status or initiate an alternate means of monitoring is acceptable based on the passive nature of the instruments, the remaining Operable or diverse instrument channels and the small probability of an event requiring the Drywell High Range Radiation channel during this time period. Providing a 30 day Completion Time will minimize the potential for transients that can occur during shutdown by providing additional time to restore the channel or initiate alternate means of monitoring. As such, any reduction in a margin of safety by the extension of the Completion Time will be offset by the benefit gained by avoiding an unnecessary plant shutdown transient. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_4 Labeled Comment/Discussion for ITS 3.3.3.1)

The Actions have been changed for two Drywell High Range Radiation channels inoperable. Seven days are proposed to be allowed for restoration of one channel prior to initiating the alternate method of monitoring, instead of the existing requirement for initiation of the alternate method of monitoring within 72 hours and restoration of two channels to Operable status. The Completion Time of 7 days for restoration of one channel or initiation of the alternate method of monitoring is considered acceptable based on the relatively low probability of an event requiring PAM instrumentation, the passive function of the instruments, and the availability of alternate means to obtain the information.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change does not result in any hardware changes. The Drywell High Range initiators of any analyzed event. The role of this instrumentation is in providing the operators information relative to drywell radiation levels during and after an accident to allow them to take mitigating actions, thereby limiting consequences. The requested change does not allow continuous operation since the available alternate indications may not fully meet all performance qualification requirements applied to the Drywell High Range Radiation channels. The change allows 7 days to restore one inoperable channel or to initiate the alternate method of monitoring, thus minimizing the potential for a shutdown transient. Additionally, the consequences of an event occurring with the proposed actions are the same as the consequences of an event occurring within the allowed outage time of the current actions. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The proposed change does not necessitate a physical alteration of the plant (no new or different type of equipment will be installed) or changes in parameters governing normal plant operation. The proposed change, when two monitor channels are inoperable, will allow 7 days to restore one inoperable channel or initiate an alternate means of monitoring drywell radiation. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_4 Labeled Comment/Discussion for ITS 3.3.3.1) - continued

3. Does this change involve a significant reduction in a margin of safety?

   The proposed change to allow 7 days to restore one Drywell High Range Radiation channel to Operable status or initiate alternate means of monitoring is acceptable based on the small probability of an event requiring the Drywell High Range Radiation channels during the time period, the passive nature of the monitors, and the availability of alternate means to obtain the required information. Providing the proposed action will minimize the potential for plant transients that can occur during shutdown by providing additional time for the restoration of one monitor or the initiation of an alternate means of monitoring. As such, any reduction in a margin of safety resulting from the proposed change will be offset by the benefit gained by avoiding an unnecessary plant shutdown transient. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_5 Labeled Comment/Discussion for ITS 3.3.3.1)

The current restrictions on the allowed outage times for one or two instrument channels inoperable which require the availability of other instruments to monitor the affected variables have been deleted from the Specifications. The proposed Actions provide adequate assurance that information is available to the operator based on the availability of the remaining Technical Specifications monitoring channel (for the Condition of one channel inoperable) or the alternate monitoring methods (for the Condition of two channels inoperable). As such, no requirements for the availability of specific instruments need be specified for these Conditions.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change will not result in any hardware changes. The PAM instrument channels are not assumed to be initiators of any analyzed event. The role of this instrumentation is in providing the operators information during and after an accident to take mitigating actions, thereby limiting consequences. The requested change does not allow continuous operation when PAM instrument channels are inoperable. The allowed outage times of 30 days for one channel inoperable and 7 days for two channels inoperable are acceptable based on the passive function of the instruments and the low probability of a event requiring their Operability. The change deletes the restriction on the allowed outage times that other instruments be available in order to obtain the full time period. However, these other instruments do not fully meet the qualification requirements of the proposed PAM instrument channels to be included in Technical Specifications. Adequate assurance of the availability of information to the operator is provided by the proposed Actions. As such, these additional restrictions need not be specified in Technical Specifications. In addition, the consequences of an event occurring with the proposed actions are no worse than the consequences of an event occurring with the existing actions. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_5 Labeled Comment/Discussion for ITS 3.3.3.1) - continued

2. Does the change create the possibility of a new or different kind of accident form any accident previously evaluated?

   The proposed change does not necessitate a physical alteration of the plant (no new or different type of equipment will be installed) or changes in parameters governing normal operation. The proposed change deletes restriction on allowed outage times based on the availability of instruments which do not fully meet the qualification requirements of the PAM instruments to be included in Technical Specifications. However, the allowed outage times are still acceptably short given the passive function of the instruments and the low probability of an event requiring their Operability. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   The proposed change which effectively always allows a 30 day allowed outage time for one PAM channel inoperable and 7 days for two PAM channels inoperable is acceptable based on the small probability of an event requiring the PAM instruments during the time periods and the passive function of the instruments. Providing the proposed allowed outage times will minimize the potential for plant transients that can occur during shutdown by providing additional time for restoration of inoperable PAM instruments. As such, any reduction in a margin of safety resulting from the proposed change will be offset by the benefit gained by avoiding an unnecessary plant shutdown transient. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_6 Labeled Comment/Discussion for ITS 3.3.3.1)

The Instrument Checks performed once each shift and once per day have been replaced by a Channel Check performed once per 31 days. The change is made to conform to NUREG-1433 and is acceptable given the passive nature of these devices and the fact that the most common outcome of the performance of a surveillance is demonstrating the acceptance criteria are satisfied.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change does not result in any hardware changes. The PAM instrument Surveillances are not precursors to any analyzed accident. In addition, the PAM instruments are not assumed to be initiators of any analyzed event. The role of these instruments is in providing the operators information to allow them to take mitigating actions, thereby limiting consequences. The change extends the Surveillance interval to 31 days for performance of a Channel Check. However, industry operating experience has shown this interval to be acceptable for maintaining PAM instruments Operable. In addition, the most common outcome of the performance of a Surveillance is the demonstration that acceptance criteria are satisfied. As such, the consequences of an accident previously evaluated are not affected by this proposed change. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The proposed change does not necessitate a physical alteration of the plant (no new or different type of equipment will be installed) or changes in parameters governing normal plant operation. The proposed change will extend the Channel Check Surveillance interval but still provide assurance the PAM instruments will be maintained Operable. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_6 Labeled Comment/Discussion for ITS 3.3.3.1) - continued

3. Does this change involve a significant reduction in a margin of safety?

The proposed change to the PAM instrument Channel Check Surveillance interval is acceptable given the passive function of these devices and the fact that the most common outcome of the performance of a Surveillance is demonstrating the acceptance criteria are satisfied. In addition, the proposed 31 day Frequency of the Channel Check has been demonstrated, based on industry operating experience, to be adequate for maintaining PAM instrument Operability. Hence, any reduction in a margin of safety will be insignificant and will likely be offset by the benefit gained by allowing the operators to focus attention on more pertinent plant components. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_7 Labeled Comment/Discussion for ITS 3.3.3.1)

The Actions for one and two inoperable oxygen analyzer channels have been revised. Thirty days are proposed to be allowed for restoration of a single channel and seven days are proposed to be allowed for restoration of one channel when two channels are inoperable. The changes to the allowed outage times are considered acceptable based on the availability of the remaining Operable channel (one channel inoperable condition) or Operable diverse instrument channels (two channel inoperable condition), the passive nature of the instruments (no required automatic action) and the low probability of an event requiring PAM instrumentation during the intervals.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change does not result in any hardware changes. The oxygen analyzer channels are not assumed to be initiators of any analyzed event. The role of this instrumentation is in providing the operators information after an accident to allow them to take mitigating actions, thereby limiting consequences. The requested change does not allow continuous operation since the available alternate indications may not fully met all performance qualification requirements applied to PAM instrumentation. The change allows additional time to restore the inoperable analyzers, thus minimizing the potential for a shutdown transient. Additionally, the consequences of an event occurring during the proposed allowed outage times are the same as the consequences of an event occurring during the existing allowed outage times. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The proposed change does not necessitate a physical alteration of the plant (no new or different type of equipment will be installed) or change in parameters governing normal plant operation. The proposed change will allow 30 days to restore a single oxygen analyzer and 7 days to restore a single oxygen analyzer when two are inoperable. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_7 Labeled Comment/Discussion for ITS 3.3.3.1) - continued

3. Does this change involve a significant reduction in a margin of safety?

The proposed allowed outage times for oxygen analyzers are acceptable based on the small probability of an event requiring the oxygen analyzers during the time periods, the passive function of the analyzers and the availability of alternate means to obtain the information. Providing a 30 day allowed outage time for one inoperable oxygen analyzer and a 7 day allowed outage time for two inoperable oxygen analyzers will minimize the potential for plant transients that can occur during shutdown by providing additional time to restore the analyzers. As such, any reduction in a margin of safety by the extension of the allowed outage time will be offset by the benefit gained by avoiding an unnecessary plant shutdown transient. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_1 Labeled Comment/Discussion for ITS 3.3.4.1)

The Applicability requirement in proposed Specification 3.3.4.1 for the ATWS Recirculation Pump Trip will be at all times in Mode 1 instead of at all times in "Run or Startup Mode" as is required by existing Specification 3.2.G. The ATWS-RPT function is required to mitigate the consequences of a common mode failure of the Reactor Protection System scram function. The ATWS-RPT function reduces reactor power by tripping the recirculation pump breakers to reduce core flow. This function is required to be Operable in Mode 1 because the reactor may be producing significant power and the recirculation system could be at high flow. The function is not required in Startup (Mode 2) because the reactor is at low power and the recirculation system is at low flow; thus, both the need for and the effectiveness of the ATWS-RPT function in Mode 2 is significantly reduced. A commensurate change is also proposed which revises the shutdown action (proposed Required Action D.2) to be consistent with placing the unit in a Mode outside the Applicability. This proposed change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change does not involve any hardware changes. The ATWS-RPT instrumentation is not assumed to be an initiator of any analyzed event. The role of the ATWS-RPT instrumentation is in the mitigation of a ATWS event when the recirculation system is at high flow conditions and the reactor is at high power. Reducing the Applicability of the ATWS-RPT instrumentation from Mode 1 and 2 to Mode 1 and the commensurate change to the shutdown actions continue to ensure the instrumentation is available as assumed in the ATWS analyses. The ATWS-RPT instrumentation function is not required in Mode 2 since the reactor is at low power and the recirculation system is at low flow. Additionally, during Mode 2, other means of mitigating an ATWS event are available (Standby Liquid Control System and Alternate Rod Insertion) as assumed in the ATWS analysis. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion for ITS 3.3.4.1) - continued

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The proposed change does not necessitate a physical alteration of the plant (no new or different type of equipment will be installed) or changes in parameters governing normal plant operation. The proposed changes still ensure the ATWS-RPT instrumentation is required to be Operable as assumed in the ATWS analysis. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   The proposed change, which modifies the Applicability for the ATWS-RPT instrumentation from Mode 1 and 2 to Mode 1 and makes a commensurate change to the associated shutdown actions, does not involve a reduction in a margin of safety. The ATWS-RPT instrumentation is credited in the mitigation of an ATWS event when the reactor is at higher power and the recirculation system is at high flow conditions. As such, the ATWS-RPT instrumentation is not required to ensure operation is maintained within the bounds of the ATWS analysis. In addition, during Mode 2 other ATWS mitigation systems are available. Therefore, this change does not involve a significant reduction in a margin of safety.

<u>TECHNICAL CHANGES - LESS RESTRICTIVE</u> (continued)
(L_2 Labeled Comment/Discussion for ITS 3.3.4.1)

An additional Required Action is proposed to allow removal of the associated recirculation pump from service. Since this action accomplishes the functional purpose of the instrumentation and enables continued operation in a previously approved condition, this change is considered acceptable.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change does not involve any hardware changes. The ATWS-RPT instrumentation is not assumed to be an initiator of any analyzed event. The role of the ATWS-RPT instrumentation is in the mitigation and reduction of consequences of an ATWS event. The function of the ATWS-RPT instrumentation is to trip the recirculation pumps in the event of an ATWS. When the one or both of the recirculation pumps are removed from service the safety function of the associated ATWS-RPT instrumentation is satisfied and the instrumentation is no longer needed to trip the recirculation pumps. As a result, the consequences of a previously evaluated accident are not affected by this change. Therefore, the change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The proposed change does not necessitate a physical alteration of the plant (no new or different type of equipment will be installed) or changes in parameters governing normal operation. The proposed change will ensure the safety function of the ATWS-RPT instrumentation is satisfied in this condition. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_2 Labeled Comment/Discussion for ITS 3.3.4.1) - continued

3. Does this change involve a significant reduction in a margin of safety?

The proposed change, which provides an additional Required Action to allow removal of the associated recirculation pump from service when Required Actions and Completion Times are not met, does not involve a reduction in a margin of safety. With the proposed change, the ATWS-RPT instrumentation will no longer be required to trip the recirculation pump since the safety function will be fulfilled with the removal of the associated recirculation pump from service. Therefore, this change does not involve a significant reduction in a margin of safety since the safety functions continue to provide the required ATWS-RPT actuations, including single failure conditions.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_1 Labeled Comment/Discussion for ITS 3.3.5.1)

This change proposes to modify the Applicability for the LPCI Functions associated with the recirculation discharge valves by requiring them to be Operable in Modes 1, 2, and 3 with associated recirculation pump discharge valves open. This is reasonable since this Function is only required to be Operable when the recirculation valves are open which could hinder the coolant reaching the core. If the recirculation valves are closed then this Function is not required since its function is to close the recirculation valves. Also with the recirculation valve closed, the instruments function has been completed. Re-opening of the valve is a very controlled evolution, and could not be performed without strict administrative controls. This change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change does not involve any hardware changes. The affected ECCS instrumentation is not assumed to be an initiator of any analyzed event. The role of the affected ECCS instrumentation is in the mitigation and reduction of consequences of analyzed events. The function of the affected ECCS instrumentation is to close the recirculation pump discharge valves in the event of a recirculation line break to ensure LPCI pump flow diversion does not exceed the assumptions of the safety analysis. When the recirculation pump discharge valves are closed the safety function of the affected instrumentation is satisfied and instrumentation is no longer required to close the valves. As a result, the consequences of a previously evaluated accident are not affected by this change. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The proposed change does not necessitate a physical alteration of the plant (no new or different type of equipment will be installed) or changes in parameters governing normal plant operation. The proposed change still ensures the affected ECCS instrumentation is required to be Operable when

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion for ITS 3.3.5.1)

2. (continued)

it is necessary to perform the function assumed in the safety analysis. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

The proposed change, which modifies the Applicability of the LPCI instrumentation Functions which close the recirculation pump discharge valves, does not involve a reduction in a margin of safety. With the proposed change the affected ECCS instrumentation will no longer be required to be Operable when the recirculation pump discharge valves are closed. The safety function of the affected ECCS instrumentation is to close the recirculation pump discharge valves. As a result, with the associated valves closed, the safety function of the affected ECCS instrumentation is fulfilled. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_2 Labeled Comment/Discussion for ITS 3.3.5.1)

The Frequency for the Channel Calibration of the HPCI suction source transfer instrumentation (Condensate Storage Tank Level—Low and Suppression Pool Water Level—High) has been changed from 3 months to 24 months. These instruments are mechanical float type switches. Due to the construction and principles of operation of float type switches, the typical failure mode is to not operate. As a result, this type of failure would be detected during the quarterly Channel Functional Test. Therefore, extending the surveillance is considered acceptable and is consistent with other similar Surveillances.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change relaxes the Channel Calibration Frequency for the HPCI suction source transfer instrumentation from 3 months to 24 months. The proposed change does not affect the probability of an accident. The HPCI suction source transfer instrumentation is not assumed to be an initiator of any analyzed event. The role of this instrumentation is in mitigating and thereby limiting the consequences of analyzed accidents. The proposed change still provides assurance that HPCI suction source transfer instrumentation Operability is maintained consistent with analysis assumptions. The construction and principles of operation of these instruments support the fact that failures of these instruments would not be expected to go undetected during the extended Surveillance interval. The consequences of an accident are not affected by relaxing the frequency of the Surveillance since the consequences of a design basis accident with the HPCI suction source transfer instrumentation inoperable over the 3 month interval (due to an undetected failure) are the same as the consequences of a design basis accident with the HPCI suction source instrumentation inoperable for the relaxed surveillance interval. Additionally, the most common outcome of the performance of a Surveillance is the successful demonstration that the acceptance criteria are satisfied. This change will not alter assumptions relative to the mitigation of an accident or transient event. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_2 Labeled Comment/Discussion for ITS 3.3.5.1) - continued

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This change relaxes the Channel Calibration Frequency for the HPCI suction source transfer instrumentation. The proposed change to the Frequency will not create the possibility of an accident. This change will not physically alter the plant (no new or different type of equipment will be installed). The changes in methods governing normal plant operation are consistent with current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change relaxes the Channel Calibration Frequency for the HPCI suction source transfer instrumentation. The proposed change to the Frequency is acceptable since the proposed Frequency is adequate for ensuring the HPCI suction source transfer instrumentation is maintained Operable. In addition, the construction and principles of operation of these instruments support the fact that failures of these instruments would not be expected to go undetected during the extended Surveillance interval. Therefore, the margin of safety is not significantly reduced because the proposed changes to the Surveillance Frequency will continue to provide the necessary assurance that the HPCI suction source will automatically transfer when required. Also, this change is considered acceptable since the most common outcome of the performance of a Surveillance is the successful demonstration that the acceptance criteria are satisfied. The safety analysis assumptions will still be maintained, thus, no question of safety exists. Therefore, this change will not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_1 Labeled Comment/Discussion for ITS 3.3.6.1)

Existing Specification 3.2.A (Table 3.2.A, Items 3, 5, 7, 8 and 9 and associated Notes 2.A and 2.B, as applicable) requires an orderly load reduction to be initiated and the reactor to be in cold Shutdown in 24 hours if a required channel of Item 3 (MSL Isolation on Reactor Low Low Low Water Level) is inoperable and not placed in trip within the required time, and the main steam lines be isolated in 12 hours if a required channel of Item 5, 7, 8, or 9 (MSL Isolation on Main Steam Tunnel High Radiation, Main Steam Line High Flow, or Main Steam Tunnel High Temperature) is inoperable and not placed in trip within the required time period. Under the identical conditions, proposed Specification 3.3.6.1 (Table 3.3.6.1-1, Condition D) will allow the option of isolating the affected MSL in 12 hours or placing the reactor in Mode 3 within 12 hours and Mode 4 within 36 hours. This change is acceptable because placing the unit in Mode 3 within 12 hours and Mode 4 within 36 hours places the unit in a condition that is outside the Applicability for the function. This change is consistent with the BWR Standard Technical Specifications, NUREG 1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change modifies the Required Action when a channel of the MSIV isolation function from a Reactor Water Level, Main Steam Tunnel Radiation, Main Steam Line Flow or Main Steam Tunnel Temperature instrument is inoperable but cannot be placed in trip within the allowed out of service time. Instead of requiring an orderly load reduction to be initiated and the main steam lines isolated in 12 hours, the proposed change will allow the option of isolating the affected MSL in 12 hours or placing the reactor in Mode 3 within 12 hours and Mode 4 within 36 hours. The probability of an accident is not increased by this change because: this change does not involve changes to any plant hardware or plant operating procedures; and, the actions for inoperable Primary Containment Isolation Instrumentation are not assumed to be the initiator of any analyzed event. The time period to reach Mode 4 will not increase the probability of an accident because: the plant will be shutdown in the same time frame (Mode 3 within 12 hours) while also allowing for a more controlled cooldown which reduces thermal stress on components: and, the change reduces the chances for a plant transient which could challenge safety systems. The consequences of an accident will not be increased because: isolating the MSL within 12 hours accomplishes the required

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion for ITS 3.3.6.1)

1. (continued)

safety function of the inoperable instrument channel; the condition of operating with less than the full complement of MSIV isolation instrumentation is corrected within the same time period; and, the change will not allow continuous operation with plant conditions such that a single failure will preclude the affected isolation function from being performed. The time period to reach Mode 4 will not increase the consequences of an accident because: the consequences of an accident with a PCI instrument failure during the time period allowed to reach Mode 4 will be the same as those during the currently allowed time period. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

This proposed change will not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, tested, or inspected. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

The proposed change modifies the Required Action when a channel of the MSIV isolation function from a Reactor Water Level, Main Steam Tunnel Radiation, Main Steam Line Flow or Main Steam Tunnel Temperature instrument is inoperable but cannot be placed in trip within the allowed out of service time. Instead of requiring an orderly load reduction to be initiated and the main steam line isolated in 12 hours. The proposed change will allow the option of isolating the affected MSL in 12 hours or placing the reactor in Mode 3 within 12 hours and Mode 4 within 36 hours. The proposed change does not involve a significant reduction in a margin of safety because: isolating the MSL within 12 hours accomplishes the required safety function of the inoperable instrument channel; the condition of operating with less than the full complement of MSIV isolation instrumentation is corrected within the same time period; this change does not involve changes to any plant hardware or plant operating

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion for ITS 3.3.6.1)

3. (continued)

procedures; the actions for inoperable Primary Containment Isolation Instrumentation are not assumed to be the initiator of any analyzed event; the plant will be shutdown in the same time frame (Mode 3 within 12 hours) while also allowing for a more controlled cooldown which reduces thermal stress on components: and, the change reduces the chances for a plant transient which could challenge safety systems. As a result, the change does not affect the current analysis assumptions. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_2 Labeled Comment/Discussion for ITS 3.3.6.1)

Existing Table 3.2.A (Items 1 and 4 and associated Note 2.A.) requires that the Reactor be in Cold Shutdown within 24 hours of the determination that there are fewer than the minimum required number of Operable or tripped channels of Reactor Low Level (Proposed Function 2.a) or High Drywell Pressure (Proposed Function 2.b). Under the identical conditions, proposed Specification 3.3.6.1 (Table 3.3.6.1-1, Functions 2.a and 2.b and associated Condition H) will require that the reactor be in Mode 3 within 12 hours and Mode 4 within 36 hours. The change in Completion Time from Cold Shutdown within 24 hours to Mode 3 within 12 hours and Mode 4 within 36 hours is less restrictive even though it will require that the plant be shutdown (Mode 3) sooner than the existing specifications because it increases the amount of time before the reactor is outside the Mode of Applicability. This change is acceptable because the plant will be shutdown sooner while also allowing for a more controlled cooldown which reduces thermal stress on components and also reduces the chances for a plant transient which could challenge safety systems. Additionally, this change makes the Completion Times associated with inoperable PCI Instrumentation consistent with the Completion Times associated with an inoperable PCI valves in proposed Specification 3.6.1.3. This change is consistent with the BWR Standard Technical Specifications, NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change allows an additional 12 hours to reach Mode 4 when the Required Actions for inoperable Primary Containment Isolation (PCI) Instrumentation can not be performed or cannot be completed with the time specified. The probability of an accident is not increased by these changes because: this change does not involve changes to any plant hardware or plant operating procedures; inoperable Primary Containment Isolation Instrumentation is not assumed to be the initiator of any analyzed event; and, the plant will be shutdown sooner (Mode 3 within 12 hours) while also allowing for a more controlled cooldown which reduces thermal stress on components: and, the change reduces the chances for a plant transient which could challenge safety systems. The consequences of an accident will not be increased because: the consequences of an accident with a PCI instrument failure during the additional 12 hours allowed to reach Mode 4 will be the same as those during the 24 hours currently allowed; and, the change will not allow continuous operation with plant

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_2 Labeled Comment/Discussion for ITS 3.3.6.1)

1. (continued)

   conditions such that a single failure will preclude the affected isolation function from being performed. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This proposed change will not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, tested, or inspected. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   The proposed change allows an additional 12 hours to reach Mode 4 when the Required Actions for inoperable Primary Containment Isolation (PCI) Instrumentation can not be performed or cannot be completed with the time specified. The proposed change does not involve a significant reduction in a margin of safety because: this change does not involve changes to any plant hardware or plant operating procedures; inoperable Primary Containment Isolation Instrumentation is not assumed to be the initiator of any analyzed event; the change will not allow continuous operation with plant conditions such that a single failure will preclude the affected isolation function from being performed; and, the plant will be shutdown sooner (Mode 3 within 12 hours) while also allowing for a more controlled cooldown which reduces thermal stress on components and also reduces the chances for a plant transient which could challenge safety systems. As a result, the change does not affect the current analysis assumptions. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_3 Labeled Comment/Discussion for ITS 3.3.6.1)

Existing Specification 3.2.A (Table 3.2.A, Note 9) allows the setpoint of the MSL tunnel exhaust duct temperature function to be increased from the setpoint of approximately 200 degrees F to 250 degrees F for a period of 30 minutes to avoid a MSL isolation transient during a temporary loss of ventilation in the MSL tunnel. Proposed Specification 3.3.6.1 will not include this specific allowance; however, proposed Specification 3.3.6.1 will permit avoiding an MSL isolation during a temporary loss of MSL tunnel ventilation by deliberately entering into proposed Condition B and then raising the setpoints for the Main Steam Tunnel Temperature—High Function to 250 degrees F causing all channels of Main Steam Tunnel Temperature—High Function to be inoperable.

Use of entry in Condition B will allow Main Steam Tunnel Temperature—High setpoints to remain above the required setpoint for 1 hour instead of the 30 minutes allowed by existing Specification 3.2.A (Table 3.2.A, Note 9). This change is acceptable for the same reasons that proposed Specification 3.3.6.1 Conditions B and D are acceptable required actions for a complete loss of the function MSL Tunnel Temperature—High. Specifically, the period time that the setpoint will be above the allowance value is short and during this short period of time MSL isolation capability as protection against a MSL break is maintained by redundant functions including MSL Flow—High, MSL Pressure—Low, and Reactor Water Level—Low. Additionally, increasing the setpoint for the MSL tunnel exhaust duct high temperature from approximately 200 degrees F to 250 degrees F will not disable the MSL isolation on high tunnel temperature although it will increase the size and/or duration of the leak required to initiate the isolation. Finally, allowing this extended time will potentially avoid a plant transient caused by a plant shutdown and does not represent a significant decrease in safety. The compensatory actions associated with the loss of Main Steam Tunnel Temperature—High function currently located in Note 9 to Table 3.2.A are being relocated to the Bases.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change requires entry into the Conditions and Required Actions appropriate for a complete loss of MSL Tunnel Temperature—High Function instead of permitting a temporary increase to the Allowable Value for the function setpoint. As a result, this change extends the time from

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_3 Labeled Comment/Discussion for ITS 3.3.6.1)

1. (continued)

30 minutes to 1 hour that the setpoint for the Main Steam Tunnel Temperature—High Function may be raised from approximately 200 degrees F to 250 degrees F whenever necessary to avoid a MSL isolation transient during a temporary loss of ventilation in the MSL tunnel. This change results from the elimination of existing Specification 3.2.A (Table 3.2.A, Note 9) while avoiding an MSL isolation during a temporary loss of MSL tunnel ventilation by deliberately entering into proposed Condition B and then raising the setpoints for the Main Steam Tunnel Temperature—High Function to 250 degrees F causing all associated channels of the Function to be inoperable. The probability of an accident is not increased because the proposed change will not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, tested, or inspected. Temporarily raising instrument setpoints above the Allowable Values does not affect accident initiators. The proposed change does not affect the consequences of an accident because it is enveloped by proposed Specification 3.3.6.1, Conditions B and D, which allow a total of 13 hours of plant operation with a complete loss of MSL isolation capability. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

This change in the approach for responding to a temporary loss of main steam tunnel ventilation is consistent with the current safety analysis assumptions. The proposed change will not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, tested, or inspected. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

The proposed change requires entry into the Conditions and Required Actions appropriate for a complete loss of MSL Tunnel Temperature—High Function instead of permitting a temporary increase to the Allowance Value for the Function setpoint. As a result, this change extends the time (from 30 minutes to 1 hour) that the setpoint for the Main Steam Tunnel Temperature—High Function may be raised from approximately 200 degrees F to 250 degrees F whenever necessary to avoid a MSL isolation transient during a temporary loss of ventilation in the MSL tunnel. This change

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_3 Labeled Comment/Discussion for ITS 3.3.6.1)

3. (continued)

does not involve a reduction in a margin of safety because: the change in the approach for responding to a temporary loss of main steam tunnel ventilation is consistent with the current safety analysis assumptions; the period time that the setpoint will be above the Allowance Value is short and during this short period of time MSL isolation capability as protection against a MSL break is maintained by redundant functions including MSL Flow—High, MSL Pressure—Low, and Reactor Water Level—Low. Additionally, increasing the setpoint for the MSL tunnel exhaust duct high temperature from approximately 200 degrees F to 250 degrees F will not disable the MSL isolation on high tunnel temperature although it will increase the size and/or duration of the leak required to initiate the isolation. Also, the change provides the benefit of potentially avoiding a plant shutdown transient since the added 30 minutes allows more time to comply with the LCO instead of having to shut down. Therefore, this change will not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_4 Labeled Comment/Discussion for ITS 3.3.6.1)

The Frequency for the Safeguards Area High Temperature (HPCI and RCIC Compartments) Channel Calibration is being decreased from 3 months to 24 months. PBAPS operating history has shown this instrument to be continually reliable over a 24 month period. In addition, these instruments are the same as the HPCI and RCIC Steam Line High Temperature instruments, which already have a 24 month Frequency for the Channel Calibration. Therefore, it is acceptable to decrease the Frequency of this Surveillance. This change is also essentially consistent with NUREG-1433, which requires the SR to be performed on a refueling outage basis.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change relaxes the Surveillance Frequency for the Safeguards Area High Temperature Channel Calibration (existing Surveillance in Table 4.2.B) from 3 months to 24 months. The proposed change does not affect the probability of an accident. The Frequency for the Channel Calibration is not assumed to be an initiator of any analyzed event. The proposed change still provides assurance Safeguards Area High Temperature Instrumentation Operability is maintained consistent with analysis assumptions. Operating history has shown that Safeguards Area High Temperature Instrumentation would be continually reliable during the extended Surveillance interval. The consequences of an accident are not affected by relaxing the Frequency of the Surveillance since the consequences of a design basis accident with Safeguards Area High Temperature inoperable of the 3 month interval (due to an undetected failure) are the same as the consequences of a design basis accident with Safeguards Area High Temperature inoperable for the additional 21 month period. Additionally, the most common outcome of the performance of a Surveillance is the successful demonstration that the acceptance criteria are satisfied. This change will not alter assumptions relative to the mitigation of an accident or transient event. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_4 Labeled Comment/Discussion for ITS 3.3.6.1) - continued

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This change relaxes the Surveillance Frequency for the Safeguards Area High Temperature Channel Calibration. The proposed change to the Frequency will not create the possibility of an accident. This change will not physically alter the plant (no new or different type of equipment will be installed). The changes in methods governing normal plant operation are consistent with current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change relaxes the Surveillance Frequency for the Safeguards Area High Temperature Channel Calibration. The proposed change to the Frequency is acceptable since the proposed Frequency is adequate for ensuring the Safeguards Area High Temperature Instrumentation is maintained Operable. In addition, operating history has shown that Safeguards Area High Temperature Instrumentation would be continually reliable during the extended Surveillance interval. These instruments are also the same type as the HPCI and RCIC Steam Line High Temperature instruments, which already have a 24 month Frequency for the Channel Calibration. Therefore, the margin of safety is not significantly reduced because the proposed changes to the Surveillance Frequency will continue to provide the necessary assurance that the Safeguards Area High Temperature Isolation Instrumentation will perform as required. Also, this change is considered acceptable since the most common outcome of the performance of a Surveillance is the successful demonstration that the acceptance criteria are satisfied. The safety analysis assumptions will still be maintained, thus, no question of safety exists. Therefore, this change will not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_1 Labeled Comment/Discussion for ITS 3.3.6.2)

This proposed change (proposed Condition C) modifies current Action B by adding the options of declaring secondary containment isolation valves or the Standby Gas Treatment System inoperable. The current requirement requires the secondary containment to be isolated and the Standby Gas Treatment (SGT) System to be started. By allowing the associated secondary containment isolation valves (SCIVs) to be declared inoperable, the Actions of that Specification must be entered. This ensures the plant is within the bounds of the Technical Specifications and approved actions. The option to declare the SGT System inoperable is acceptable since this also ensures the plant is within the bounds of the Technical Specifications and approved actions. Declaring the associated SCIVs and SGT System inoperable is also acceptable since the Required Actions of the respective LCOs provide appropriate actions for the inoperable components. The 1 hour Completion Time is sufficient for plant operations personnel to establish required plant conditions or to declare the associated components inoperable without unnecessarily challenging plant systems. This change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change does not involve any hardware changes. The actions associated with secondary containment isolation instrumentation are not assumed in the initiation of any analyzed event. The proposed change replaces the actions associated with the inoperable instrumentation by providing the options of declaring secondary containment isolation valves or the Standby Gas Treatment System inoperable. The proposed actions ensure that the function of the instrumentation is performed or that approved Technical Specification Actions for the supported system are entered. The 1 hour Completion Time minimizes risk but is sufficient for plant personnel to establish the required conditions or declare the associated components inoperable without unnecessarily challenging plant systems. Operation within the bounds of the Technical Specifications and safety analyses is maintained with the proposed change. As such, the consequences of an accident previously evaluated are not affected by this change. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion for ITS 3.3.6.2) - continued

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The proposed change does not necessitate a physical alteration of the plant (no new or different type of equipment will be installed) or changes in parameters governing plant operation. The proposed change still ensures that operation is maintained within the bounds of the Technical Specifications and the safety analyses. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   The proposed change which revises the actions associated with inoperable secondary containment isolation instrumentation does not involve a reduction in a margin of safety. The proposed change ensures that appropriate compensatory measures are taken in the Condition commensurate with approved Technical Specifications Actions and the safety analyses in a time frame that minimizes risk while providing sufficient time for plant personnel to perform the actions without unnecessarily challenging plant systems. As such, the change provides the benefit of avoiding unnecessary challenges to plant systems when appropriate measures are available to compensate for the inoperable instrumentation. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_1 Labeled Comment/Discussion For ITS 3.3.7.1)

The Surveillances have been modified by a Note to indicate that when a channel is placed in an inoperable status solely for the performance of required Surveillances, entry into the associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated function maintains MCREV System initiation capability. This change is acceptable because: a) the Note only applies when the MCREVS initiation function is maintained by the redundant Control Room Air Intake Radiation—High channels; and b) the 6 hour period is based on GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications" (SER dated July 21, 1992). Confirmation of the applicability of GENE-770-06-1 to PBAPS for the MCREV system is documented in Technical Specification Change Request 90-03. This change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change provides a time period to allow for testing for instrumentation supporting the MCREV initiation function. The MCREV instrumentation is not assumed to be an initiator of any analyzed event. The instrumentation role is in mitigating and thereby limiting the post accident doses to the control room operators. The proposed change will not allow continuous operation such that a single failure will preclude the MCREV from actuating. There are no actual related modifications to any of the affected systems. However, the changes are expected to reduce the test related plant MCREV actuations. Therefore, there is no change in the probability of occurrence of a previously evaluated accident. General Electric topical report GENE-770-06-1 showed the effects of this change, which produced negligible impact, are bounded by previous analysis. PECO Energy concurs with this conclusion and has concluded that the results are also applicable to Peach Bottom Atomic Power Station Units 2 and 3. Further, the NRC has reviewed these reports and approved the conclusions on a generic basis. In addition, since MCREV System actuation capability will still exist, the consequences of an event occurring during the application of the proposed Note are the same as the consequences of an event occurring with current Technical Specification allowances. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion for ITS 3.3.7.1) - continued

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The design and functional operation of the affected instrumentation is not changed by the proposed Technical Specification changes. The proposed change affects only the time period allowed for testing and will not impact the manner in which the affected instrumentation provide plant protection or the function of monitoring system variables over the anticipated ranges for normal operation, anticipated operational occurrences or accident conditions. Further, the proposed change does not introduce any new modes of operation, make any physical modifications, or alter any operational setpoints. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   The change does not involve a reduction in a margin of safety since the allowance is only applicable for a short period of time (6 hours) provided MCREV System actuation capability is maintained. Additionally, the proposed change does not alter the manner in which safety limits, limiting safety system settings, or limiting conditions for operation are determined. The change does not alter any setpoints in the affected instrumentation or their design levels of redundancy. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_2 Labeled Comment/Discussion For ITS 3.3.7.1)

The Frequency for Surveillance 4.11.A.3 has been changed from 18 months to 24 months. In ITS, current Surveillance 4.11.A.3 requirements are addressed in the Logic System Functional Test (LSFT) for the MCREV System Instrumentation and the system functional test for the MCREV System. The current refueling outage, which is what the current test was originally based upon, is now 24 months. A review of the operating performance history of this requirement has shown that this SR has not failed due to a failure that is not related to an instrument failure (which would be detected during a CHANNEL FUNCTIONAL TEST) or a fan failure (which would be detected during the tests required by the VFTP). Therefore, extending the LSFT frequency is considered acceptable and is consistent with other similar Surveillances.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change relaxes the Surveillance Frequency for the LSFT requirements of the Main Control Room Emergency Ventilation (MCREV) System Instrumentation (existing Surveillance 4.11.A.3) from 18 months to 24 months. The proposed change does not affect the probability of an accident. The MCREV System Instrumentation is not assumed to be an initiator of any analyzed event. The role of the MCREV System Instrumentation is in mitigating and thereby limiting the post accident doses to the control room operators. The proposed change still provides assurance MCREV System Instrumentation Operability is maintained consistent with analysis assumptions. Operating history has shown that this Surveillance has not failed due to causes which would go undetected during the extended Surveillance interval. The consequences of an accident are not affected by relaxing the frequency of the Surveillance to perform the LSFT of the MCREV System Instrumentation since the consequences of a design basis accident with MCREV inoperable over the 18 month interval (due to an undetected failure) are the same as the consequences of a design basis accident with MCREV inoperable for the additional 6 month period. Additionally, the most common outcome of the performance of a Surveillance is the successful demonstration that the acceptance criteria are satisfied. This change will not alter assumptions relative to the mitigation of an accident or transient event. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_2 Labeled Comment/Discussion for ITS 3.3.7.1) - continued

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This change relaxes the Surveillance Frequency for the LSFT of the MCREV System Instrumentation. The proposed change to the Frequency will not create the possibility of an accident. This change will not physically alter the plant (no new or different type of equipment will be installed). The changes in methods governing normal plant operation are consistent with current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change relaxes the Surveillance Frequency for the LSFT of the MCREV System Instrumentation. The proposed change to the Frequency is acceptable since the proposed Frequency is adequate for ensuring the MCREV System Instrumentation is maintained Operable. In addition, operating history has shown that this Surveillance has not failed due to causes which go undetected during the extended Surveillance interval. Therefore, the margin of safety is not significantly reduced because the proposed changes to the Surveillance Frequency will continue to provide the necessary assurance that the MCREV System Instrumentation will automatically initiate when required. Also, this change is considered acceptable since the most common outcome of the performance of a Surveillance is the successful demonstration that the acceptance criteria are satisfied. The safety analysis assumptions will still be maintained, thus, no question of safety exists. Therefore, this change will not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_1 Labeled Comment/Discussion for ITS 3.3.8.1)

This change proposes to add a Note (Note 2) to the Surveillance Requirements which will allow a 2 hour delay from entering into the associated Conditions and Required Actions for a channel placed in an inoperable status solely for performance of required Surveillances provided the associated Function maintains initiation capability for three diesel generators or undervoltage transfer capability for three 4 kV emergency buses. The loss of Function is acceptable in this case since only three of the four DGs are required to start within the required time. The short period of time (2 hours) in this Condition will have no appreciable impact on risk. Also, upon completion of the Surveillance, or expiration of the 2 hour allowance, the channel must be returned to Operable status or the applicable Condition entered and Required Actions taken.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change does not result in any hardware or operating procedure changes. The LOP instrumentation is not assumed to be an initiator of any analyzed event. The instrumentations role is in mitigating and thereby limiting the consequences of design basis events. The instrumentation actuates to ensure the diesel generators are initiated to ensure power is provided to required safety systems during a design basis event. The proposed change will not allow continuous operation such that a single failure will preclude the diesel generators from mitigating the consequences of design basis accidents or transients. The allowance provided for testing is only applicable for a limited time (2 hours) provided the associated Function maintains initiation capability for 3 diesel generators. Since only 3 of the 4 diesel generators are necessary to start to mitigate the consequences of a design basis event, the consequences of an event occurring during the 2 hour time period are the same as the consequences of an event occurring during the Completion Time of the Actions. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion for ITS 3.3.8.1) - continued

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The proposed change will not involve any physical change to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, tested, or inspected. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   The proposed change will allow entry into the Conditions and Required Actions for a LOP instrument channel made inoperable for the performance of Surveillances to be delayed for 2 hours. This change does not involve a significant reduction in a margin of safety since the allowance is only applicable for a short period of time (2 hours) provided initiation capability of 3 diesel generators is maintained from the associated Function. Additionally, the proposed change does not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, or tested. In addition, the change does not affect current analysis assumptions. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_2 Labeled Comment/Discussion for ITS 3.3.8.1)

The proposed change requires the associated diesel generators (DGs) to be declared inoperable immediately if the Required Actions of Conditions A, B, C, or D cannot be met. The current requirements require that if the Actions cannot be met the reactor must be placed in the Shutdown Condition within 24 hours. By declaring the DG inoperable and taking the actions of the DG, the plant is within the bounds of the Technical Specifications and approved actions. Therefore, this action is appropriate since the LOP Instrumentation may be incapable of performing the intended function (starting the associated DGs), and the supported features (DGs) associated with the inoperable untripped channels must be declared inoperable immediately. This change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change does not involve any hardware changes. The actions associated with inoperable instrumentation are not assumed in the initiation of any analyzed event. The proposed change replaces the shutdown actions associated with inoperable instrumentation with actions to declare the supported system inoperable in this Condition. This ensures that the approved Technical Specification Actions for the supported system are entered. Operations within the bounds of Technical Specifications and safety analyses is maintained with the proposed change. As such, the consequences of an accident previously evaluated are not affected by this change. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The proposed change does not necessitate a physical alteration of the plant (no new or different type of equipment will be installed) or changes in parameters governing normal plant operation. The proposed change still ensures that operation is maintained within the bounds of the Technical Specifications and the safety analyses. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_2 Labeled Comment/Discussion for ITS 3.3.8.1) - continued

3. Does this change involve a significant reduction in a margin of safety?

The proposed change which replaces the shutdown actions associated with inoperable instrumentation with actions to declare the supported system inoperable does not involve a reduction in a margin of safety. The proposed change ensures that appropriate compensatory measures are taken in the Condition commensurate with approved Technical Specification Actions and the safety analyses. In addition, the proposed change provides the benefit of avoiding an unnecessary shutdown transient when appropriate measures are available to compensate for the inoperable instrumentation. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_3 Labeled Comment/Discussion for ITS 3.3.8.1)

This change proposes to extend the allowed outage times (AOTs) for Degraded Voltage High Setting and Degraded Voltage Non-LOCA Functions (Functions 3 and 5, respectively, of Table 3.3.8.1-1) from 1 hour to the following:

> 14 days in proposed Condition A when one or two Function 3 channels are inoperable on one 4 kV emergency bus; or
>
> 14 days in proposed Condition A when one or two Function 5 channels are inoperable on one 4 kV emergency bus; or
>
> 24 hours in proposed Condition B when one Function 3 channel is inoperable on each of two 4 kV emergency buses; or
>
> 24 hours in proposed Condition B when one Function 5 channel is inoperable on each of two 4 kV emergency buses; or
>
> 24 hours in proposed Condition B when one Function 3 channel is inoperable on one 4 kV emergency bus and one Function 5 channel is inoperable on a different 4 kV emergency bus.

During MODES 1, 2, and 3, four 4 kV emergency buses from the subject unit and at least two 4 kV emergency buses from the opposite unit are required to have OPERABLE LOP instrumentation. During other MODES or conditions, at least two 4 kV emergency buses from the subject unit and at least one 4 kV emergency bus from the opposite unit are required to have OPERABLE LOP instrumentation. The actual number of 4 kV emergency buses and, as a result, the LOP instrumentation channels required will vary depending on which components are being credited with satisfying Technical Specification requirements and from where these components are being powered. B

The 14 day allowed outage time (AOT) when one or two Function 3 channels or when one or two Function 5 channels are inoperable on one 4 kV emergency bus is acceptable because these relays provide only a marginal increase in the voltage monitoring scheme (there is only a small range where the relay protection provided by either of these relays does not overlap with other voltage monitoring relays). In this Condition, autotransfer capability from the normal offsite power source to the alternate power source may be lost from Function 3 or 5 channels for one 4 kV emergency bus. However, autotransfer capability will still be provided by the remaining Function 3 or 5 channels on the affected 4 kV emergency bus while maintaining adequate protection for equipment powered from the affected bus. Therefore, this change has no adverse impact on plant operation. In addition, the probability of the grid operating in this unprotected band is extremely remote. There has been no historical evidence of

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_3 Labeled Comment/Discussion for ITS 3.3.8.1) - continued

the grid operating in these bands for sufficient time that would have caused operation of these relays. Manual actions can also be taken on the 4 kV emergency bus with the inoperable channels as a result of observed automatic actions on the other 4 kV emergency buses with OPERABLE channels. (The number of other 4 kV emergency buses available with OPERABLE LOP instrumentation channels is based on the number of required 4 kV emergency buses discussed in the previous paragraph.) These actions (manually transferring the 4 kV emergency bus power supply to the alternate source) can be performed without detriment to plant equipment.

The 24 hour AOT when two 4 kV emergency buses have one required Function 3 channel inoperable, or when two 4 kV emergency buses have one required Function 5 channel inoperable, or when one 4 kV emergency bus has one required Function 3 channel inoperable and a different 4 kV emergency bus has one required Function 5 channel inoperable is acceptable based on the discussions above, except that in Condition B autotransfer capability may be lost for the two affected 4 kV emergency buses. Since the degradation addressed in Condition B is more severe than the degradation addressed in Condition A (two 4 kV emergency buses are impacted in Condition B, but only one 4 kV emergency bus is impacted in Condition A), the proposed AOT for Condition B is reduced to 24 hours from the proposed 14 day AOT specified for Condition A.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change adds two Actions for Function 3 and 5 channels. One of the proposed Actions will allow 14 days for restoration of the affected channels when one or two Function 3 channels or when one or two Function 5 channels are inoperable on one 4 kV emergency bus. The other proposed Action will allow 24 hours for restoration of the affected channels when two 4 kV emergency buses have one required Function 3 channel inoperable, or when two 4 kV emergency buses have one required Function 5 channel inoperable, or when one 4 kV emergency bus has one required Function 3 channel inoperable and a different 4 kV emergency bus has one required Function 5 channel inoperable. The current Technical Specifications allow 1 hour for restoration of the affected channels if one channel of either of these Functions per bus is inoperable. The proposed change does not affect the probability of an accident. The Function 3 and Function 5

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_3 Labeled Comment/Discussion for ITS 3.3.8.1)

1. (continued)

relay instrumentation channels are not assumed to be initiators of any analyzed event. The proposed allowed outage time extensions are acceptable because these degraded voltage instruments provide only a marginal increase in the protection provided by the voltage monitoring scheme (there is only a small range where the relay protection provided by either of these relays does not overlap with other voltage monitoring relays). In the proposed Conditions, autotransfer capability from the normal offsite power source to the alternate power source may be lost from Function 3 or 5 channels for one 4 kV emergency bus (for Condition A) or two 4 kV emergency buses (for Condition B). However, autotransfer capability will still be provided by the remaining Function 3 or 5 channels on the affected 4 kV emergency bus while maintaining adequate protection for equipment powered from the affected bus. Therefore, this change has no adverse impact on plant operation. In addition, the probability of the grid operating in this unprotected band is extremely remote. Manual actions can also be taken on the 4 kV emergency bus with the inoperable channels as a result of observed automatic actions on the other 4 kV emergency buses with OPERABLE channels. These actions (manually transferring the 4 kV emergency bus power supply to the alternate source) can be performed without detriment to plant equipment. In addition, the proposed change takes into consideration the diversity of the degraded voltage functions (there are four degraded voltage functions that function at various voltage levels). The consequences of an accident are not affected by this change since there are other protective relays available (although not all are set to trip at the same voltage setting) to detect a degraded voltage condition and provide equipment protection. The change will not alter assumptions relative to the mitigation of an accident or transient event. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated. B

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

The proposed change will not create the possibility of an accident. This change will not physically alter the plant (no new or different type of equipment will be installed). The changes in methods governing normal plant operation are consistent with the current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_3 Labeled Comment/Discussion for ITS 3.3.8.1) - continued

3. Does this change involve a significant reduction in a margin of safety?

This proposed change will not significantly reduce the margin of safety. The increased allowed outage times provided by the proposed change are acceptable based on the small probability of an event requiring the Function 3 or Function 5 degraded voltage instruments. In addition, these degraded voltage instruments provide only a marginal increase in the protection provided by the voltage monitoring scheme (there is only a small range where the relay protection provided by either of these relays does not overlap with other voltage monitoring relays). In the proposed Conditions, autotransfer capability from the normal offsite power source to the alternate power source may be lost from Function 3 or 5 channels for one 4 kV emergency bus (for Condition A) or two 4 kV emergency buses (for Condition B). However, autotransfer capability will still be provided by the remaining Function 3 or 5 channels on the affected 4 kV emergency bus while maintaining adequate protection for equipment powered from the affected bus. Therefore, this change has no adverse impact on plant operation. In addition, the proposed change is provides the benefit of avoiding a plant shutdown transient and/or unnecessary DG starts when other protective relays or manual action are available to respond to a degraded voltage condition. The safety analysis assumptions will still be maintained, thus no question of safety exists. Therefore, this change does not involve a significant reduction in margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_4 Labeled Comment/Discussion for ITS 3.3.8.1)

The change proposes to delete the requirement for a Channel Calibration on the undervoltage relay for the Loss of Voltage Function. The current Technical Specifications require a Channel Calibration once per 5 years. The design intent of the undervoltage relays for the Loss of Voltage Function is to monitor the gross availability of voltage on the respective emergency bus. The relay makes no determination concerning the quality of the voltage. The functional requirements are that the relays operate (de-energize) when there is no source of voltage to the bus, and that it not operate during the load sequencing. These results are achieved by the design process of selecting a device whose dropout is substantially below the anticipated lowest voltage observed during the sequencing, and by functionally verifying that it drops out when the bus is de-energized and that it does not drop out during the sequencing. A Channel Calibration is therefore not required for the undervoltage relay to perform to satisfy its safety function (starting the DG on a loss of voltage on the emergency bus). The Channel Functional Test will still be performed once per 24 months to ensure that the DG does start on a loss of voltage.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The change proposes to delete the requirement for a Channel Calibration on the undervoltage relay. The current Technical Specifications require a Channel Calibration once per 5 years. The proposed change does not affect the probability of an accident. The undervoltage relay instrumentation is not assumed to be an initiator of any analyzed event. The design intent of the undervoltage relays is to monitor the gross availability of voltage on the respective emergency bus. The relay makes no determination concerning the quality of the voltage. The functional requirements are that the relay operate (de-energize) when there is no source of voltage to the bus, and that it not operate during the load sequencing. These results are achieved by the design process of selecting a device whose dropout is substantially below the anticipated lowest voltage observed during the sequencing, and by functionally verifying that it drops out when the bus is de-energized and that it does not drop out during the sequencing. A Channel Calibration is therefore not required for the undervoltage relay to perform to satisfy its safety function which is to start the DG on a loss of voltage on the emergency bus. Thus, the proposed change still provides assurance the undervoltage relay will

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_4 Labeled Comment/Discussion for ITS 3.3.8.1)

1. (continued)

perform its function because the 24 month Channel Functional Test will still be performed. This change does not alter the analysis assumptions. The consequences of an accident are not affected by this change. This change will not alter assumptions relative to the mitigation of an accident or transient event. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

The proposed change will not create the possibility of an accident. This change will not physically alter the plant (no new or different type of equipment will be installed). The changes in methods governing normal plant operation are consistent with the current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

The change proposes to delete the requirement for a Channel Calibration on the undervoltage relay. The current Technical Specifications require a Channel Calibration once per 5 years. The margin of safety is not reduced by this change. The design intent of the undervoltage relays is to monitor the gross availability of voltage on the respective emergency bus. The relay makes no determination concerning the quality of the voltage. The functional requirements are that the relay operate (de-energize) when there is no source of voltage to the bus, and that it not operate during the load sequencing. These results are achieved by the design process of selecting a device whose dropout is substantially below the anticipated lowest voltage observed during the sequencing, and by functionally verifying that it drops out when the bus is de-energized and that it does not drop out during the sequencing. A Channel Calibration is therefore not required to ensure undervoltage relay performs to satisfy its safety function which is to start the DG on a loss of voltage to the emergency bus. The safety analysis assumptions will still be maintained, thus no question of safety exists. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_1 Labeled Comment/Discussion for ITS 3.3.8.2)

The Completion Time allowed to de-energize the bus when both electric power monitoring assemblies of a power supply are inoperable has been extended from 30 minutes to 1 hour. The 1 hour Completion Time is considered justified because it minimizes risk while allowing time for restoration or removal from service of the electric power monitoring assemblies.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change does not involve any hardware changes. The RPS electric power monitoring assemblies are not assumed to be initiators of any analyzed event. The role of the RPS electric power monitoring assemblies is ensuring that the equipment powered from the RPS buses can perform its intended function, thereby mitigating and limiting the consequences of analyzed events. The RPS electric power monitoring assemblies perform this role by acting to disconnect the RPS bus powered equipment from the power supply under conditions that could damage the equipment. The proposed change, which extends the time allowed to de-energize the affected bus from 30 minutes to 1 hour, does not allow continuous operation with the RPS electric power monitoring assemblies protective function lost. The 1 hour Completion Time for de-energizing the affected bus minimizes the risk associated with the loss while allowing time to remove the inoperable electric power monitoring assemblies from service in an orderly manner. In addition, the consequences of an event occurring during the proposed Completion Time are the same as the consequences of an event occurring during the current Completion Time. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion for ITS 3.3.8.2) - continued

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The proposed change does not necessitate a physical alteration of the plant (no new or different type of equipment will be installed) or changes in parameters governing normal operation. The proposed change will not allow continuous operation with the protective function of the electric power monitoring assemblies lost. The proposed change only allows a 1 hour time period in this condition before de-energization of the affected bus is required. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   The proposed 1 hour Completion Time for de-energizing the affected bus when both RPS electric power monitoring assemblies of a power supply are inoperable is acceptable based on the ability of the remaining RPS buses and the small probability of an event requiring the inoperable RPS electric power monitoring assemblies to protect the associated RPS bus powered equipment. Providing a 1 hour Completion Time will minimize the risk associated with the inoperable RPS electric power monitoring assemblies while allowing time to attempt restoration or de-energize the affected bus in an orderly manner. As such, any reduction in a margin of safety by providing a 1 hour Completion Time will be offset by the benefit gained from avoiding a potential plant transient initiating from bus de-energization which may cause a half scram or group isolation. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_2 Labeled Comment/Discussion for ITS 3.3.8.2)

A Note has been added to this Surveillance (SR 3.3.8.2.1) such that the Surveillance is only required to be performed when the unit is in Mode 4 $\geq$ 24 hours. Thus, the 6 month Frequency would not have to be met until a shutdown to Mode 4 for $\geq$ 24 hours occurs. The performance of this Surveillance could result in half-scrams, actual valve isolations, and other plant perturbations, since if the assembly opens, power is lost. The test requirement has been changed to allow it to be performed while shutdown to minimize the impact of this Surveillance on plant operation. This change is consistent with the guidance in NRC Generic Letter 91-09 and will reduce the possibility of inadvertent trips and challenges to safety systems.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change does not involve any hardware changes. The RPS electric power monitoring assemblies are not assumed to be initiators of any analyzed event. The role of the RPS electric power monitoring assemblies is ensuring that the equipment powered from the RPS buses can perform its intended function, thereby mitigating and limiting the consequences of analyzed events. The RPS electric power monitoring assemblies perform this role by acting to disconnect the RPS bus powered equipment from the power supply under conditions that could damage the equipment. The proposed change, which extends the Surveillance Frequency to once per 6 months if the unit is in Mode 4 for $\geq$ 24 hours, continues to ensure the RPS electric power monitoring assemblies are maintained Operable while reducing the possibility of inadvertent challenges to protection systems caused by performing this Surveillance at power. In addition, the most common outcome of the performance of a Surveillance is the successful demonstration that the acceptance criteria are satisfied. This change will not alter assumptions relative to the mitigation of an accident or transient event. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_2 Labeled Comment/Discussion for ITS 3.3.8.2) - continued

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The proposed change does not necessitate a physical alteration of the plant (no new or different type of equipment will be installed) or changes in parameters governing normal operation. The proposed change still provides adequate assurance the RPS electric power monitoring assemblies will be Operable when required. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change extends the Surveillance Frequency for the RPS electric power monitoring assemblies to once per 6 months if the unit is in Mode 4 for ≥ 24 hours. The margin of safety is not reduced since the Surveillance Frequency is adequate to ensure the RPS electric power monitoring assemblies are maintained Operable. This extension to the Surveillance Frequency is considered acceptable since the most common outcome of a Surveillance is the successful demonstration that the acceptance criteria are satisfied. In addition, this change provides the safety benefit of allowing the Surveillance to be performed with the unit shut down where the possibility of inadvertent trips and challenges to safety systems is reduced. It has been concluded that the benefit to safety of reducing the Frequency of testing during power operation more than offsets the risk to safety from relaxing the Surveillance Requirement to test RPS electric power monitoring assemblies during operation. Therefore, this change does not involve a significant reduction in a margin of safety.

ENVIRONMENTAL ASSESSMENT
SECTION 3.3--INSTRUMENTATION

This proposed Technical Specification Change has been evaluated against the criteria for and identification of licensing and regulatory actions requiring environmental assessment in accordance with 10 CFR 51.21. It has been determined that the proposed changes meet the criteria for categorical exclusion as provided for under 10 CFR 51.22(c)(9). The following is a discussion of how the proposed Technical Specification Change meets the criteria for categorical exclusion.

10 CFR 51.22 (c)(9): Although the proposed change involves changes to requirements with respect to inspection or surveillance requirements;

(i) the proposed change involves no Significant Hazards Consideration (refer to the No Significant Hazards Consideration section of this Technical Specification Change Request),

(ii) there is no significant change in the types or significant increase in the amounts of any effluents that may be released offsite since the proposed changes do not affect the generation of any radioactive effluents nor do they affect any of the permitted release paths, and

(iii) there is no significant increase in individual or cumulative occupational radiation exposure.

Accordingly, the proposed change meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Based on the aforementioned and pursuant to 10 CFR 51.22(b), no environmental assessment or environmental impact statement need be prepared in connection with issuance of an amendment to the Technical Specifications incorporating the proposed changes of this request.

TECHNICAL CHANGES - MORE RESTRICTIVE

This particular No Significant Hazards Considerations is for the changes labeled "Technical Changes - More Restrictive" for the conversion to NUREG-1433, Section 3.4--Reactor Coolant System. These changes incorporate more restrictive changes into the current Technical Specifications by either making current requirements more stringent or adding new requirements which currently do not exist. The following is a list of the more restrictive changes:

(M_1 and M_2 Labeled Comments/Discussions for ITS 3.4.1)

M_1 A new Surveillance Requirement has been added to verify core flow as a function of Thermal Power is in the "Unrestricted" Region of Figure 3.4.1-1 once per 24 hours. This ensures that core flow and Thermal Power are within appropriate limits to prevent uncontrolled power oscillations. This change represents an additional restriction on plant operations.

M_2 The flow imbalance limit is being reduced to 10% of rated core flow when operating at < 70% of rated core flow, and to 5% of rated core flow when operating at ≥ 70% of rated core flow. The current requirement is 15% mismatch of flow at the given flow conditions. While the limit appears to be less restrictive if core flow is ≤ 66% of rated core flow, it is more restrictive when > 66% of rated core flow (i.e., 15% x 66% or less is ≤ 10% of rated core flow), where the unit normally operates. In addition, currently, this is only a problem if there is an imbalance in combination with three other conditions (CTS 4.6.E.1 b, c, and d). The new requirement is separate from the other three, thus, actions will now be required if there is an imbalance by itself. Therefore, this change is considered more restrictive on plant operations.

(M_1 and M_2 Labeled Comments/Discussions for ITS 3.4.2)

M_1 Not used.

M_2 This change adds two requirements to the Surveillance to detect significant degradation in jet pump performance that precedes jet pump failure. The first requirement added would detect a change in the relationship between pump speed, and pump flow and loop flow (difference > 5%). A change in the relationship indicates a plug flow restriction, loss in pump hydraulic performance leakage, or new flow path between the recirculation pump discharge and jet pump nozzle. The second requirement added monitors the jet pump flow versus established patterns. Any deviations > 10% from normal are considered indicative of potential problem in the recirculation drive flow or jet pump system. These two added requirements to the

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1 and M_2 Labeled Comments/Discussions for ITS 3.4.2)

M_2 (cont'd) Surveillance help to detect significant degradation in jet pump performance that precedes jet pump failure. Requirements added to Surveillance Requirements constitute a more restrictive change. This change is consistent with NUREG-1433.

SIL-330 provides two alternate testing criteria (thus the deletion of current Surveillance 4.6.E.1.b). One method uses easy to perform surveillances with strict limits to initially screen jet pump Operability (the proposed changes above). If these limits are not met, another set of Surveillances exists (current Technical Specifications). Revising the Surveillances to include the stricter limits reflects a more restrictive change.

(M_1 Labeled Comment/Discussion for ITS 3.4.3)

M_1 Currently each SRV must be verified to open when manually actuated with reactor steam dome pressure ≥ 100 psig. The proposed change will replace the requirement for reactor steam dome pressure to be ≥ 100 psig with a note that states that the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. This change applies a time limit for performance of the Surveillance which constitutes a more restrictive change.

(M_1 Labeled Comment/Discussion for ITS 3.4.4)

M_1 Proposed LCO 3.4.4, RCS Operational Leakage, includes an additional requirement that no pressure boundary leakage is allowed because this condition is 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 considered pressure boundary leakage. In addition, shutdown Actions have been provided for the Condition of pressure boundary leakage. This change is consistent with NUREG-1433.

(M_1, M_2, M_3, and M_4 Labeled Comments/Discussions for ITS 3.4.5)

M_1 Existing Specifications 3.6.C.2 and 3.6.C.3 require that the drywell sump collection and flow monitoring system and the drywell atmosphere radioactivity monitor be Operable "during reactor power operation." Proposed LCO 3.4.5, RCS Leakage Detection

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, M_3, and M_4 Labeled Comments/Discussions for ITS 3.4.5)

M_1 (cont'd) Instrumentation, is applicable in Modes 1, 2, and 3. Proposed LCO 3.4.5, RCS Leakage Detection Instrumentation, governs all of the instrumentation needed to support implementation of proposed LCO 3.4.4, RCS Operational Leakage. Therefore, this more restrictive change is being made so that the Applicability of proposed LCO 3.4.5 will match the Applicability of proposed LCO 3.4.4.

M_2 Existing Specification 3.6.C.3 allows continued operation with the drywell atmosphere radioactivity monitor inoperable for "up to 30 days provided grab samples of the containment atmosphere are obtained and analyzed at least once every 24 hours." Proposed LCO 3.4.5, Required Action B.1, requires that grab samples be obtained every 12 hours whenever the drywell atmosphere radioactivity monitor is inoperable. With both gaseous and particulate primary containment atmospheric monitoring channels inoperable, grab samples of the primary containment atmosphere must be taken and analyzed to provide periodic leakage information. The 12 hour interval provides periodic information that is considered adequate to detect leakage provided at least one other form of leakage detection is available. This change is consistent with NUREG-1433.

M_3 Proposed LCO 3.4.5, ACTION D, adds an explicit requirement to enter proposed LCO 3.0.3 if all required leakage detection systems are inoperable. This is a more restrictive change because existing Specification 3.6.C.2, governing the drywell sump collection and flow monitoring system, and Specification 3.6.C.3, governing the drywell atmosphere radioactivity monitor, are independent and existing Technical Specifications will allow continued operation even if actions statements have been entered for both Specification 3.6.C.2 and Specification 3.6.C.3, (i.e. no operable leakage detection systems). This change is consistent with NUREG-1433.

M_4 Existing Specification 4.2.E and associated Table 4.2.E specifies the surveillance frequency of once/day for an Instrument Check for the Drywell Atmosphere Radiation Monitor. The frequency for an Instrument Check for the Drywell Atmosphere Radiation Monitor is being increased to every 12 hours to be consistent with NUREG-1433 and is more restrictive.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)
(M_1 and M_2 Labeled Comments/Discussions for ITS 3.4.6)

M_1 Existing Specification 3.6.B.1 is applicable "whenever the reactor is critical." Proposed LCO 3.4.6, RCS Specific Activity, is applicable in Mode 1, and Modes 2 and 3 with any main steam line not isolated. The Applicability for RCS specific activity requirements is based on limiting the consequences of a main steam line break outside containment. In Modes 2 and 3 with the MSIVs closed, RCS specific activity limits are not necessary since the main steam line break outside containment would not result in a release of reactor coolant outside containment. In Modes 4 and 5, no limits are required since the reactor is not pressurized and the potential for leakage is reduced. This change in Applicability is consistent with NUREG-1433.

M_2 Existing Specification 4.6.B.1 requires sampling reactor coolant chemistry for specific activity "during equilibrium power operation." Proposed SR 3.4.6.1, which contains the proposed requirements for sampling reactor coolant chemistry for specific activity, is modified by a note that requires this Surveillance to be performed only in Mode 1. This change is slightly more restrictive because sampling will be required whenever the reactor is in Mode 1 and not just when equilibrium conditions have been established. This change is consistent with NUREG-1433.

(M_1 Labeled Comment/Discussion for ITS 3.4.7 and ITS 3.4.8)

M_1 Technical Specifications will be added for the RHR shutdown cooling (SDC) subsystems in Modes 3 and 4. In Modes 3 and 4, the RHR shutdown cooling subsystem is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR shutdown cooling subsystem does not meet any of the specific deterministic criterion of the NRC Policy Statement; however, it was identified as an important contributor to risk reduction. The addition of new Specifications is a more restrictive change necessary to achieve consistency with NUREG-1433.

(M_1, M_2, M_3, and M_4 Labeled Comments/Discussions for ITS 3.4.9)

M_1 The reactor vessel temperature and reactor coolant pressure surveillance in existing Specification 4.6.A.2 has been modified to require the surveillance to be performed any time the RCS pressure and temperature conditions are undergoing changes, not just "whenever the shell temperature is below 220°F and the reactor vessel is not vented." This change is necessary since the potential

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, M_3, and M_4 Labeled Comments/Discussions for ITS 3.4.9)

M_1 (cont'd) exists for violating a P/T limit at all times. This change represents an additional restriction on plant operation and is consistent with NUREG-1433.

M_2 A new Surveillance Requirement has been added. SR 3.4.9.2 ensures the RCS pressure and temperature are within the criticality limits once within 15 minutes prior to control rod withdrawal for the purpose of achieving criticality. This is an additional restriction on plant operation and is consistent with NUREG-1433.

M_3 ACTIONS have been added (proposed ACTIONS A, B, and C) to provide direction when the LCO is not met. Currently, no real ACTIONS are provided since current Specification 3.0.C does not provide adequate compensatory measures when the RCS P/T limits are not met. These ACTIONS are consistent with NUREG-1433 and are additional restrictions on plant operation.

M_4 Three new Surveillance Frequencies have been added. SR 3.4.9.5 ensures the vessel head is not tensioned at too low a temperature once per 30 minutes. SRs 3.4.9.6 and 3.4.9.7 ensure the vessel and head flange temperatures do not exceed the minimum allowed temperature once per 30 minutes and once per 12 hours, respectively. These are additional restrictions on plant operation since the current requirements have no times specified.

(M_1 Labeled Comment/Discussion for ITS 3.4.10)

M_1 Proposed LCO 3.4.10, Reactor Steam Dome Pressure, and the associated Conditions, Required Actions, Completion Times, and a Surveillance Requirement have been added. The proposed LCO will require that reactor steam dome pressure be maintained less than or equal to 1053 psig while in Modes 1 and 2. A Surveillance will require that reactor steam dome pressure be verified within the proposed limit every 12 hours. If reactor steam dome pressure cannot be maintained within the proposed limit and cannot be restored within the required Completion Time, the reactor must be placed in Mode 3 within 12 hours. The reactor steam dome pressure limit of less than or equal to 1053 psig is an assumption used in the Power Rerate Safety Analysis for Peach Bottom 2 & 3. This proposed additional restriction is consistent with NUREG-1433 and helps ensure the safety analysis assumptions are maintained.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change provides more stringent requirements than previously existed in the Technical Specifications. The more stringent requirements will not result in operation that will increase the probability of initiating an analyzed event. If anything the new requirements may decrease the probability or consequences of an analyzed event by incorporating the more restrictive changes discussed above. The change will not alter assumptions relative to mitigation of an accident or transient event. The more restrictive requirements will not alter the operation of process variables, structures, systems, or components as described in the safety analyses. The change has been confirmed to ensure no previously evaluated accident has been adversely affected. Therefore, the change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   Making existing requirements more restrictive and adding more restrictive requirements to the Technical Specifications will not alter the plant configuration (no new or different type of equipment will be installed) or make changes in methods governing normal plant operation. The change does impose different requirements. However, the change is consistent with assumptions made in the safety analyses. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   Adding new requirements and making existing ones more restrictive either increases or does not affect the margin of safety. The change does not impact any safety analysis assumptions. As such, no question of safety is involved. Therefore, this change will not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - RELOCATIONS

This proposed change relocates requirements from the Technical Specifications to a licensee controlled document. These changes are labeled "Technical Changes - Relocations." These changes are listed below.

(R_1, R_2, R_3, and R_4 Labeled Comments/Discussions for ITS 3.4.1)

R_1 The requirement that, "Following one-pump operation, the discharge valve of the low speed pump may not be opened unless the speed of the faster pump is less than 50% of its rated speed," is being relocated to plant procedures. Specific instructions on the operation of equipment is being relocated from the improved Technical Specification. This change is consistent with NUREG-1433. Any changes to this requirement will require a 10 CFR 50.59 evaluation.

R_2 This change relocates the requirement to obtain baseline APRM and LPRM neutron flux noise data. This requirement will be relocated to plant procedures. Placing this requirement in plant procedures provides assurance it will be appropriately maintained since changes will be controlled by 10 CFR 50.59. In addition, the Technical Specification will still require, if operating in a region of potential thermal hydraulic instability, for APRM and LPRM noise levels to be verified to be ≤ 3 times baseline noise levels. As such, the requirement to have a baseline will still exist in Technical Specifications.

R_3 The requirements to "immediately initiate action" have been relocated to the Bases. This is considered acceptable since Technical Specifications will still require the restoration of the requirements within a specific time period. In addition, all changes to the Bases will require a 10 CFR 50.59 evaluation. As such, adequate control of the relocated requirements will be maintained.

R_4 The specific details regarding the determination of LPRM neutron flux noise levels (which LPRMs to use and their location) have been relocated to the Bases. Placing these details in the Bases provides assurance they will be maintained. Changes to the Bases will be controlled using 10 CFR 50.59.

TECHNICAL CHANGES - RELOCATIONS (continued)
(R_1 and R_2 Labeled Comments/Discussions for ITS 3.4.2)

R_1 This change relocates specific information from Specifications 3.6.E.2, 3.6.E.3, and 3.6.E.4 related to systems (e.g. "indicated core flow is the sum of the flow indication from each of the 20 jet pumps") to a licensee controlled document. This information will not be changed without a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_2 This change relocates the requirement to obtain baseline data required to evaluate jet pump Operability. This requirement could be relocated to a licensee controlled document (i.e. the startup testing program) for two loop operation and a single loop procedure for single loop operation. Also, in order to have established patterns a baseline must exist. Any changes to these requirements will require a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

(R_1, R_2, R_3, and R_4 Labeled Comments/Discussions for ITS 3.4.3)

R_1 The requirement to disassemble and inspect one SRV every 24 months will be relocated. Maintenance related activities are being relocated out of Technical Specifications. Therefore, this requirement is being relocated into plant procedures. Any changes to this requirement will require a 10 CFR 50.59 evaluation. This change is consistent with NUREG-1433.

R_2 The SRV bellows instrumentation does not necessarily relate directly to the respective system Operability. In general, the BWR Standard Technical Specifications, NUREG-1433, do not specify indication only equipment to be Operable to support Operability of a system or component. Control of the availability of, and necessary compensatory activities if not available, for indications, monitoring instruments, and alarms are addressed by plant operational procedures and policies. Therefore this instrumentation, along with the supporting Surveillances are removed from the Technical Specifications. Any changes to this requirement will require a 10 CFR 50.59 evaluation. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, and R_4 Labeled Comments/Discussions for ITS 3.4.3) - continued

R_3 The specific instruction on how to verify that the SRV is manually opened is being relocated. Specific instructions on how to perform surveillances are being relocated out of Technical Specifications. Therefore, this requirement will be relocated into the Technical Specification Bases and plant procedures. Any changes to this requirement will require a 10 CFR 50.59 evaluation. This change is consistent with NUREG-1433.

R_4 The requirement to perform an inspection for leakage of the accumulators and air piping for the SRVs once per operating cycle will be relocated to plant procedures. Any changes to this requirement will require a 10 CFR 50.59 evaluation. This change is consistent with NUREG-1433.

(R_1 and R_2 Labeled Comments/Discussions for ITS 3.4.5)

R_1 Existing Specification 4.6.C.1 identifies that RCS leakage shall be determined "by the primary containment (Drywell) sump collection and flow monitoring system." Details of the methods for performing surveillance are being relocated to plant procedures and will be controlled in accordance with 10 CFR 50.59.

R_2 Existing Specification 4.6.C.2 requires that drywell atmosphere radioactivity levels shall be monitored and recorded at least once per day. The details relating to recording the readings has been relocated to the procedures. The CHANNEL CHECK requirement (monitoring) is still maintained as SR 3.4.5.1. Changes to the procedures will be controlled in accordance with 10 CFR 50.59.

(R_1 Labeled Comment/Discussion for ITS 3.4.6)

R_1 Existing Specification 4.6.B.1 contains requirements for reactor coolant and offgas system sampling during startup, following significant power level changes, and following significant changes in offgas radiation levels. The results of any of these samples are intended to determine if RCS specific activity is exceeding specified limits. Experience has determined that the weekly sampling required by proposed SR 3.4.6.1 and requirements for monitoring main steam line and offgas radiation levels is sufficient to ensure RCS specific activity levels are not exceeded. Therefore, RCS specific activity requirements for sampling stack gas, offgas

TECHNICAL CHANGES - RELOCATIONS

(R_1 Labeled Comment/Discussion for ITS 3.4.6)

R_1 (cont'd) and main steam line are being relocated to plant procedures and will be controlled in accordance with 10 CFR 50.59. In addition, the criteria for when specific activity has been returned to limits (until two successive samples indicate a decreasing trend below the limit with at least 3 consecutive samples being taken) has been relocated to plant procedures and will be controlled by 10 CFR 50.59. This change is consistent with NUREG-1433.

(R_1, R_2, R_3, and R_4 Labeled Comments/Discussions for ITS 3.4.9)

R_1 Not used. B

R_2 The criteria for when the RCS temperature surveillance for heatup and cooldowns may be discontinued (until the difference between any 2 readings taken over a 45 minute period is less than 5°F) have been relocated to plant procedures. Changes to these procedures will be controlled using 10 CFR 50.59.

R_3 The specific RCS locations (bottom head drain and recirculation loops A and B) for monitoring temperature during heatups and cooldowns have been relocated to plant surveillance procedures. Changes to these procedures will be controlled using 10 CFR 50.59.

R_4 Reactor vessel test specimen location and associated details regarding the sample program have been relocated to the UFSAR. Changes to these details in the UFSAR will be controlled using 10 CFR 50.59.

TECHNICAL CHANGES - RELOCATIONS (continued)
(R_1 Labeled Comment/Discussion for CTS 3.6.B.2)

R_1 Existing Specification 3.6.B.2 establishes the controls for reactor water quality including: chloride concentration; conductivity; and pH. The chemistry limits are provided to prevent long term component degradation and provide long term maintenance of acceptable structural conditions of the system. The associated surveillances are not required to ensure immediate Operability of the Reactor Coolant System. Therefore, this requirement specified in current Specifications does not satisfy the NRC Policy Statement Technical Specification Screening Criteria. This requirement will be relocated to a licensee controlled document. Changes to this requirement will require a 10 CFR 50.59 evaluation. This change is consistent with NUREG-1433.

(R_1 Labeled Comment/Discussion for CTS 3.6.G)

R_1 The structural integrity inspections are provided to prevent long term component degradation and provide long term maintenance of acceptable structural conditions of the system. The associated inspections are not required to ensure immediate Operability of the system. Therefore, this requirement specified in current Specifications does not satisfy the NRC Policy Statement Technical Specification Screening Criteria. This requirement will be relocated to a licensee controlled document. Changes to this requirement will require a 10 CFR 50.59 evaluation. This change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This proposed change relocates requirements from the Technical Specifications to a licensee controlled document. The licensee controlled document containing the relocated requirements will be maintained using the provisions of 10 CFR 50.59 and is subject to the change control process in the Administrative Controls Section of the Technical

TECHNICAL CHANGES - RELOCATIONS (continued)

1. (continued)

Specifications. Since any changes to a licensee controlled document will be evaluated per 10 CFR 50.59, no increase (significant or insignificant) in the probability or consequences of an accident previously evaluated will be allowed. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

This change relocates requirements to a licensee controlled document. This change will not alter the plant configuration (no new or different type of equipment will be installed) or changes in methods governing normal plant operation. This change will not impose different requirements and adequate control of information will be maintained. This change will not alter assumptions made in the safety analysis and licensing basis. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

This change relocates requirements from the Technical Specifications to a licensee controlled document. This change will not reduce a margin of safety since it has no impact on any safety analysis assumptions. In addition, the requirements to be transposed from the Technical Specifications to the licensee controlled document are the same as the existing Technical Specifications. Since any future changes to this licensee controlled document will be evaluated per the requirements of 10 CFR 50.59, no reduction (significant or insignificant) in a margin of safety will be allowed. Therefore, this change will not involve a significant reduction in a margin of safety.

The existing requirement for NRC review and approval of revisions, in accordance with 10 CFR 50.90, to these details and requirements proposed for relocation, does not have a specific margin of safety upon which to evaluate. However, since the proposed change is consistent with the BWR Standard Technical Specifications (NUREG-1433 approved by the NRC Staff) and the change controls for proposed relocated details and requirements provide an equivalent level of regulatory authority, revising the Technical Specifications to reflect the approved level of detail and requirements ensures no reduction in the margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion FOR ITS 3.4.1)

A Note to LCO 3.4.1 which states "Required limit modifications for single recirculation loop operation may be delayed for up to 12 hours after transition from two recirculation loop operation to single loop operation" is proposed to be added to the PBAPS Technical Specifications. The addition of the proposed Note will eliminate any confusion brought on by the inconsistency with Specification 3.3.1.1, Reactor Protection System Instrumentation, and the need to enter Condition D of Specification 3.4.1, Recirculation Loops Operating, just to transition from two loop operation to single loop operation (Condition D allows 24 hours to reset the APRM settings to the single loop values, but Specification 3.3.1.1 does not provide a 24 hour Completion Time for inoperable APRM channels). The proposed Note extends the time to implement the single loop operation requirements from 6 hours to 12 hours. This change also relaxes the allowed outage time from 6 hours to 24 hours to comply with the LCO when the reason for non-compliance is not related to thermal hydraulic stability. Relaxing the time to complete limit modifications for single loop operation or to restore compliance with the LCO in this condition is reasonable considering the low probability of an accident occurring during this period, the time required to perform the Required Action and the frequent core monitoring by operators allowing abrupt changes in core flow conditions to be quickly detected. The consequences of an accident are unchanged by adding additional time to complete limit modifications for single loop operation or to restore compliance with the LCO. Also, allowing this extended time will potentially avoid a plant transient caused by a plant shutdown and does not represent a significant decrease in safety.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed Note to LCO 3.4.1 extends the time to implement single loop operation requirements from 6 hours to 12 hours. This change also relaxes the allowed outage time from 6 hours to 24 hours to comply with the LCO when the reasons for non-compliance is not related to thermal hydraulic stability. The proposed change does not increase the probability of an accident. The time allowed to restore a second recirculation loop to operation or to satisfy single recirculation loop operation limits is not assumed in the initiation of an analyzed event. The change does not allow

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion FOR ITS 3.4.1)

1. (continued)

continuous operation but provides a time period which is acceptably short taking into consideration the small probability of an event occurring when a second recirculation loop is not operating and single loop operation limits are not met. Allowing additional time to comply with the LCO will not significantly increase the consequences of an accident. The consequences of an event occurring will be the same for proposed time periods as for the current 6 hours. This change will not alter assumptions relative to the mitigation of an accident or transient event. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

The proposed Note to LCO 3.4.1 extends the time to implement single loop operation requirements from 6 hours to 12 hours. This change also relaxes the allowed outage time from 6 hours to 24 hours to comply with the LCO. This change will not physically alter the plant (no new or different type of equipment will be installed). The changes in methods governing normal plant operation are consistent with the current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

The proposed Note to LCO 3.4.1 extends the time to implement single loop operation requirements from 6 hours to 12 hours. This change also relaxes the allowed outage time from 6 hours to 24 hours to comply with the LCO when the reason for non-compliance is not related to thermal hydraulic stability. The increased time allowed to restore the second recirculation loop or to satisfy single recirculation loop operation limits is acceptable based on the small probability of an event occurring requiring recirculation loop operation to be within limits and the desire to minimize plant transients. While recirculation loop operation with matched flows is assumed in the LOCA analysis, allowing additional time to comply with the LCO does not significantly decrease the margin of safety. Also, the change provides the benefit of potentially avoiding a plant shutdown transient. The change allows more time to comply with the LCO instead of having to shut down. A plant shutdown is considered a transient due to the thermal effects it has on plant equipment. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_2 Labeled Comment/Discussion for ITS 3.4.1)

This change relaxes the time required to bring the plant to a Mode in which the LCO does not apply. It changes the time to bring the plant to Mode 3 from 6 hours to 12 hours. This proposed Completion Time is based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. The probability of an accident is not increased because the time allowed to restore the recirculation loops is not a precursor to any accident. Also the consequences of an accident occurring in the additional 6 hours allowed to reach Mode 3 are unchanged. The additional time also allows for a more controlled reduction in power.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change relaxes the time required to bring the plant to a Mode in which the LCO does not apply. It changes the shutdown Completion Time to bring the plant to Mode 3 from 6 hours to 12 hours. The proposed change will not increase the probability of an accident. The shutdown Completion Time is not assumed to be an initiator of any analyzed event. Allowing 6 additional hours to bring the plant to a nonapplicable Mode will not significantly increase the consequences of an accident. The chances of an event occurring are the same in the additional 6 hour period as they are in the first 6 hour period. Also, the consequences of an event occurring will be the same for 12 hours as for 6 hours. The 12 hour time period however, will allow additional time to reduce power to bring the plant to Mode 3. This allows a more controlled shutdown which reduces the possibility of a transient due to shutting down the plant. This change will not alter assumptions relative to the mitigation of an accident or transient event. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_2 Labeled Comment/Discussion for ITS 3.4.1) - continued

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This change relaxes the time required to bring the plant to a Mode in which the LCO does not apply. It changes the time to bring the plant to Mode 3 from 6 hours to 12 hours. The additional 6 hours to shutdown the plant will not create the possibility of a new or different accident. Also, this change will not physically alter the plant (no new or different type of equipment will be installed). The changes in methods governing normal plant operation are consistent with the current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change relaxes the time required to bring the plant to a Mode in which the LCO does not apply. It changes the time to bring the plant to Mode 3 from 6 hours to 12 hours. The increased time allowed to reach Mode 3 when the recirculation loop LCO is not met is acceptable based on the low probability of an event requiring the recirculation loops to be in operation with matched flows and the desire to minimize plant transients. While recirculation loop operation with matched flow is assumed in the LOCA analysis, allowing an additional 6 hours to shutdown will not significantly decrease the margin of safety. The added 6 hours allowed to shut down allows more time to shut down in a controlled manner which reduces the effects of the shutdown. A shutdown is considered a transient due to the thermal effects it has on plant equipment. Thus the additional 6 hours is acceptable. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_3 Labeled Comment/Discussion for ITS 3.4.1)

This change adds a note which states the Surveillance is not required to be performed until 24 hours after both recirculation loops are in operation. The Surveillance is not required to be performed until both loops are operating since the mismatch limits are meaningless during single loop or natural circulation operation. Also, the Surveillance is allowed to be delayed 24 hours after both recirculation loops are operating. This allows for time to establish appropriate conditions for the test to be performed.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change adds a note to allow the Surveillance which states the surveillance is not required to be performed until 24 hours after both recirculation loops are in operation to ensure adequate data retrieval. The proposed change does not increase the probability of an accident. The recirculation loops are not assumed to be an initiator of any analyzed event. The note allows time after both loops are in service to establish appropriate conditions for the test to be performed. Thus the consequences of an accident are not increased because the proposed change provides confirmation of the Operability of recirculation loops at the earliest opportunity when the recirculation loops are in operation. This change will not alter assumptions relative to the mitigation of an accident or transient event. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This change will not create the possibility of an accident. This change adds a note to allow the Surveillance which states the surveillance is not required to be performed until 24 hours after both recirculation loops are in operation. The proposed changes to the Frequency will not create the possibility of an accident. The Surveillance Requirement is being performed to confirm the Operability of the recirculation loops at the earliest opportunity when the recirculation loops are in operation to ensure adequate data retrieval. This change will not physically alter the

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_3 Labeled Comment/Discussion for ITS 3.4.1)

2. (continued)

plant (no new or different type of equipment will be installed). The changes in methods governing normal plant operation are consistent with the current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

This change adds a note to allow the Surveillance which states the surveillance is not required to be performed until 24 hours after both recirculation loops are in operation. The margin of safety is not significantly reduced because the proposed changes to the Surveillance Frequency will continue to provide the necessary assurance of Operability of the recirculation loops at the earliest opportunity. This change effectively extends the initial Surveillance Requirement by allowing both recirculation loops to be in operation for 24 hours prior to performing the Surveillance. This is considered acceptable since the most common outcome of the performance of a surveillance is the successful demonstration that the acceptance criteria are satisfied. In addition, the change provides the benefit of allowing the surveillance to be postponed until plant conditions exist where the surveillance can be performed. The safety analysis assumptions will still be maintained, thus no question of safety exist. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_1 Labeled Comment/Discussion for ITS 3.4.2)

This change adds two notes to the Surveillance which relax the Surveillance Frequency to allow a 4 hour delay in performance of the Surveillance after the associated recirculation loop is in operation and an exemption to the performance of the Surveillance until 24 hours after the plant reaches 25% RTP. The first note allows the Surveillance not to be performed until 4 hours after the associated recirculation loop is in operation, because these checks can only be performed during jet pump operation. The four hours is an acceptable time to establish conditions appropriate for data collection and evaluation. The second note allows the Surveillance to not be performed when THERMAL POWER is ≤ 25% of RTP. During low flow conditions, jet pump noise approaches the threshold response of the associated flow instrumentation and precludes the collection of the repeatable and meaningful data. Currently, the Surveillance is required whenever there is recirculation flow and the reactor is in the startup or run Modes.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change adds two notes to the Surveillance which relax the Surveillance Frequency to allow a 4 hour delay in performance of the Surveillance after the associated recirculation loop is in operation and an exemption to the performance of the Surveillance until 24 hours after the plant reaches 25% RTP. The proposed change does not increase the probability of an accident. The jet pumps are not assumed to be an initiator of any analyzed event. The notes allow time after the loop is in service to establish appropriate conditions for the test to be performed. The Surveillance is not required to be performed at powers less than 25% because during low flow conditions, jet pump noise approaches the threshold response of the associated flow instrumentation and precludes the collection of meaningful data. The proposed change provides confirmation of the Operability of the jet pumps at the earliest opportunity when the jet pumps are required. In addition, the most common outcome of the performance of a Surveillance is the successful demonstration that the acceptance criteria are satisfied. As a result, the consequences of an accident are not affected by this change. This change will not alter assumptions relative to the mitigation of an

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion for ITS 3.4.2)

1. (continued)

accident or transient event. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

This change will not create the possibility of an accident. This change adds two notes to the Surveillance which relaxes the Surveillance Frequency to allow a 4 hour delay in performance of the Surveillance after the associated recirculation loop is in operation and an exemption to the performance of the surveillance until 24 hours after the plant reaches 25% RTP. The proposed changes to the Frequency will not create the possibility of an accident. The Surveillance Requirement is being performed to confirm of the Operability of the jet pumps at the earliest opportunity when the jet pumps are required. This change will not physically alter the plant (no new or different type of equipment will be installed). The changes in methods governing normal plant operation are consistent with the current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

This change adds two notes to the Surveillance which relax the Surveillance Frequency to allow a 4 hour delay in performance of the Surveillance after the associated recirculation loop is in operation and an exemption to the performance of the surveillance until 24 hours after the plant reaches 25% RTP. The margin of safety is not significantly reduced because the proposed changes to the Surveillance Frequency will continue to provide the necessary assurance of Operability of the jet pumps at the earliest opportunity. These changes effectively extend the initial performance of the Surveillance Requirement by 4 or 24 hours. This is considered acceptable since the most common outcome of the performance of a Surveillance is the successful demonstration that the acceptance criteria are satisfied. In addition, these changes provide the benefit of allowing the Surveillance to be postponed until plant conditions exist where the Surveillance can be performed. The safety analysis assumptions will still be maintained, thus no question of safety exists. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_2 Labeled Comment/Discussion for ITS 3.4.2)

The proposed change adjusts the surveillance acceptance criteria from 10% to 20% for individual jet pump diffuser-to-lower plenum differential pressure variations from the established pattern. This is located in the Surveillance that verifies the Operability of the jet pumps. This change corrects an error in Technical Specifications. This change is consistent with the recommendations of SIL-330 (GE Service Information Letter number 330) and NUREG/CR-3052 (Closeout of IE Bulletin 80-07: BWR Jet Pump Assembly Failure). SIL-330 specifies a 10% criteria for individual jet pump flow distribution. When measured by jet pump diffuser-to-lower plenum differential pressure, the equivalent limit is 20% because of the relationship between flow and delta-P. Since PBAPS Units 2 and 3 utilize the diffuser-to-lower plenum differential pressure measurement, the variance allowed should have been 20% as was recommended in SIL-330 and NUREG/CR-3052. Since the value is being changed from 10% to 20%, it is considered a relaxation from existing requirements although the change corrects an error. Therefore, this change constitutes a less restrictive change. This change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change adjusts the jet pump Surveillance acceptance criteria from 10% to 20% for individual jet pump diffuser-to-lower plenum differential pressure variations from the established pattern. This change corrects an error made in the Technical Specifications. The error resulted in PBAPS acceptance criteria being more conservative than required. SIL-330 and NUREG/CR-3052 recommended certain requirements be met for the jet pumps to be Operable. One specified a 10% criteria for individual jet pump flow distribution. When measured by jet pump diffuser-to-lower plenum differential pressure the equivalent limit is 20% because of the relationship between flow and delta-P. Since PBAPS Units 2 and 3 utilize the diffuser-to-lower plenum differential pressure measurement, the variance allowed is being changed to 20% as was recommended in SIL-330 and NUREG/CR-3052. The proposed change does not effect the probability of an accident. The jet pumps are not assumed to be an initiator of any analyzed event. This change increases the variance allowed in a Surveillance acceptance criteria consistent with the recommendations of the SIL and NUREG. Adopting the recommendations of the

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_2 Labeled Comment/Discussion for ITS 3.4.2)

1. (continued)

SIL and NUREG, which are the recommendations to ensure jet pump Operability, will not affect the consequences of an accident since the recommended acceptance criteria still provide adequate assurance the jet pumps are Operable. This change will not alter assumptions relative to the mitigation of an accident or transient event. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

The proposed change adjusts the jet pump Surveillance acceptance criteria from 10% to 20% for individual jet pump diffuser-to-lower plenum differential pressure variations from the established pattern. This change corrects an error in the Technical Specifications. The error resulted in PBAPS acceptance criteria being more conservative than required. The proposed changes to adopt the recommended acceptance criteria will not create the possibility of an accident. This change will not physically alter the plant (no new or different type of equipment will be installed). The changes in methods governing normal plant operation are consistent with the current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

The proposed change adjusts the jet pump Surveillance acceptance criteria from 10% to 20% for individual jet pump diffuser-to-lower plenum differential pressure variations from the established pattern. This change corrects an error in the Technical Specifications. The error resulted in PBAPS acceptance criteria being more conservative than required. The margin of safety is not significantly reduced because the proposed changes to the acceptance criteria will continue to verify jet pump Operability. The changes reflect the recommendations in SIL-330 and NUREG/CR-3052. The safety analysis assumptions will still be maintained, thus no question of safety exists. In addition, this change provides the benefit of avoiding a shutdown transient, when the jet pumps are still capable of performing their safety function. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_3 Labeled Comment/Discussion for ITS 3.4.2)

This change deletes the current shutdown requirement associated with jet pump flow indication. Currently, when required jet pump flow indication is lost, an orderly shutdown must be initiated in 12 hours and the reactor is required to be in Cold Shutdown within the following 24 hours (since Mode 3 is the non-applicable mode, then 24 hours is allowed to reach Mode 3; see discussion of change M_1 for ITS 3.4.2). The proposed Specification implicitly requires the jet pump flow indication to be Operable only for the performance of the Surveillance Requirement. If the flow indication is inoperable when the surveillance is required to be performed, the jet pump would be declared inoperable and the appropriate actions would be followed. Since the proposed jet pump surveillance requirement is required to be performed every 24 hours (the 25% extension per SR 3.0.2 can be applied) and the Required Actions require the reactor to be in Mode 3 within 12 hours, the maximum difference in the current Specification and the proposed specification is 6 hours. As a result, the proposed specification effectively allows a maximum of an additional 6 hours (which is the 25% extension) to reach a non-applicable Mode if a required core flow indicator is inoperable. Depending on when the failure occurs, 6 hours is the maximum increase over the current Specifications (failure occurring immediately after the Surveillance is performed). The following table provides the details of the calculation of the 6 hour period:

Current Tech Specs	Proposed Tech Specs
Time 0 hours - Jet Pump Indication Fails - 12 hr AOT Begins	Time 0 hours - Jet Pump Indication Fails (Immediately After SR)
Time 12 hours- 12 hr AOT Expires - 24 hr AOT Begins to MODE 3 (per 3.0.A; see M_1)	Time 30 hours- (24 hrs x 1.25) SR due; Flow Indication Inop - 12 hr AOT to MODE 3 Begins
Time 36 hours- 24 hr AOT Expires Plant in MODE 3	Time 42 hours- 12 hour AOT Expires Plant in MODE 3

As depicted above, 42 hours is the maximum time that would be allowed if a required jet pump flow indicator is inoperable. Currently a maximum of 36 hours is allowed.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_3 Labeled Comment/Discussion for ITS 3.4.2) - continued

Jet pump flow indication Operability does not directly impact jet pump Operability. Jet pump flow indication is only required to perform the jet pump Surveillance (SR 3.4.2.1). SR 3.4.2.1 verifies jet pump Operability and has a frequency of every 24 hours. The 24 hours Frequency plus the 25% extension has been shown by operating experience to be timely for detecting jet pump degradation and is consistent with the Surveillance Frequency for recirculation loop Operability verification. The most common outcome of the performance of a surveillance is the successful demonstration that the acceptance criteria are satisfied. This change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change deletes the current shutdown requirement associated with jet pump flow indication. However, the proposed jet pump Specification would still require a shutdown if a required jet pump flow indicator failed because the Surveillance Requirement (which proves jet pump Operability) would not be met. Effectively, the proposed Specification would allow a maximum increase of 6 hours to reach Mode 3 if the flow indicator is not made Operable. The proposed change does not effect the probability of an accident. The jet pumps and the jet pump flow indication are not assumed to be an initiator of any analyzed event. The maximum of an additional 6 hours to reach Mode 3 does not impact consequences of an accident. The consequences would be the same in the additional 6 hours as it would be in the first 36 hours. Also, jet pump flow indication Operability does not directly impact jet pump Operability. Jet pump flow indication is only required to perform the jet pump Surveillance (SR 3.4.2.1). SR 3.4.2.1 verifies jet pump Operability and has a frequency of every 24 hours. The 24 hours Frequency plus the 25% extension has been shown by operating experience to be adequate for detecting jet pump degradation and is consistent with the Surveillance Frequency for recirculation loop Operability verification. In addition, the most common outcome of the performance of a surveillance is the successful demonstration that the acceptance criteria are satisfied. This change will not alter assumptions relative to the mitigation of an accident or transient event. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_3 Labeled Comment/Discussion for ITS 3.4.2) - continued

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This change will not create the possibility of an accident. This change deletes the current shutdown requirement associated with jet pump flow indication. However, the proposed jet pump Specification would still require a shutdown if a required jet pump flow indicator failed because the Surveillance Requirement (which proves jet pump Operability) could not be satisfied. Effectively, the proposed Specification would allow a maximum increase of 6 hours to reach Mode 3 if the flow indicator is not made Operable. This proposed change to the allowed outage time will not create the possibility of an accident. This change will not physically alter the plant (no new or different type of equipment will be installed). The changes in methods governing normal plant operation are consistent with the current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change deletes the current shutdown requirement associated with jet pump flow indication. However, the proposed jet pump Specification would still require a shutdown if a required jet pump flow indicator failed because the Surveillance Requirement (which proves jet pump Operability) could not be satisfied. Effectively, the proposed Specification would allow a maximum increase of 6 hours to reach Mode 3 if the flow indicator is not made Operable. The margin of safety is not affected by the proposed change. The outcome of analyzed events are the same with the additional 6 hours allowed to reach Mode 3. Also, jet pump flow indication Operability does not directly impact jet pump Operability. Jet pump flow indication is only required to perform the jet pump Surveillance which verifies jet pump Operability. This change is acceptable since the most common outcome of the performance of a surveillance is the successful demonstration that the acceptance criteria are satisfied. The safety analysis assumptions will still be maintained, thus no question of safety exists. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_4 Labeled Comment/Discussion for ITS 3.4.2)

Current Technical Specification (CTS) 3.6.E.1 states that if it is determined that a jet pump is inoperable, an orderly shutdown shall be initiated and the reactor shall be in a Cold Shutdown within 24 hours. ITS 3.4.2, Jet Pumps, for the Condition of an inoperable jet pump, requires the reactor to be placed in MODE 3 (Hot Shutdown) within 12 hours. Since the ITS shutdown action does not require placing the unit in MODE 4 (Cold Shutdown), the change to the shutdown action has been categorized as a less restrictive change. The change is considered acceptable since the Applicability of CTS 3.6.E, Jet Pumps, is whenever the reactor is in the startup or run modes (mode switch position as defined in CTS 1.0, Definitions). The Applicability of ITS 3.4.2 is MODES 1 and 2, which are equivalent to the run and startup modes, respectively, of the CTS. In the event of a failure to comply with requirements of the LCO, the reactor must be placed in a non-applicable MODE or condition. The ITS change reflects placing the reactor in the first available non-applicable MODE or condition. This change also achieves consistency with CTS 3.0.A. CTS 3.0.A states "Limiting Conditions for Operation and action requirements are applicable during the operational conditions and other states specified for each specification." Since the applicability of the CTS jet pumps limiting condition for operation and action is with the mode switch in startup or run, placing the mode switch in shutdown (MODE 3 in the ITS) results in exiting the jet pump condition of applicability. As a result, any further reduction in MODE or condition (to Cold Shutdown) is not required per CTS 3.0.A. In addition, not requiring the reactor to be placed in Cold Shutdown (mode switch in shutdown and average reactor coolant temperature ≤ 212°F) reduces the potential for an unnecessary shutdown transient and the resultant thermal effects on plant equipment. B

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change does not result in any hardware changes. The change to the shutdown action reflects placing the reactor in a non-applicable Mode. The requirement to place the reactor in Cold Shutdown when a jet pump is inoperable is not assumed to be an initiator of any analyzed event. Jet pumps are not assumed to be initiators of any analyzed event. The proposed change does not allow continuous operation in a Mode where jet pumps are required to be Operable. The proposed change still requires the reactor to be placed in a non-applicable Mode in the event a jet pump

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_4 Labeled Comment/Discussion for ITS 3.4.2)

1. (continued)

is inoperable. In addition, the proposed change requires the reactor to be placed in the non-applicable Mode sooner than the existing shutdown action. The Completion Time of the proposed change is based on the required time to reach the non-applicable Mode in an orderly manner and without challenging plant systems. As a result, the consequences of an event occurring with the proposed change are the same as the consequences of an event occurring with the current shutdown action. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

The proposed change does not involve a physical alteration of the plant (no new or different type of equipment will be installed) or changes in methods governing normal plant operation. The proposed change does not allow continuous operation in a Mode where the jet pumps are required to be Operable. The proposed change still requires the reactor to be placed in a non-applicable Mode in the event a jet pump is inoperable. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated. B

3. Does this change involve a significant reduction in a margin of safety?

No reduction in a margin of safety is involved with this change since the proposed change still requires the reactor to be placed in a non-applicable Mode in the event a jet pump is inoperable. The requirement to place the reactor in Cold Shutdown when a jet pump is inoperable is not an assumption of a design basis accident or transient analysis. The proposed change requires the reactor to be placed in the non-applicable Mode sooner than the existing shutdown action. The Completion Time of the proposed change is based on the required time to reach the non-applicable Mode in an orderly manner and without challenging plant systems. In addition, not requiring the reactor to be placed in Cold Shutdown (mode switch in shutdown and average reactor coolant temperature $\leq$ 212°F) provides a safety benefit by reducing the potential for an unnecessary shutdown transient and the resultant thermal effects on plant equipment. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_1 Labeled Comment/Discussion for ITS 3.4.3)

This proposed change reduces the number of SRVs and SVs to be Operable from 13 to 11. The current requirement requires all 13 SRVs and SVs to be Operable. It specifies an allowed outage time of 30 days if one SRV is inoperable and 7 days if two are inoperable. The proposed specification requires 11 SRVs and SVs to be Operable because the analysis for the worst case accident (closure of all MSIVs with failure of the direct scram associated with MSIV position) shows 11 SRVs and SVs are sufficient to maintain reactor pressure below the ASME Code limit of 110% of design pressure. This change will eliminate the current allowed outage times for one or two SRVs out of service when 13 SRVs are required to be Operable. The proposed change will require with one or more required SRVs or SVs inoperable that the plant be shutdown since this condition represents a loss of function. This is consistent with the current requirement when more than two SRVs are inoperable.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This proposed change reduces the number of SRVs and SVs to be Operable from 13 to 11. The proposed change does not increase the probability of an accident. The number of SRVs required to be Operable is not assumed to be an initiator of any analyzed event. Reducing the number of required SRVs and SVs from 13 to 11 is consistent with the analysis that shows 11 SRVs and SVs are sufficient to maintain reactor pressure below ASME limits. Therefore, the consequences of an accident are not increased. This change will also not alter assumptions relative to the mitigation of an accident or transient event. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This proposed change reduces the number of SRVs and SVs to be Operable from 13 to 11. This proposed change will not create the possibility of an accident. This change will not physically alter the plant (no new or different type of equipment will be installed). The changes in methods

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion for ITS 3.4.3)

2. (continued)

governing normal plant operation are consistent with the current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

This proposed change reduces the number of SRVs and SVs to be Operable from 13 to 11. The margin of safety is not affected. Reducing the number of required SRVs and SVs from 13 to 11 is consistent with the analysis that shows 11 SRVs and SVs are sufficient to maintain reactor pressure below ASME limits. The safety analysis assumptions will still be maintained, thus no question of safety exists. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_2 Labeled Comment/Discussion for ITS 3.4.3)

This change relaxes the shutdown requirement if the Required Actions and the associated Completion Times are not met. The change requires the reactor to be brought to Mode 3 in 12 hours and Mode 4 in 36 hours. The current requirements require reactor pressure to be reduced to below atmospheric pressure in 24 hours (equivalent to cold shutdown, i.e., when the reactor can be vented). The proposed Completion Times are based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. The proposed shutdown requirement brings the plant to a Mode 4 which is below the mode of applicability. 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. The current requirements would require the plant to be depressurized to a condition which is beyond the accident assumptions of when the SRVs and SVs are required to mitigate credible accidents and transients.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change relaxes the shutdown requirement if the Required Actions or the associated Completion Times are not met. The change requires the reactor to be brought to Mode 3 in 12 hours and Mode 4 in 36 hours. The current requirements which requires reactor pressure to be reduced to below atmospheric pressure in 24 hours (equivalent to Cold Shutdown, i.e., when the reactor can be vented). The proposed change will not increase the probability of an accident. The shutdown Completion Times are not assumed to be initiators of any analyzed event. The proposed Completion Times are based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. The proposed shutdown requirement brings the plant to a Mode 4 which is below the Mode of Applicability. 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. The current requirements would require the plant to be depressurized to a condition which is beyond the assumptions of when the SRVs and SVs are required to mitigate credible accidents and transients. Thus, the proposed change

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_2 Labeled Comment/Discussion for ITS 3.4.3)

1. (continued)

does not affect the consequences of any accident. Also, this change allows for a more controlled shutdown, which reduces the possibility of a transient due to shutting down the plant. This change will not alter assumptions relative to the mitigation of an accident or transient event. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

This change will not create the possibility of an accident. This change relaxes the shutdown requirement if the Required Actions and the associated Completion Times are not met. The change requires the reactor to be brought to Mode 3 in 12 hours and Mode 4 in 36 hours. Reactor pressure is currently required to be reduced to below atmospheric pressure in 24 hours (equivalent to Cold Shutdown, i.e., when the reactor can be vented). The additional time allowed to shutdown the plant to a non-applicable Mode will not create the possibility of an accident. This change will not physically alter the plant (no new or different type of equipment will be installed). The changes in methods governing normal plant operation are consistent with the current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

This change relaxes the shutdown requirement if the Required Actions and associated Completion Times are not met. The change requires the reactor to be brought to Mode 3 in 12 hours and Mode 4 in 36 hours. The current requirements require reactor pressure to be reduced to below atmospheric pressure in 24 hours (equivalent to Cold Shutdown, i.e., when the reactor can be vented). The margin of safety is unaffected by this change. The increased time allowed to reach Mode 4 when the SRV and SV LCO is not met is acceptable based on the low probability of an event requiring the inoperable SRVs and SVs. The proposed shutdown requirement brings the plant to Mode 4 which is below the Mode of Applicability. 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. The current requirements would require the plant to be depressurized to a condition which is beyond the assumptions of when the SRVs and SVs are required to

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_2 Labeled Comment/Discussion for ITS 3.4.3)

3. (continued)

mitigate credible accidents and transients. Also, this change allows for a more controlled shutdown, which reduces the possibility of a transient due to shutting down the plant. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_1 Labeled Comment/Discussion For ITS 3.4.4)

Existing Specification 3.6.C.4 requires that the reactor be in Hot Shutdown within 12 hours and Cold Shutdown within the following 24 hours if the specified requirements for RCS leakage are not being met. Proposed LCO 3.4.4, RCS Operational Leakage, Condition A and Condition B (Required Action B.1), provides an additional 4 hours to allow the operators to reduce the leakage (or leakage increase) to within acceptable limits before the a reactor shutdown must be initiated. This additional 4 hours is acceptable because the leakage limits are significantly below the leakage that would constitute a critical crack size. The critical crack size is a crack large enough that it is indicative of crack instability. This change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change will allow an additional 4 hours following the determination that RCS leakage is exceeding specified limits before a reactor shutdown must be initiated. This time is intended to allow the operators to attempt to reduce the leakage (or leakage rate) to within acceptable limits. The probability of an accident is not increased because the amount of time between identification of a leak and the initiation of a reactor shutdown is not considered as an initiator of any accidents previously evaluated. In addition, the proposed change does not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, or tested. The consequences of an accident will not be increased because the additional 4 hours permitted to investigate and correct the source of RCS leakage will not allow a delay in the reactor shutdown if a critical leak exists. 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 shows that leakage rates of hundreds of gallons per minute will precede crack instability. The difference between exceeding the specified RCS leakage limits and a critical crack leak is sufficiently large to allow a time period for corrective action to be taken before the reactor coolant pressure boundary is compromised. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion For ITS 3.4.4) - continued

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This proposed change will not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, tested, or inspected. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   The proposed change will allow an additional 4 hours following the determination that RCS leakage is exceeding specified limits before the a reactor shutdown must be initiated. This time is intended to allow the operators to attempt to reduce the leakage (or leakage rate) to within acceptable limits. RCS leakage limits are intended to provide early indication of RCS boundary cracks that could be precursors to loss of coolant accidents. Following the determination that RCS leakage is exceeding specified limits, the additional 4 hours permitted to investigate and correct the source of RCS leakage will not allow a delay in the reactor shutdown if a critical leak exists. 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 shows that leakage rates of hundreds of gallons per minute will precede crack instability. The difference between exceeding the specified RCS leakage limits and a critical crack leak is sufficiently large to allow a time period for corrective action to be taken before the reactor coolant pressure boundary is compromised. As a result, the change does not affect the current analysis assumptions. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_2 Labeled Comment/Discussion For ITS 3.4.4)

Proposed LCO 3.4.4, RCS Operational Leakage, will add an alternative to existing requirement in Specifications 3.6.C.1 and 3.6.C.4 that a reactor shutdown be initiated if unidentified leakage increases at a rate of more than 2 gpm within a 24 hour period. Under proposed Required Action B.2, unidentified leakage that increases at a rate of more than 2 gpm within a 24 hour period will not require initiation of a reactor shutdown if it can be determined within 4 hours that the source of the unidentified leakage is not service sensitive type 304 and type 316 austenitic stainless steel piping that is subject to high stress or that contains relatively stagnant or intermittent flow fluids. This alternative Required Action is acceptable because the low limit on the rate of increase of unidentified leakage was established as a method for early identification of Intergranular Stress Corrosion Cracking (IGSCC) in type 304 and type 316 austenitic stainless steel piping. IGSCC produces tight cracks and the small flow increase limit is capable of providing an early warning of such deterioration. Verification that the source of leakage is not type 304 and type 316 austenitic stainless steel eliminates IGSCC as a cause of leak. This significantly reduces concerns about crack instability and the rapid failure in the RCS boundary. Also, the unidentified LEAKAGE limit is still being maintained and will continue to limit the maximum unidentified LEAKAGE allowed. This change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change will add an alternative to a reactor shutdown if unidentified leakage increases at a rate of more than 2 gpm within a 24 hour period. A reactor shutdown will not be required if it can be determined within 4 hours that the source of the unidentified RCS leakage is not service sensitive type 304 and type 316 austenitic stainless steel piping and unidentified and total RCS leakage limits are not being exceeded. The probability of an accident is not increased because, if unidentified and total RCS leakage remain within limits, and the source of the leakage is not service sensitive type 304 and type 316 austenitic stainless steel piping, a small increase in the rate of unidentified RCS leakage is not considered as an initiator of any accidents previously evaluated. In addition, the proposed change does not involve any physical changes to plant systems, structures, or components (SSC), or the manner

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_2 Labeled Comment/Discussion For ITS 3.4.4)

1. (continued)

in which these SSC are operated, maintained, modified, or tested. The consequences of an accident will not be increased because the limit on the rate of increase of unidentified leakage was established as a method for early identification of Intergranular Stress Corrosion Cracking (IGSCC) in type 304 and type 316 austenitic stainless steel piping. Verification that the source of leakage is not type 304 and type 316 austenitic stainless steel eliminates IGSCC as a cause of leak and, therefore, the required actions designed to respond to IGSCC are not required. Limits on unidentified and total RCS leakage are still applicable. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

This proposed change will not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, tested, or inspected. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

The proposed change will add an alternative to a reactor shutdown if unidentified leakage increases at a rate of more than 2 gpm within a 24 hour period. A reactor shutdown will not be required if it can be determined within 4 hours that the source of the unidentified RCS leakage is not service sensitive type 304 and type 316 austenitic stainless steel piping and unidentified and total RCS leakage limits are not being exceeded. The margin of safety is not significantly reduced because the limit on the rate of increase of unidentified leakage was established as a method for early identification of Intergranular Stress Corrosion Cracking (IGSCC) in type 304 and type 316 austenitic stainless steel piping. Verification that the source of leakage is not type 304 and type 316 austenitic stainless steel eliminates IGSCC as a cause of leak and, therefore, the required actions designed to respond to IGSCC are not required. Limits on unidentified and total RCS leakage are still applicable. As a result, the change does not affect the current analysis assumptions. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_1 Labeled Comment/Discussion For ITS 3.4.5)

These requirements have been deleted. An instrument check would not consistently demonstrate operability since normally the instruments could not be compared to any other instruments, and their reading could be anywhere on scale. Thus, observing the meter would provide no valid information as to whether the instrument was OPERABLE. The CHANNEL FUNCTIONAL TEST requirement is the best indicator of OPERABILITY while operating, and this requirement is being maintained. This is also consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change deletes the requirement to perform instrument checks on the equipment and floor drain sump flow integrators. This system consists of monitoring instrumentation only and does not initiate any automatic actuations or isolations during any analyzed accident. The leakage detection systems are not considered as initiators of any previously evaluated accident. However, they do provide information to the operator of potential conditions that may be precursors to an accident. the remaining Surveillances will still ensure the instrumentation remains OPERABLE. Therefore, the proposed change will not increase the probability of any accident previously evaluated. Because the leakage detection systems do not provide any accident mitigation functions, the proposed change will not increase the consequences of any accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This proposed change will not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, or inspected. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion For ITS 3.4.5) - continued

3. Does this change involve a significant reduction in a margin of safety?

   The proposed change deletes the requirement to perform instrument checks on the equipment and floor drain sump flow integrators. However, the proposed change still ensures that adequate indications to the operator are maintained. The instruments are still tested and maintained operable, since Channel Functional Tests and Channel Calibrations are still required. In addition, proposed SR 3.4.4.1 will require the use of the equipment or floor drain sump integrators to determine the actual leakage rate every 4 hours. This should minimize the potential for an undetected failure of the integrators. As a result, the change does not affect the current analysis assumptions. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (ontinued)
(L_1 Labeled Comment/Discussion For ITS 3.4.6)

Existing Specification 4.6.B.1 limits the amount of time to 800 hours in any consecutive 12 month period that the reactor may be operated with reactor coolant specific activity Dose Equivalent I-131 greater than > 0.2 μCi/gm. In accordance with the recommendations in Generic Letter 85-19, Reporting Requirements on Primary Coolant Iodine Spikes, proposed LCO 3.4.6 will not include the 800 hour limit. Generic Letter 85-19 states that the 800 hour limit is not necessary because reactor fuel has improved significantly since this requirement was established, and that proper fuel management by licensees and existing reporting requirements for fuel failures will preclude ever approaching this limit of operating with specific activity > 0.2 μCi/gm for more than 800 hours. This change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change eliminates the limit of 800 hours in any consecutive 12 month period that the reactor may be operated with reactor coolant specific activity Dose Equivalent I-131 > 0.2 μCi/gm. Specific activity is not considered an initiator of any accidents previously evaluated. In addition, the proposed change does not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, or tested. The consequences of an accident would be the same when reactor coolant specific activity is above 0.2 microcuries per gram. Therefore, the consequences of an accident are not increased. As discussed in Generic Letter 85-19, reactor fuel has improved significantly since this requirement was established, and proper fuel management by licensees and existing reporting requirements for fuel failures will preclude ever approaching this limit of operating with specific activity > 0.2 μCi/gm for more than 800 hours. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion For ITS 3.4.6) - continued

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This proposed change will not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, tested, or inspected. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   The proposed change does not involve a significant reduction in a margin of safety because, as discussed in Generic Letter 85-19, reactor fuel has improved significantly since this requirement was established, and proper fuel management by licensees and existing reporting requirements for fuel failures will preclude ever approaching this limit of operating with specific activity > 0.2 μCi/gm for more than 800 hours. In addition, the proposed change does not involve any physical changes to plant systems, structures, or components (SSC), or the manner in which these SSC are operated, maintained, modified, or tested. As a result, the change does not affect the current analysis assumptions. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_1 Labeled Comment/Discussion for ITS 3.4.9)

The frequency for verifying that RCS temperature and pressure are within limits has been extended from 15 minutes to 30 minutes. The 30 minute Frequency is considered adequate for maintaining RCS temperature and pressure within limits during planned changes in view of the available control room indication to monitor the RCS status and the fact that RCS heatup and cooldown operations and RCS inservice leak and hydrostatic tests are very controlled evolutions. In addition, industry operating experience has shown this frequency to be adequate for maintaining RCS temperature and pressure limits during planned evolutions. This change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change would decrease the frequency of the RCS temperature and pressure verification so that it is only required to be performed once per 30 minutes instead of once per 15 minutes. The RCS temperature and pressure are not expected to exceed limits during the extended surveillance interval since planned RCS heatup and cooldown operations and RCS inservice leak and hydrostatic tests are very controlled evolutions. Additionally, a failure to perform this surveillance is not identified as the initiator of any analyzed event. Further, since the change impacts only the frequency of the verification and does not result in any change in the actual temperature or pressure limits, consequences of analyzed accidents are unaffected. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This change does involve a physical alteration of the plant (no new or different type of equipment will be installed) or changes in methods governing normal plant operation. The proposed change impacts only the frequency of verification and does not result in any change in the actual temperature or pressure limits. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion for ITS 3.4.9) - continued

3. Does this change involve a significant reduction in a margin of safety?

   The change only impacts the frequency of the RCS temperature and pressure verification. The proposed 30 minute frequency is considered adequate for maintaining operation within limits considering the available control room indicators to monitor RCS status and the fact that planned RCS heatup and cooldown operations and RCS inservice leak and hydrostatic tests are very controlled evolutions. In addition, industry operating experience has shown this frequency is adequate for maintaining RCS temperature and pressure within limits. This change will not alter assumptions relative to the mitigation of an accident or transient event. The change will not alter the operation of process variables, structure, systems, or components as described in the safety analysis. This change does not affect the current safety analysis assumptions. As such, no question of safety exists. Therefore, this change does not involve a significant reduction in a margin of safety.

ENVIRONMENTAL ASSESSMENT
SECTION 3.4--REACTOR COOLANT SYSTEM

This proposed Technical Specification Change has been evaluated against the criteria for and identification of licensing and regulatory actions requiring environmental assessment in accordance with 10 CFR 51.21. It has been determined that the proposed changes meet the criteria for categorical exclusion as provided for under 10 CFR 51.22(c)(9). The following is a discussion of how the proposed Technical Specification Change meets the criteria for categorical exclusion.

10 CFR 51.22 (c)(9): Although the proposed change involves changes to requirements with respect to inspection or surveillance requirements;

(i) the proposed change involves no Significant Hazards Consideration (refer to the No Significant Hazards Consideration section of this Technical Specification Change Request),

(ii) there is no significant change in the types or significant increase in the amounts of any effluents that may be released offsite since the proposed changes do not affect the generation of any radioactive effluents nor do they affect any of the permitted release paths, and

(iii) there is no significant increase in individual or cumulative occupational radiation exposure.

Accordingly, the proposed change meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Based on the aforementioned and pursuant to 10 CFR 51.22(b), no environmental assessment or environmental impact statement need be prepared in connection with issuance of an amendment to the Technical Specifications incorporating the proposed changes of this request.

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, R_4, R_5, and R_6 Labeled Comments/Discussions for ITS 3.5.1)

R_4 (cont'd) and alarms are addressed by plant procedures. Therefore, the requirement for testing the LPCI and CS pump discharge line level switches is being relocated to plant procedures. This change is consistent with NUREG-1433.

R_5 Specifications 3.5.H and 4.5.H, Engineered Safeguards Compartments Cooling and Ventilation, are being relocated to plant procedures. The requirement for testing the compartment coolers was relocated to plant procedures. Details on testing some support systems have been relocated to licensee controlled documents. Relocating requirements for the compartment coolers does not preclude them from being maintained Operable. They are required to be Operable in order for the HPCI, RCIC, LPCI and CS systems to be Operable by the definition of Operability. This change is consistent with NUREG-1433. B

R_6 Existing Surveillance Requirement 4.6.D.4 requires manual operation of each relief valve once per operating cycle. This specification is being replaced by SR 3.5.1.12 which performs a similar test on those relief valves designated as ADS valves and SR 3.4.3.2 which performs the same test on those relief valves that are not designated as ADS valves. Existing Surveillance Requirement 4.6.D.4 contains details about performance of this test. Details pertaining to how this surveillance test is verified is being relocated to the Bases and appropriate plant procedures. This change is consistent with NUREG-1433.

(R_1 Labeled Comments/Discussions for ITS 3.5.2)

R_1 The existing Specifications define what constitutes a subsystem and describe minimum requirements for an OPERABLE flow path. These descriptions of the system are relocated to the Bases.

(R_1, R_2, R_3, and R_4 Labeled Comments/Discussions for ITS 3.5.3)

R_1 The requirement to include automatic restart on low water level signal during a simulated automatic actuation test once per cycle was relocated to the Bases. This test requirement will be included as part of the RCIC actuation test description of the Bases for SR 3.5.3.5. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, and R_4 Labeled Comments/Discussions for ITS 3.5.3) - continued

R_2 The requirement to verify automatic transfer from CST to suppression pool on low CST water level once per cycle was relocated to the Bases. This test requirement will be included as part of the RCIC actuation test description of the Bases for SR 3.5.3.5. This change is consistent with NUREG-1433.

R_3 The requirement to ensure that the piping is full from the discharge valve to the injection valve by venting the RCIC from the high point was relocated to the Bases and appropriate plant procedures. Details on how to perform tests or details of tests are being relocated to licensee controlled documents. This change is consistent with NUREG 1433.

R_4 The requirement for testing the compartment coolers was relocated to plant procedures. Details on testing some support systems have been relocated to licensee controlled documents. Relocating the compartment coolers does not preclude them from being maintained Operable. They are required to be Operable in order for the RCIC pumps to be Operable by the definition of Operability. This change is consistent with NUREG-1433. B

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This proposed change relocates requirements from the Technical Specifications to a licensee controlled document. The licensee controlled document containing the relocated requirements will be maintained using the provisions of 10 CFR 50.59 and is subject to the change control process in the Administrative Controls Section of the Technical Specifications. Since any changes to a licensee controlled document will be evaluated per 10 CFR 50.59, no increase (significant or insignificant) in the probability or consequences of an accident previously evaluated will be allowed. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_4 Labeled Comment/Discussion for ITS 3.6.1.3)

Not used.

B

TECHNICAL CHANGES - LESS RESTRICTIVE

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B

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_1 Labeled Comment/Discussion for ITS 3.6.2.3)
(L_1 Labeled Comment/Discussion for ITS 3.6.2.4)

Not used.

B

NO SIGNIFICANT HAZARDS CONSIDERATIONS
SECTION 3.6--CONTAINMENT SYSTEMS

TECHNICAL CHANGES - LESS RESTRICTIVE

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TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, M_3, M_4, and M_5 Labeled Comments/Discussions for ITS 3.8.4) - continued

M_2 The proposed change adds new Surveillance Requirements to the DC Sources—Operating Specification. These Surveillances are as follows:

- SR 3.8.4.2 - Verify no visible corrosion at battery terminals and connectors, or verify battery connection resistance is within limits once per 92 days. This Surveillance provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.
- SR 3.8.4.3 - Verify battery cells, cell plates, and racks show no visual indication of physical damage or abnormal deterioration that could potentially degrade battery performance once per 12 months. This Surveillance provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance. B
- SR 3.8.4.4 - Remove visible corrosion, and verify battery cell to cell and terminal connections are coated with anti-corrosion material once per 12 months. This Surveillance provides an indication of physical damage or abnormal deterioration that could indicate degraded battery condition.
- SR 3.8.4.5 - Verify battery connection resistance is within limits once per 12 months. This Surveillance provides an indication of physical damage or abnormal deterioration that could indicate degraded battery condition.
- SR 3.8.4.6 - Verify each required battery charger supplies a required number of amps at the required voltage once per 24 months. This Surveillance verifies the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state.

The addition of new requirements constitutes a more restrictive change. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)
(M_1 Labeled Comment/Discussion for ITS 3.8.5)

M_1 A new Specification is being added requiring the DC electric power subsystems, necessary to support the DC electrical power distribution subsystem(s) required by proposed LCO 3.8.8, Distribution Systems—Shutdown," to be OPERABLE. The requirements also include the other unit's DC electrical power subsystems necessary to support the DC electrical power distribution subsystem(s) required by proposed LCO 3.8.8, Distribution Systems—Shutdown." This ensures the DC sources needed to mitigate a design basis accident are available in Modes 4 and 5 and during movement of irradiated fuel assemblies in secondary containment.

(M_1, M_2, M_3, M_4, and M_5 Labeled Comments/Discussions for ITS 3.8.6) B

M_1 This change adds Modes 3, 4, and 5, and whenever moving fuel in the secondary containment to the Modes of Applicability for the battery cell parameters. Currently the batteries are required to be Operable whenever the reactor is critical, or in the Run Mode (Mode 1) or the Startup Mode (Mode 2). The proposed Specification will require the battery cell parameters to be within limits (i.e., batteries Operable) when associated DC electrical power subsystems are required to be Operable which is Modes 1 through 5 and during movement of irradiated fuel in secondary containment. The addition of Mode 3 is required because the reactor has enough energy for postulated accidents to occur and mitigation by the ECCS may be required. The addition of Modes 4 and 5, and whenever moving irradiated fuel in the secondary containment ensures that there is available power to equipment required to mitigate fuel handling accidents, cool the irradiated fuel, and monitoring instruments required to ensure that the unit is maintained in Mode 4 or 5. This change is consistent with NUREG-1433.

M_2 This change proposes to add the acceptance criteria for the Surveillance Requirements in the Technical Specification. This change also adds Table 3.8.6-1 which lists acceptance criteria for Category A and Category B values and Category C limits for float voltage, electrolyte level, and specific gravity (or charging current). The current specifications do not list the acceptance criteria in the Technical Specification. This change is a more restrictive change since any changes to the acceptance criteria will require NRC review and approval versus the current 10 CFR 50.59 review process.

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, M_3, M_4, and M_5 Labeled Comments/Discussions for ITS 3.8.6) - continued

M_3 This change proposes to add Surveillance Requirements to verify the electrolyte level. The proposed change will require a 7 day verification that electrolyte level of the pilot cell is within Category A limits of Table 3.8.6-1. The proposed change will also require a 92 day verification that electrolyte level of each cell is within the Category B limit of Table 3.8.6-1. The electrolyte level Surveillances are consistent with the guidance in IEEE-450. The limits ensure that the plates suffer no physical damage, and that adequate electron transfer capability is maintained in the event of transient conditions. The Frequency is also consistent with IEEE-450. This change is consistent with NUREG-1433.

M_4 This change proposes to add additional Frequencies to SR 3.8.6.2 (Verification of Category B limits of Table 3.8.6-1). The proposed requirement will add an additional requirement to test the battery cells once within 24 hours after battery discharge < 100 V and once within 24 hours after battery overcharge > 145 V. This proposed change is consistent with IEEE-450 which recommends special inspections following a severe discharge or overcharge, to ensure no significant degradation of the battery occurs as a consequence of such discharge or overcharge.

M_5 The requirement specifying cell voltage measurements be performed "to the nearest 0.1 volt" has been made more restrictive as a result of the acceptance criteria of Table 3.8.6-1. Table 3.8.6-1 specifies acceptance criteria for cell voltage of ≥ of 2.13 volts for Category A and B limits and ≥ 2.07 volts for Category C limits. This represents a more restrictive change since, to satisfy cell voltage requirements in Table 3.8.6-1, measurements must be performed to the nearest 0.01 volt.

(M_1, M_2, and M_3 Labeled Comments/Discussions for ITS 3.8.7)

M_1 This change adds Mode 3 to the Modes of Applicability for the distribution systems. Currently, the distribution systems are required to be Operable whenever the reactor is critical or in Mode 1 or 2. The addition of Mode 3 is required because the reactor has enough energy for postulated accidents to occur and mitigation by the ECCS may be required. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, and M_3 Labeled Comments/Discussions for ITS 3.8.7) - continued

M_2 Certain equipment needed to meet Unit 2 accident analysis is powered from the Unit 3 AC and DC Distribution System and certain equipment needed to meet Unit 3 accident analysis is powered from the Unit 2 AC and DC Distribution System. Currently, the distribution buses of the other unit are required since definition of Operability requires the normal and emergency power to be Operable. To make the Technical Specifications more user friendly, the required buses of the other unit have been added, similar to the already required buses. Since the buses of the other unit are now described, the current LCO and Actions for buses have been modified to explicitly use the unit designator for clarity. Actions have also been provided (proposed Actions A and B) to limit the out of service time of a required AC bus from the other unit to 7 days and a required DC bus from the other unit to 12 hours. This is consistent with the maximum current time allowed in the individual system LCOs. These changes, in and of themselves, are administrative only. However, due to the addition of proposed Action F, an inoperable bus on one unit concurrent with an inoperable bus on the other unit could result in an LCO 3.0.3 entry. Currently, this is not required. In addition, the required unit DC distribution systems, which are currently governed by the definition of Operability, have been added. Proposed Action D has been provided to limit the out of service time for a unit DC distribution subsystem to 2 hours, consistent with the guidance of Regulatory Guide 1.93. Another Completion Time (16 hours from discovery of failure to meet LCO 3.8.7.a) is added, as described in comment M_3, to establish a maximum time allowed to meet bus requirements. Also, Surveillance Requirements are now explicitly provided for the Unit 2 and Unit 3 AC and DC buses. Therefore, this change, overall, is considered more restrictive on plant operations.

M_3 The current 24 hour restoration time for Specification 3.9.B.7 has been reduced to 8 hours, consistent with the guidance in Regulatory Guide 1.93 and the BWR Standard Technical Specifications (NUREG-1433). The proposed Completion Time has a limitation in addition to the 8 hour limit. This additional limit establishes a maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If an AC distribution subsystem is inoperable while, for instance, a DC bus is inoperable and subsequently returned Operable, the LCO may already have been not met for up to 8 hours. This situation could lead to a total duration of 10 hours, since initial failure of the LCO, to restore the DC distribution system. Then, an AC distribution subsystem could again

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, and M_3 Labeled Comments/Discussions for ITS 3.8.7)

M_3 (cont'd) become inoperable, and then the DC distribution subsystem restored Operable. This could continue indefinitely. Therefore, to preclude this and place an appropriate restriction on any such unusual situation, the additional Completion Time of "16 hours from discovery of failure to meet LCO 3.8.7.a" is proposed. This additional Completion Time is also applicable to Action D, which is discussed in comment M_2.

(M_1 Labeled Comment/Discussion for ITS 3.8.8)

M_1 A new Specification is being added (including appropriate Actions and Surveillance Requirements) requiring the necessary portions of the Unit 2 and Unit 3 AC and DC Electrical Power Distribution Systems to be Operable to support equipment required to be Operable during Modes 4 and 5 and during movement of irradiated fuel assemblies in secondary containment. This ensures the distribution subsystems necessary to mitigate a design basis accident are available. The addition of new requirements represents a more restrictive change and is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change provides more stringent requirements than previously existed in the Technical Specifications. The more stringent requirements will not result in operation that will increase the probability of initiating an analyzed event. If anything the new requirements may decrease the probability or consequences of an analyzed event by incorporating the more restrictive changes discussed above. The change will not alter assumptions relative to mitigation of an accident or transient event. The more restrictive requirements will not alter the operation of process variables, structures, systems, or components as described in the safety analyses. The change has been confirmed to ensure no previously evaluated accident has been adversely affected. Therefore, the change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   Making existing requirements more restrictive and adding more restrictive requirements to the Technical Specifications will not alter the plant configuration (no new or different type of equipment will be installed) or make changes in methods governing normal plant operation. The change does impose different requirements. However, the change is consistent with assumptions made in the safety analyses. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   Adding new requirements and making existing ones more restrictive either increases or does not affect the margin of safety. The change does not impact any safety analysis assumptions. As such, no question of safety is involved. Therefore, this change will not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, and R_3 Labeled Comments/Discussions for ITS 3.8.4) - continued

R_2 This change will relocate the statement which ties the Actions of the batteries with the ECCS and the DG System. These type of statements will be evaluated in the Safety Function Determination Program and the procedures which implement the program. The Safety Function Determination Program evaluates the relationship between Specifications when equipment is inoperable to ensure a loss of function has not occurred. This change is consistent with NUREG-1433.

R_3 This change will relocate specifics from the Specifications to the Bases. Specifically, this change relocates, to the ITS 3.8.4 Bases: 1) the number of batteries and chargers which are required by the DC Sources—Operating Specification to be Operable; and 2) the interpretation of what once each 60 months means, as it relates to the performance of a discharge test. These changes are consistent with NUREG-1433.

(R_1 Labeled Comment/Discussion for ITS 3.8.6)

R_1 The change will relocate items which are procedural in nature to procedures. These items will be retained in procedures and will require a 10 CFR 50.59 review in order to be changed. This change is consistent with NUREG-1433. B

(R_1 Labeled Comment/Discussion for ITS 3.8.7)

R_1 The details relating to system design and what "Operable" means (e.g., energized) have been relocated to the Bases. In addition, the AC buses listed have been relocated to the Bases. Changes to the Bases will be controlled in accordance with the proposed Bases Control Process in Chapter 5 of the Technical Specifications.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

TECHNICAL CHANGES - MORE RESTRICTIVE

This particular No Significant Hazards Considerations is for the changes labeled "Technical Changes - More Restrictive" for the conversion to NUREG-1433. These changes incorporate more restrictive changes into the current Technical Specifications by either making current requirements more stringent or adding new requirements which currently do not exist. The following is a list of the more restrictive changes.

(M_1, M_2, M_3, M_4, M_5, M_6, M_7, M_8, M_9, M_{10}, M_{11}, M_{12}, and M_{13} Labeled Comment/Discussion for ITS 5.0)

M_1 This change proposes to list the qualifications of the individual, who is designated to be responsible for the control room command function in the absence of the Shift Supervisor. In the current TS, no qualifications are listed for the designated individual. The proposed change will require the designated individual to have an active Senior Reactor Operator (SRO) license in Mode 1, 2, 3, 4, or 5 or an active Reactor Operator (RO) license in Mode 4 or 5. The addition of specific requirements to the Technical Specifications constitutes a more restrictive change. This change is consistent with NUREG-1433.

M_2 This proposed change will add requirements to the qualifications of personnel in the control room during specific times. The current TS require two licensed operators to be in the control room during reactor startups, scheduled reactor shutdowns, and during recovery from reactor trips. The proposed change will require one of the two licensed operators to have an SRO during Modes 1, 2, and 3. Since this requirement will require one of the licensed operators to have an SRO (whereas currently both could have an RO) this is considered a more restrictive change. This change is consistent with NUREG-1433.

M_3 This proposed change will list specific duties of the Shift Technical Advisor in the TS. In the current TS no specific duties are listed for the STA; only that the STA meets the requirements of the 1985 NRC Policy Statement on Engineering Expertise on Shift. The proposed TS will require the STA to meet the requirements of the NRC Policy Statement and will require the STA to provide advisory technical support to the Shift Supervisor in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to safe operation of the unit. This change is consistent with NUREG-1433.

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, M_3, M_4, M_5, M_6, M_7, M_8, M_9, M_{10}, M_{11}, M_{12}, and M_{13} Labeled Comment/Discussion for ITS 5.0) - continued

M_4 This change proposes to add requirements for emergency operating procedures (EOPs) in the TS. The current TS do not specifically require the current form of EOPs (although PBAPS is committed to have them per NUREG-0737 and GL 82-33). The proposed TS will require EOPs which implement the requirements of the NUREG and GL. This change adds new requirements to the TS which constitutes a more restrictive change. This change is consistent with NUREG-1433.

M_5 This change proposes to add the requirement that procedures be established, implemented, and maintained for all programs identified in Specification 5.5 "Programs and Manuals." The addition of the requirement that procedures be established, implemented, and maintained for the programs of Section 5.5 is consistent with the requirement for these programs. The addition of requirements in the TS constitutes a more restrictive change. This change is consistent with NUREG-1433.

M_6 The SGT System filter ΔP limit has been decreased from 8 inches water gauge to 3.9 inches water gauge. This ensures that at the maximum allowed filter train flow rate (10500 cfm allowed per SR 3.6.4.1.4), the filter train ΔP will be limited such that filter train integrity is not compromised. Since the limit has been decreased, this constitutes a more restrictive change.

M_7 Not used.

M_8 This change proposes to add a requirement in the TS for the Safety Function Determination Program. This program is included to support implementation of the support system Operability characteristics of the improved Technical Specifications. The addition of new requirements to the TS constitutes a more restrictive change.

M_9 This change proposes to add a requirement in the TS for Technical Specifications Bases Control Program. This program is provided to specifically delineate the appropriate methods and reviews necessary for a change to the Bases of Technical Specifications.

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, M_3, M_4, M_5, M_6, M_7, M_8, M_9, M_{10}, M_{11}, M_{12}, and M_{13} Labeled Comment/Discussion for ITS 5.0) - continued

M_{10} This change proposes to add a requirement in TS for a Component Cyclic or Transient Limit Program. This program provides controls to track the cyclic and transient occurrences to ensure that components are maintained within the design limits. The addition of programs to the TS, constitutes a more restrictive change. This change is consistent with NUREG-1433.

M_{11} This change proposes to add a requirement in Technical Specifications to establish, implement, and maintain procedures covering Quality Assurance for effluent monitoring. This change will ensure that adequate quality assurance is maintained when monitoring effluents. This change adds additional requirements to Technical Specifications which constitutes a more restrictive change. This change is consistent with NUREG-1433.

M_{12} This change proposes to add a requirement in Technical Specifications for the Plant Manager, or his designee, to approve prior to implementation, each proposed test, experiment or modification to systems or equipment that affect nuclear safety. This change ensures the Plant Manager, or his designee, is aware of all changes with the potential to affect nuclear safety. This change adds additional requirements to Technical Specifications which constitute a more restrictive change. This change is consistent with NUREG-1433.

M_{13} The current Specifications utilize the ASTM D4176-82 clear and bright test to provide a qualitative assessment of the acceptability of new diesel fuel oil with regard to water and sediment content. The ASTM clear and bright test is a visual check for evidence of water and particulate contamination performed after drawing a fuel oil sample for field testing. The visual check is accomplished by swirling the sample so a vortex is formed. Sediment and water will accumulate on the bottom of the container directly beneath the vortex and very fine suspended solids or water will render the product hazy. The ASTM clear and bright test should only be used for fuel oil meeting the color requirements of ASTM D4176-82 (ASTM color of 5 or less). ASTM D4176-82 does not recommend the clear and bright test be performed on fuels darker than ASTM 5 since the presence of free water or particulates could be obscured. The intentional addition of dyes to fuel oil by suppliers (such as to identify sulfur content) makes the fuel oil darker than ASTM 5 and results in the need to use another method for determining water and

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, M_3, M_4, M_5, M_6, M_7, M_8, M_9, M_{10}, M_{11}, M_{12}, and M_{13} Labeled Comment/Discussion for ITS 5.0)

M_{13} (cont'd) sediment content of the fuel oil. To address the method for determining the presence of water and sediment in new diesel fuel oil that has been dyed, the requirements of Specification 5.5.9 (Diesel Fuel Oil Testing Program) and the Bases for SR 3.8.3.3 are proposed to be revised to allow the use of the ASTM D975-81 water and sediment by centrifuge test in lieu of the ASTM D4176-82 clear and bright test. The Bases for SR 3.8.3.3 will also be revised to reflect the use of the ASTM water and sediment by centrifuge test when dyes have intentionally been added to new fuel oil.

This change provides an alternate test for verifying the acceptability of new fuel oil with regard to water and sediment content. Excessive water and sediment in diesel fuel oil could have an immediate detrimental impact on diesel engine combustion and as a result diesel generator OPERABILITY. The ASTM D975-81 water and sediment by centrifuge test provides a quantitative assessment of water and sediment content. The use of the ASTM water and sediment by centrifuge test ensures that excessive water and sediment content, in new diesel fuel oil that has been dyed, will be detected (and not obscured by the presence of the dye) prior to addition to the storage tanks. The sensitivity of the ASTM water and sediment by centrifuge test for water and sediment is not affected by the presence of dyes in the fuel oil. For fuel oil with dyes, the sensitivity for detection of water and sediment of the ASTM water and sediment by centrifuge test is better than that provided by the ASTM clear and bright test. The ASTM water and sediment by centrifuge test is also the same test performed to quantitatively determine water and sediment content within 31 days following sampling and addition (after the new fuel has been added to the storage tank) in accordance with Specification 5.5.9.b and the Bases for SR 3.8.3.3. Regulatory Guide 1.137, Fuel Oil Systems for Standby Diesel Generators, also identifies that the water and sediment by centrifuge test provides an acceptable method for ensuring the initial and continuing quality of diesel fuel oil with respect to water and sediment content. Therefore, this alternate test provides adequate assurance, prior to storage tank addition, that the water and sediment content of the new dyed fuel oil will maintain diesel generator OPERABILITY. This change is considered to be more restrictive since the ASTM water and sediment by centrifuge test provides a quantitative assessment of water and sediment content rather than the qualitative assessment of water and sediment

TECHNICAL CHANGES - MORE RESTRICTIVE
(M_1, M_2, M_3, M_4, M_5, M_6, M_7, M_8, M_9, M_{10}, M_{11}, M_{12}, and M_{13} Labeled Comment/Discussion for ITS 5.0) B

M_{13} (cont'd) content provided by the ASTM clear and bright test. In addition, the ASTM water and sediment by centrifuge test takes more time to perform and is more difficult to perform than the ASTM clear and bright test. However, as previously discussed, this change is necessary to assure the presence of dyes in fuel oil will not affect the capability to detect water and sediment in the fuel oil. B

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change provides more stringent requirements than previously existed in the Technical Specifications. The more stringent requirements will not result in operation that will increase the probability of initiating an analyzed event. If anything the new requirements may decrease the probability or consequences of an analyzed event by incorporating the more restrictive changes discussed above. The change will not alter assumptions relative to mitigation of an accident or transient event. The more restrictive requirements will not alter the operation of process variables, structures, systems, or components as described in the safety analyses. The change has been confirmed to ensure no previously evaluated accident has been adversely affected. Therefore, the change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   Making existing requirements more restrictive and adding more restrictive requirements to the Technical Specifications will not alter the plant configuration (no new or different type of equipment will be installed) or changes in methods governing normal plant operation. The change does impose different requirements. However, the change is consistent with assumptions made in the safety analyses. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

3. Does this change involve a significant reduction in a margin of safety?

Adding new requirements and making existing ones more restrictive either increases or does not affect the margin of safety. The change does not impact any safety analysis assumptions. As such, no question of safety is involved. Therefore, this change will not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - RELOCATIONS

This proposed change relocates requirements from the Technical Specifications to a licensee controlled document. These changes are labeled "Technical Changes - Relocations." These changes are listed below.

(R_1, R_2, R_3, R_4, R_5, R_6, R_7, R_8, R_9, R_{10}, R_{11}, R_{12}, R_{13}, R_{14}, R_{15}, R_{16}, and R_{17} Labeled Comment/Discussion for ITS 5.0)

R_1 PECO Energy proposes the Minimum Shift Crew Composition Table not be retained in Technical Specifications. 10 CFR 50.54(k), (l), and (m) provide the requirements for the shift complement regarding licensed operators. The regulations describe the minimum shift composition for operating modes, as well as cold shutdown and refueling. Additionally, Specifications 5.1.2 and 5.2.2.c of the Improved Technical Specifications specify the conditions when the licensed operator is required to be in the control room. Non-licensed operator requirements will be maintained in Specification 5.2.2.a. Removing the Table from Technical Specifications will not jeopardize plant safety nor is it necessary to be duplicated in order to assure safe operation of the facility. These requirements will also be included in plant procedures.

R_2 PECO Energy proposes the requirement for an SRO to be present during fuel handling and to supervise all core alternations not be retained in Technical Specifications. Duplication of the regulation provided in 10 CFR 50.54(m)(2)(iv) is not necessary to assure safe operation of the facility. The current regulation states,

> "Each licensee shall have present, during alteration of the core of a nuclear power unit (including fuel loading or transfer), a person holding a senior operator license or a senior operator license limited to fuel handling to directly supervise the activity and, during this time, the licensee shall not assign other duties to this person."

R_3 Technical Specifications need not require an administrative letter to be issued to station personnel on an annual basis describing the responsibility of the Shift Supervisor. The organization and responsibilities of each function are adequately described in the UFSAR. As a result, this requirement may be relocated to the UFSAR or appropriate plant procedures. Plant safety is not compromised by this proposed change.

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, R_4, R_5, R_6, R_7, R_8, R_9, R_{10}, R_{11}, R_{12}, R_{13}, R_{14}, R_{15}, R_{16}, and R_{17} Labeled Comment/Discussion for ITS 5.0) - continued

R_4 PECO Energy proposes that the review and audit functions, ISEG requirements, Reportable Event internal review requirements, requirements for procedures that meet ANSI N18.7-1972, the requirement that procedures covering Quality Assurance for environmental monitoring use the guidance in Regulatory Guide 4.1, Revision 1, and the Fire Protection Inspections (performed under the audit function of the NRB) be relocated from Technical Specifications on the basis that they can be adequately addressed elsewhere and that there is adequate regulatory authority to do so. Thus, the provisions are not necessary to assure safe operation of the facility, given the existence of these redundant requirements. This proposal would rely on a Quality Assurance Program implementing 10 CFR 50.54 and 10 CFR 50, Appendix B, the UFSAR, or appropriate procedures to control the requirements. Such an approach would result in an equivalent level of regulatory authority while providing for a more appropriate change control process. The level of safety of facility operation is unaffected by the change and NRC and PECO Energy resources associated with processing license amendments for these Administrative Control requirements will be optimized. The following points summarize PECO Energy's position on removing these requirements from Technical Specifications.

The on-site review function, composition, alternate membership, meeting frequency, quorum, responsibilities, authority, and records are all covered in equivalent detail in ANSI N18.7-1972. These requirements are also proposed to be covered in the QA Program, UFSAR, or appropriate procedures and equivalent change control is provided by 10 CFR 50.54(a) or 10 CFR 50.59.

The off-site review group is also addressed, although with less detail, in ANSI N18.7-1972. The QA Program, UFSAR, or appropriate procedures will include the requirements for the off-site review group. Since the offsite review group provides after-the-fact recommendations to improve activities, this organization is not necessary to assure safe operation of the facility. Based upon these considerations, duplication of these requirements in the Technical Specifications is unnecessary.

Audit requirements are specified in the QA Program to satisfy 10 CFR 50, Appendix B, Criterion XVIII. Audit requirements are also covered by ANSI N18.7, ANSI N45.2, 10 CFR 50.54(t), 10 CFR 50.54(p), and 10 CFR 73. Therefore, duplication of the requirements contained

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, R_4, R_5, R_6, R_7, R_8, R_9, R_{10}, R_{11}, R_{12}, R_{13}, R_{14}, R_{15}, R_{16}, and R_{17} Labeled Comment/Discussion for ITS 5.0)

R_4 (cont'd) in the above documents in the Administrative Controls Section of the Technical Specifications does not enhance the level of nuclear safety for the unit. Therefore, the provisions relating to audits are not necessary to assure safe operation of the facility.

Relocating ISEG requirements, Reportable Event internal review requirements, requirements for procedures that meet ANSI N18.7-1972, the requirement that procedures covering Quality Assurance for environmental monitoring use the guidance in Regulatory Guide 4.1, Revision 1, and the Fire Protection Inspections requirements to the QA Program or the UFSAR will ensure these requirements are appropriately maintained. The change control process of 10 CFR 50.54(a) for the QA Program or 10 CFR 50.59 for the UFSAR will provide equivalent change control.

R_5 PECO Energy proposes the requirements on training may be deleted from Technical Specifications on the basis that they are adequately addressed by other Section 5.0 administrative controls as well as regulations. Improved Technical Specification Section 5.3, Unit Staff Qualifications, provides adequate requirements to assure an acceptable, competent operating staff. Each member of the unit staff shall meet or exceed the minimum qualifications of specific Regulatory Guides or ANSI Standards acceptable to the NRC staff. Section 5.3 of the Improved Technical Specifications describes the details of the required qualifications.

Additionally, Improved Technical Specification Section 5.2, Organization, details unit staff requirements. Section 5.2.2.a and 5.2.2.b, and 10 CFR 50.54 describe the minimum shift crew composition and delineates which positions require an RO or SRO license. Training and requalification of those positions are as specified in 10 CFR 55.

Based upon these considerations, duplicating the provisions relating to training is not necessary to assure operation of the facility in a safe manner and may be relocated to a licensee controlled document.

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, R_4, R_5, R_6, R_7, R_8, R_9, R_{10}, R_{11}, R_{12}, R_{13}, R_{14}, R_{15}, R_{16}, and R_{17} Labeled Comment/Discussion for ITS 5.0) - continued

R_6 This change proposes to relocate the requirements for the Loss of Shutdown Margin Report, the Reactor Vessel Inservice Inspection Report, the Seismic Monitoring Instrumentation Inoperability Report, the Primary Containment Leak Rate Testing Report, the Sealed Source Leakage Report, and information contained in the Bases for Post Accident Sampling to plant procedures or another licensee controlled document (e.g., UFSAR). Any changes to these requirements will require a 10 CFR 50.59 evaluation. This change is consistent with NUREG-1433.

R_7 This change proposes to relocate the requirements for Reportable Event Action out of TS. These requirements are duplicated in 10 CFR 50.73. These requirements will be relocated to plant procedures or other licensee controlled documents. The NRC and Industry have agreed to remove requirements from the Administrative Controls Section which are duplicated in other regulatory requirements. This change is consistent with NUREG-1433.

R_8 This change proposes to relocate the requirements which state where to send NRC Reports, Program Revisions, etc., out of TS. These requirements will be relocated to plant procedures or other licensee controlled documents. These requirements are duplicated in 10 CFR 50.4. The NRC and Industry have agreed to remove requirements from the Administrative Controls Section which are duplicated in other regulatory requirements. This change is consistent with NUREG-1433.

R_9 This change proposes to relocate the requirements for solid waste reporting requirements to the Process Control Program (PCP). The PCP is described in appropriate plant procedures. These items are relocated to the PCP per GL 89-01 which allowed RETS to be relocated from TS. The PCP implements the requirements of 10 CFR 20, 10 CFR 61, and 10 CFR 71. For more details reference change L_1 for CTS 3/4.8, "Radioactive Materials." This change is consistent with NUREG-1433.

R_{10} This change proposes to relocate the requirements for the Radiation Protection Program and the Iodine Monitoring Program out of Technical Specifications. When evaluating these programs, PECO Energy relied upon a focussed interpretation of the terminology "operation of the facility in a safe manner" for determining whether a program need be retained in the Technical Specifications. PECO Energy interpreted this phrase to mean provisions necessary to

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, R_4, R_5, R_6, R_7, R_8, R_9, R_{10}, R_{11}, R_{12}, R_{13}, R_{14}, R_{15}, R_{16}, and R_{17} Labeled Comment/Discussion for ITS 5.0)

R_{10} (cont'd) ensure reactor safety. In other words, safe manner was assessed relative to nuclear safety. Such an interpretation is consistent with previous regulatory interpretations; most recently, the Commissions Final Policy Statement on Technical Specification Improvement. The Policy Statement, in part, defined the criteria for determining what is necessary to be included within the scope of Technical Specifications. From the Summary of the Policy Statement:

> "The Policy Statement identifies four criteria for defining the scope of Technical Specifications. The criteria were intended to be consistent with the scope of Technical Specifications as stated in the Statement of Consideration accompanying the current rule, 10 CFR 50.36. The Statement of Consideration for the final rule issuing 10 CFR 50.36 (33 FR 18610, December 17, 1968) discusses the scope of Technical Specifications as including the following:
>
> "In the revised system, emphasis is placed on two general classes of technical matters: (1) those related to prevention of accidents, and (2) those related to mitigation of the consequences of accidents. By systematic analysis and evaluation of a particular facility, each applicant is required to identify at the construction permit stage, those items that are directly related to maintaining the integrity of the physical barriers designed to contain radioactivity. Such items are expected to be the subjects of Technical Specifications in the operating license.""

The Summary Statement for the Policy Statement continues:

> "Since many of the requirements are of immediate concern to the health and safety of the public, (the principal operative standard in Section 182a. of the Atomic Energy Act) this Policy Statement adopts, for the purpose of relocating requirements from Technical Specifications to the licensee-controlled documents, the subjective statement of the purpose of Technical Specifications expressed by the Atomic Safety and Licensing Appeal Board in Portland General Electric Company (Trojan Nuclear Plant), ALAB-531, 9 NRC 263 (1979). There, the Appeal Board interpreted Technical Specifications as being reserved for those conditions or limitations upon reactor operation necessary to obviate the possibility of an abnormal situation or event giving rise to an immediate threat to the public health and safety."

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, R_4, R_5, R_6, R_7, R_8, R_9, R_{10}, R_{11}, R_{12}, R_{13}, R_{14}, R_{15}, R_{16}, and R_{17} Labeled Comment/Discussion for ITS 5.0)

R_{10} (cont'd)

The preceding interpretation was provided by the NRC to more clearly define the scope of Technical Specifications, in particular, with respect to limiting conditions for operation (10 CFR 50.36(c)(2)). The wording of 10 CFR 50.36 (c)(2) once again focusses on equipment "required for safe operation of the facility." Thus, defining this same phrase within the context of 10 CFR 50.36(c)(5) in a similar manner would appear to be consistent and appropriate.

The following is the individual evaluation of the programs to be relocated.

* Radiation Protection Program

The Radiation Protection Program (6.11) requires procedures to be prepared for personnel radiation protection consistent with the requirements of 10 CFR 20. These procedures are developed to ensure nuclear plant personnel safety and have no impact on nuclear safety. Additionally, nuclear plant personnel are not 'members of the public.' Thus, the principal operative standard in Section 182a. of the Atomic Energy Act; 'health and safety of the public' does not apply. Based on these considerations, the Radiation Protection Program administrative control is not necessary to assure operation of the facility in a safe manner and can be relocated from Technical Specifications to the UFSAR. The requirement to have procedures to implement Part 20 is also contained within 10 CFR 20.1101(b). Periodic review of these procedures is addressed under 10 CFR 20.1101(c).

* Iodine Monitoring Program

The Iodine Monitoring Program provides controls to ensure the capability to accurately determine the airborne iodine concentration in vital areas under accident conditions. This program was developed to minimize radiation exposure to plant personnel post-accident and has no impact on nuclear safety. Additionally, nuclear plant personnel are not 'members of the public.' Thus, the principal operative standard in Section 182a. of the Atomic Energy Act; 'health and safety of the public' does not apply. Based on these considerations, the Iodine Monitoring Program administrative control is not necessary to assure operation of the facility in a safe manner and can be relocated from Technical Specifications to the UFSAR.

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, R_4, R_5, R_6, R_7, R_8, R_9, R_{10}, R_{11}, R_{12}, R_{13}, R_{14}, R_{15}, R_{16}, and R_{17} Labeled Comment/Discussion for ITS 5.0) - continued

R_{11} PECO Energy proposes to address the review and approval process and the temporary change process for procedures as part of the QA Program, UFSAR, or appropriate procedures. This proposal is based on the existence of the following requirements which are duplicative of 10 CFR 50.36 in these areas and which assure operation of the facility in a safe manner. The requirement for procedures is mandated by 10 CFR 50, Appendix B, Criterion II (second sentence) and Criterion V. ANSI N18.7-1972, which is an NRC staff-endorsed document used in the development of the QA Program, also contains specific requirements related to procedures.

ANSI N18.7-1972, Section 5.2.2 discusses procedure adherence. This section clearly states that procedures shall be followed, and the requirements for use of procedures shall be prescribed in writing. ANSI N18.7-1972 also discusses temporary changes to procedures, and requires review and approval of procedures to be defined.

ANSI N18.7-1972, Section 5.2.15 describes the review, approval and control of procedures. The section describes the requirements for the licensee's Quality Assurance Program to provide measures to control and coordinate the approval and issuance of documents, including changes thereto, which prescribe all activities affecting quality. The section further states that each procedure shall be reviewed and approved prior to initial use. The reviews required are also described.

ANSI N45.2-1971, Section 6 also requires the Quality Assurance Program to describe procedure requirements.

PECO Energy can continue to implement the requirements of 10 CFR 50, Appendix B, regarding procedures without duplicating the necessity of procedure requirements in the facility Technical Specifications. Safe operation of the plant will continue to be maintained, and therefore, the requirements for procedures and their control should not be re-addressed in Technical Specifications. Duplication of the provisions related to procedures is not necessary to assure safe operation of the facility.

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, R_4, R_5, R_6, R_7, R_8, R_9, R_{10}, R_{11}, R_{12}, R_{13}, R_{14}, R_{15}, R_{16}, and R_{17} Labeled Comment/Discussion for ITS 5.0) - continued

R_{12} The requirement to submit a Startup Report has been relocated from the PBAPS TS. The report is a summary of plant startup and power escalation testing following receipt of the Operating License, increase in licensed power level, installation of nuclear fuel with a different design or manufacturer than the current fuel, and modifications that may have significantly altered the nuclear, thermal, or hydraulic performance of the unit. The report provided a mechanism for NRC to review the appropriateness of licensee activities after-the-fact, but provided no regulatory authority once the report was submitted (i.e., no requirement for Commission approval). The approved 10 CFR 50, Appendix B, Quality Assurance Program and Startup Test Program provide assurance the listed activities are adequately performed and that appropriate corrective actions, if required, are taken.

Given that the report was required to be provided to the Commission no sooner than 90 days following completion of the respective milestone, report completion and submittal was clearly not necessary to assure operation of the facility in a safe manner for the interval between completion of the startup testing and submittal of the report. Additionally, given there is no requirement for the Commission to approve the report, then the Startup Report is not necessary to assure operation of the facility in a safe manner.

Based on these considerations, the Startup Report may be removed from Technical Specifications and relocated to a licensee controlled document.

R_{13} This change proposes to relocate the requirements for major changes to the Radioactive Waste Treatment Systems, the Radiation Dose Assessment Report, and specific details for the Radiological Environmental Operating Report and the Radioactive Effluent Release Report, as well as the submittal requirements for these reports and programs, to the Offsite Dose Calculations Manual (ODCM). These items are relocated to ODCM per GL 89-01 which allowed Radiological Effluent Technical Specifications to be relocated from TS. For more details reference change L_1 for CTS 3/4.8, "Radioactive Materials." This change is consistent with NUREG-1433.

R_{14} PECO Energy proposes the requirements on record retention may be deleted from Technical Specifications on the basis that they can be adequately addressed by the QA Program (10 CFR 50, Appendix B, Criterion XVII) and because provisions relating to record keeping do not assure operation of the facility in a safe manner.

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, R_4, R_5, R_6, R_7, R_8, R_9, R_{10}, R_{11}, R_{12}, R_{13}, R_{14}, R_{15}, R_{16}, and R_{17} Labeled Comment/Discussion for ITS 5.0)

R_{14} (cont'd) Facility operations are performed in accordance with approved written procedures. Areas include normal startup, operation and shutdown, abnormal conditions and emergencies, refueling, safety-related maintenance, surveillance and testing, and radiation control. Facility records document appropriate station operations and activities. Retention of these records provides document retrievability for review of compliance with requirements and regulations. Post-compliance review of records does not assure operation of the facility in a safe manner as activities described in these documents have already been performed. Numerous other regulations such as 10 CFR 20, Subpart L, and 10 CFR 50.71 also require the retention of certain records related to operation of the nuclear plant.

R_{15} Existing Specification 4.9.A.1.2.d and 4.9.A.1.2.e identify the requirements for testing new and stored diesel fuel oil. Proposed Specification 3.8.3, Diesel Fuel Oil, Lube Oil, and Starting Air, requires that diesel fuel be tested in accordance with proposed Specification 5.5.9, Diesel Fuel Oil Testing Program, which lists the diesel fuel oil tests required and the applicable ASTM Standards. Descriptions of test performance and acceptance criteria for the required fuel oil tests that are contained in the ASTM Standards are no longer listed in the Technical Specifications but have been relocated to the Bases of proposed Specification 3.8.3 and to plant procedures. Placing these details in the Bases and plant procedures, and the addition of the referenced ASTM Standards of the Diesel Fuel Oil Testing Program in Technical Specifications, provides assurance they will be maintained. Changes to the Bases and plant procedures are controlled so that the information will not be changed without a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_{16} Existing Specification 3.8.C.6 identifies the requirements for monitoring explosive gas downstream of the Off-Gas Recombiners. Proposed Specification 5.5.8, Explosive Gas Monitoring Program, will require that explosive gas concentration limits and a surveillance program for these limits be maintained. However, specific details regarding the explosive gas concentration limits and associated surveillance program are being relocated to plant procedures. Placing these details in the plant procedures, and the addition of

TECHNICAL CHANGES - RELOCATIONS
(R_1, R_2, R_3, R_4, R_5, R_6, R_7, R_8, R_9, R_{10}, R_{11}, R_{12}, R_{13}, R_{14}, R_{15}, R_{16}, and R_{17} Labeled Comment/Discussion for ITS 5.0)

R_{16} (cont'd) the Explosive Gas Monitoring Program to Technical Specifications provides assurance they will be maintained. Changes to the plant procedures are controlled so that the information will not be changed without a 10 CFR 50.59 review. This change is consistent with NUREG-1433.

R_{17} Existing Specification 6.9.1.c requires that all challenges to the primary coolant system safety and relief valves be reported to the NRC on an annual basis. This requirement is being relocated to plant procedures. The report provides a mechanism for the NRC to obtain information regarding challenges to safety and relief valves after-the-fact, but provides no regulatory authority once the report is submitted (i.e., no requirement for NRC approval). Given that the report is only required to be provided annually to the NRC and is not required to be approved by the NRC, it is clearly not necessary to assure operation of the facility in a safe manner.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This proposed change relocates requirements from the Technical Specifications to a licensee controlled document. The licensee controlled document containing the relocated requirements will be maintained using the provisions of 10 CFR 50.59 and any additional change process invoked by the requirement for the specific licensee controlled documents. Since any changes to a licensee controlled document will be evaluated per 10 CFR 50.59 and any additional change control process invoked by the requirement for the specific licensee controlled document, no increase (significant or insignificant) in the probability or consequences of an accident previously evaluated will be allowed. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - RELOCATIONS (continued)

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This change relocates requirements to a licensee controlled document. This change will not alter the plant configuration (no new or different type of equipment will be installed) or changes in methods governing normal plant operation. This change will not impose different requirements and adequate control of information will be maintained. This change will not alter assumptions made in the safety analysis and licensing basis. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change relocates requirements from the Technical Specifications to a licensee controlled document. This change will not reduce a margin of safety since it has no impact on any safety analysis assumptions. In addition, the requirements to be transposed from the Technical Specifications to the licensee controlled document are the same as the existing Technical Specifications. Since any future changes to this licensee controlled document will be evaluated per the requirements of 10 CFR 50.59 and any additional change control process invoked by the requirements for the specific licensee controlled documents, no reduction (significant or insignificant) in a margin of safety will be allowed. Therefore, this change will not involve a significant reduction in a margin of safety.

   The existing requirement for NRC review and approval of revisions, in accordance with 10 CFR 50.90, to these details and requirements proposed for relocation, does not have a specific margin of safety upon which to evaluate. However, since the proposed change is consistent with the BWR Standard Technical Specifications (NUREG-1433 approved by the NRC Staff) and the change controls for proposed relocated details and requirements provide an equivalent level of regulatory authority, revising the Technical Specifications to reflect the approved level of detail and requirements ensures no significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion for ITS 5.0)

This change proposes to relax the requirement to have an individual qualified in radiation protection procedures to be onsite when fuel is in the reactor. The proposed change will allow the position to be vacant for up to two hours in order to provide for unexpected absence, provided immediate action is taken to fill the required position. This change will not have any impact on plant safety because the presence of a person qualified in radiation protection procedures is not required for the mitigation of any accident. The only impact may be if entries into radiation areas are required to repair equipment. However, this impact will be slight because the allowed outage time of equipment is usually longer than 2 hours, the chance of a problem occurring within the 2 hour period this position is unfilled is small, and the probability that the position will be unfilled (since usually more than one person qualified in radiation protection procedures is located on site) is small. This change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change proposes to relax the requirement to have an individual qualified in radiation protection procedures to be onsite when fuel is in the reactor. The proposed change will allow the position to be vacant for up to two hours in order to provide for unexpected absence. The proposed change does not affect the probability of an accident. The actions of an individual qualified in radiation protection procedures are not assumed to be an initiator of any analyzed event. Also, the consequences of an accident are not affected by the presence of an individual qualified in radiation protection. This proposed change does not impact the assumptions of any design basis accident. This change will not alter assumptions relative to the mitigation of an accident or transient event. This change will not have any impact on the plant safety because the presence of a person qualified in radiation protection is not required for the mitigation of any accident. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_1 Labeled Comment/Discussion for ITS 5.0) - continued

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This change proposes to relax the requirement to have an individual qualified in radiation protection procedures to be onsite when fuel is in the reactor. The proposed change will allow the position to be vacant for up to two hours in order to provide for unexpected absence. The proposed change will not create the possibility of an accident. This change will not physically alter the plant (no new or different type of equipment will be installed). The changes in methods governing normal plant operation are consistent with the current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change proposes to relax the requirement to have an individual qualified in radiation protection procedures to be onsite when fuel is in the reactor. The proposed change will allow the position to be vacant for up to two hours in order to provide for unexpected absence. The margin of safety is not affected by the presence or absence on site of an individual qualified in radiation protection procedures. This proposed change has no effect on the assumptions of the design basis accident. This change will not have any impact on the plant safety because the presence of a person qualified in radiation protection is not required for the mitigation of any accident. The safety analysis assumptions will still be maintained, thus no question of safety exists. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_2 Labeled Comment/Discussion for ITS 5.0)

This change proposes to relax the requirement for submitting the Occupational Exposure Report. The current TS require the report to be submitted by March 1 of each year. This proposed change will allow the report to be submitted by March 31 of each year. Given that the report is still required to be provided to the NRC on or before March 31 and covers the previous calendar year, report completion and submittal is clearly not necessary to assure operation in a safe manner for the interval between March 1 and March 31. Additionally, there is no requirement for the NRC to approve the report. Therefore, this change has no impact on the safe operation of the plant. This change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change proposes to relax the requirement for submitting the Occupational Exposure Report. The current TS require the report to be submitted by March 1 of each year. This proposed change will allow the report to be submitted by March 31 of each year. The proposed change does not affect the probability of an accident. The submittal date of the Occupational Exposure Report is not assumed to be an initiator of any analyzed event. Also, the consequences of an accident are not affected by the submittal date of the Occupational Exposure Report. This proposed change does not impact the assumptions of any design basis accident. This change will not alter assumptions relative to the mitigation of an accident or transient event. This change has no impact on the safe operation of the plant. The report will still be required to be submitted each year and does not affect any plant equipment or requirements for maintaining plant equipment. The submittal date of this report is not required for the mitigation of any accident. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

<u>TECHNICAL CHANGES - LESS RESTRICTIVE</u>
(L_2 Labeled Comment/Discussion for ITS 5.0) - continued

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This change proposes to relax the requirement for submitting the Occupational Exposure Report. The current TS require the report to be submitted by March 1 of each year. This proposed change will allow the report to be submitted by March 31 of each year. The proposed change will not create the possibility of an accident. This change will not physically alter the plant (no new or different type of equipment will be installed). The changes in methods governing normal plant operation are consistent with the current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change proposes to relax the requirement for submitting the Occupational Exposure Report. The current TS require the report to be submitted by March 1 of each year. This proposed change will allow the report to be submitted by March 31 of each year. The margin of safety is not reduced by allowing the report to be submitted 30 days later. This proposed change has no effect on the assumptions of the design basis accident. This change has no impact on the safe operation of the plant. The report will still be required to be submitted each year and does not affect any plant equipment or requirements for maintaining plant equipment. The safety analysis assumptions will still be maintained, thus no question of safety exists. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_3 Labeled Comment/Discussion for ITS 5.0)

The requirements of 10 CFR 50.55a(g) currently require inservice testing of the PBAPS ASME Code Class 1, 2, and 3 pumps and valves. NRC Generic Letter 89-04 states that if these pumps are within the Required Action range or the valves exceed the limiting full stroke time value, the associated component must be declared inoperable and the applicable Technical Specification Actions entered. Inservice Testing Program requirements are addressed in Improved Technical Specifications consistent with this philosophy. This change proposes to apply SR 3.0.2 (allowing an extension of 1.25 times the Surveillance interval) and SR 3.0.3 (allowing 24 hours to perform the Surveillance if missed) to the Inservice Testing frequencies. Currently, the requirements of SR 3.0.2 and SR 3.0.3 are not utilized in the Inservice Test Program test frequencies. The change also adds a requirement that the ASME Boiler and Pressure Vessel Code requirements will not supersede the requirements of any TS. The 25% extension facilitates Surveillance scheduling and considers plant operating conditions that may not be suitable for conducting the Surveillance (e.g., transient conditions or other ongoing Surveillance or maintenance activities). The utilization of the 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements. The utilization of the 24 hour delay period allows adequate time to complete a Surveillance that has been missed. The basis for this delay period includes consideration of unit conditions, the time required to perform the surveillance, the safety significance of the delay in completing the required surveillances, and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the requirements. This change is consistent with NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   This change proposes to apply the requirements of SR 3.0.2 (allowing an extension of 1.25 times the Surveillance interval) and SR 3.0.3 (allowing 24 hours to perform the test if missed) to the Inservice Test Program test intervals. The proposed change does not affect the probability of an accident. The Frequency of inservice test performance is not assumed to

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_3 Labeled Comment/Discussion for ITS 5.0)

1. (continued)

be an initiator of any analyzed event. The change will not allow continuous operation such that a single failure will preclude the associated function from being performed. It is overly conservative to assume that systems or components are inoperable when a Surveillance Requirement is not performed. The opposite is in fact the case, the vast majority of the Surveillance Requirements performed demonstrate systems or components are Operable. When a Surveillance Requirement is not performed within the specified interval it is primarily a question of Operability that has not been verified by performance of the Surveillance Requirement. Therefore, the consequences of an accident previously evaluated are not increased since the most likely outcome of performing a Surveillance is demonstrating the system or component is Operable. This proposed change does not impact the assumptions of any design basis accident. This change will not alter assumptions relative to the mitigation of an accident or transient event. This change will not have any impact on the plant safety. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

This change will not physically alter the plant (no new or different type of equipment will be installed). The changes in methods governing normal plant operation are consistent with the current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

This change proposes to apply the requirements of SR 3.0.2 (allowing an extension of 1.25 times the Surveillance interval) and SR 3.0.3 (allowing 24 hours to perform the test if missed) to the Inservice Test Program test intervals. The margin of safety is not reduced because of this change. This is based on the recognition that the most probable result of any particular Surveillance being performed is demonstrating the system or component is Operable. In addition, this change provides the benefit of avoiding potential plant transients by allowing Surveillance scheduling to

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_3 Labeled Comment/Discussion for ITS 5.0)

3. (continued)

take into consideration plant conditions, provide for adequate planning, and allow for performance of the Surveillance in an orderly manner. This proposed change has no affect on the assumptions of the design basis accident. The safety analysis assumptions will still be maintained, thus no question of safety exists. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_4 Labeled Comment/Discussion for ITS 5.0)

Generic Letter No. 82-12 provided licensees with an NRC policy statement concerning the factors causing fatigue of operating personnel at nuclear reactors. This policy statement concluded that licensees of operating plants shall establish controls to prevent situations where fatigue could reduce the ability of operating personnel to keep the reactor in a safe condition. The controls should focus on shift staffing and the use of overtime that influences fatigue. The objective of the controls would be to assure that, to the extent practical, personnel are not assigned to shift duties while in a fatigued condition that could significantly reduce their mental alertness or their decision making capabilities. These controls apply to the plant staff who perform safety related functions.

Generic Letter No. 82-16 supplemented the policy statement by providing licensees with sample Technical Specifications that limit the amount of overtime worked by plant staff performing safety related functions.

The current additional restrictions for the shift operators were based on guidance provided in NUREG/CR-4248. However, this guidance was never formally adopted into a revised policy statement.

The guidance provided in Generic Letter No. 82-12, as supplemented by Generic Letter No. 82-16, is the current NRC policy regarding overtime work restrictions and has been adopted by many operating reactors. Although the proposed changes relax overtime work restrictions for shift operators, the guidance of Generic Letters Nos. 82-12 and 82-16 will ensure that adequate levels of safety are maintained as demonstrated by the use of this guidance throughout the nuclear industry.

In the case of the remaining individuals who perform safety related functions, overtime restrictions are not relaxed.

Management oversight for all individuals who perform safety related functions, which includes shift operators, will be maintained in that the Plant Manager, or personnel designated in administrative procedures, will continue to monitor the shift overtime. Additionally, individual overtime will be monitored by the Plant Manager, or the appropriate designated personnel, on a monthly basis.

In the case of control room operators, additional initiatives have been taken to reduce fatigue. These initiatives include:

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_4 Labeled Comment/Discussion for ITS 5.0) - continued

(a) moving a greater portion of workload to the weekend backshifts which has reduced the workload during the week,

(b) an enhanced fitness for duty program in which supervisors have been trained in recognizing the appropriate fitness for duty,

(c) an improved performance management process which will ensure employee accountability,

(d) and, improved planning of maintenance activities to reduce overtime.

Therefore, PECO Energy is proposing to relax restrictive working hour limits for shift operators contained in PBAPS Technical Specification Section 6.20, "Site Staff Working Hour Restrictions," and revise the wording in Section 6.20 and delete its Bases (current page 272) to conform with the guidance of Generic Letter No. 82-16 and NUREG-1433.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   Relaxation of the current restrictive working hour limits for shift operators and revising the wording to conform with the guidance provided in Generic Letters Nos. 82-12 and 82-16 will not increase the probability or consequences of an accident previously evaluated. This change is an administrative change that has no impact on the accident precursors of any PBAPS UFSAR Chapter 14 accidents. Industry guidelines are in place which provide appropriate limits to prevent excessive periods of work or chronic overtime that may possibly lead to operator errors. The guidance provided in Generic Letters Nos. 82-12 and 82-16 is the current NRC policy regarding overtime limits and has been adopted for usage at many operating reactors. Overly restrictive guidance provided in NUREG/CR-4248 was never formally adopted for use at operating reactors. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_4 Labeled Comment/Discussion for ITS 5.0) - continued

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   Relaxation of the current restrictive working hour limits for shift operators and revising the wording to conform with the guidance provided in Generic Letter No. 82-16 will not create the possibility of a new or different type of accident previously evaluated. This change is an administrative change that will have no effect on accidents previously evaluated. Controls provided through the guidance of Generic Letters Nos. 82-12 and 82-16 will reduce the probability of excessive fatigue which may result in the deterioration of operator attention that may result in a new or different type of accident from any previously evaluated. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   This change will not involve a reduction in the margin of safety. This change will adopt guidance provided in Generic Letters Nos. 82-12 and 82-16 which has been adopted by many operating reactors and has not resulted in a significant plant degradation. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_5 Labeled Comment/Discussion for ITS 5.0)

The proposed change will revise the requirement for the Senior Manager-Operations to hold a Senior Reactor Operator (SRO) license. The change will require the Senior Manager - Operations to either hold an SRO license or have held an SRO license on a similar BWR unit. However, shift personnel would continue to report to the Shift Managers who are required to be licensed as SROs for PBAPS, in accordance with 10 CFR 50.54 (m)(2), and who in turn report directly to the Senior Manager-Operations.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   Revising the requirement for the Senior Manager-Operations to hold an SRO license will not increase the probability or consequences of an accident previously evaluated. The change is an administrative change that has no impact on the accident precursors of any PBAPS UFSAR Chapter 14 accident since the proposed change will still require the Senior Manager-Operations to have held an SRO license. In addition, the Shift Managers are required to hold SROs and will continue to manage shift personnel. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   This change will not physically alter the plant (no new or different type of equipment will be installed). The changes in methods governing normal plant operations are consistent with current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_5 Labeled Comment/Discussion for ITS 5.0) - continued

3. Does this change involve a significant reduction in a margin of safety?

Operations shift personnel will continue to be managed by an SRO licensed individual. Candidates who are not currently holding SRO licenses and who are to be selected for Shift Manager positions must meet the qualification requirements of ANSI N18.1-1971 and the requirements delineated in 10 CFR 50.54(m)(2). In addition, this change is expected to have an overall positive impact on safety by enhancing the Senior Manager-Operations ability to effectively carry out his primary responsibilities and by improving the consistency and continuity of managerial oversight for Operations personnel. Therefore, this change does not involve a significant reduction in a margin of safety.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)
(L_6 Labeled Comment/Discussion for ITS 5.0)

Existing Specification 6.13, which provides high radiation area access control alternatives pursuant to 10 CFR 20.203(c)(2) (revised 10 CFR 20.1601(c)), has been significantly revised as a result of the changes to 10 CFR 20, the guidance provided in Regulatory Guide 8.38 (Control of Access to High and Very High Radiation Areas in Nuclear Power Plants), and current industry technology in controlling access to high radiation areas. The changes include a capping dose rate to differentiate a high radiation area from a very high radiation area, additional requirements for groups entering high radiation areas, and clarification of the need for communication and control of workers in high radiation areas. This change provides acceptable alternate methods for controlling access to high radiation areas. As a result, this change will not decrease the ability to provide control of exposures from external sources in restricted areas.

PECO Energy has evaluated this proposed Technical Specification change and has determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92. The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed alternatives for control of access to high radiation areas are consistent with the intent of 10 CFR 20.1601(a) and (b). The proposed changes do not affect the probability of an accident. The controls used for access to high radiation areas are not assumed in the initiation of any analyzed event. Also, the consequences of an accident are not affected by these changes. These changes are both consistent with good radiological safety practice and will provide an adequate level of radiation protection. These proposed changes do not impact the assumptions of any design basis accident. These changes will not alter assumptions relative to the mitigation of an accident or transient event. These changes have no impact on safe operation of the plant. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

TECHNICAL CHANGES - LESS RESTRICTIVE
(L_6 Labeled Comment/Discussion for ITS 5.0) - continued

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The proposed change will not create the possibility of an accident. This change will not physically alter the plant (no new or different type of equipment will be installed). The changes in methods governing normal plant operation are consistent with the current safety analysis assumptions. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does this change involve a significant reduction in a margin of safety?

   The proposed alternatives for control of access to high radiation areas are consistent with the intent of 10 CFR 20.1601(a) and (b). The margin of safety is not reduced due to these proposed changes. These changes are both consistent with good radiological safety practice and have been found to provide an adequate level of radiation protection. In addition, these changes provide the benefit of ensuring radiation dose to all workers is minimized by providing the flexibility to select the best means of providing a barrier and access control to a high radiation area given the plant location and radiological conditions. These proposed changes have no impact on the safe operation of the plant. The safety analysis assumptions will still be maintained, thus no question of safety exists. Therefore, these changes do not involve a significant reduction in a margin of safety.

This proposed Technical Specification Change has been evaluated against the criteria for and identification of licensing and regulatory actions requiring environmental assessment in accordance with 10 CFR 51.21. It has been determined that the proposed changes meet the criteria for categorical exclusion as provided for under 10 CFR 51.22(c)(9). The following is a discussion of how the proposed Technical Specification Change meets the criteria for categorical exclusion.

10 CFR 51.22 (c)(9): Although the proposed change involves changes to requirements with respect to inspection or surveillance requirements;

(i) the proposed change involves no Significant Hazards Consideration (refer to the No Significant Hazards Consideration section of this Technical Specification Change Request),

(ii) there is no significant change in the types or significant increase in the amounts of any effluents that may be released offsite since the proposed changes do not affect the generation of any radioactive effluents nor do they affect any of the permitted release paths, and

(iii) there is no significant increase in individual or cumulative occupational radiation exposure.

Accordingly, the proposed change meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Based on the aforementioned and pursuant to 10 CFR 51.22(b), no environmental assessment or environmental impact statement need be prepared in connection with issuance of an amendment to the Technical Specifications incorporating the proposed changes of this request.

1.1 Definitions (continued)

MINIMUM CRITICAL POWER RATIO (MCPR)	The MCPR shall be the smallest critical power ratio (CPR) that exists in the core ~~[for each class of fuel]~~. The CPR is that power in the assembly that is calculated by application of the appropriate correlation(s) to cause some point in the assembly to experience boiling transition, divided by the actual assembly operating power.
MODE	A MODE shall correspond to any one inclusive combination of mode switch position, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.
OPERABLE—OPERABILITY	A system, subsystem, ~~train~~ division, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, ~~train~~, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).
PHYSICS TESTS	PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are: a. Described in ~~Chapter [14, Initial Test Program]~~ Section 13.5, Startup and Power of the ~~F~~SAR; b. Authorized under the provisions of 10 CFR 50.59; or c. Otherwise approved by the Nuclear Regulatory Commission.
~~PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)~~	~~The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current reactor vessel fluence period. These pressure and temperature limits~~

B8 C7 C3 P1 B5 P3 B

(continued)

1.1 Definitions

P8

~~PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR) (continued)~~	~~shall be determined for each fluence period in accordance with Specification 5.9.1.2. Plant operation within these operating limits is addressed in LCO 3.4.10, "RCS Pressure and Temperature (P/T) Limits."~~ C9 5.6.6 9 P14
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of ~~[2436]~~ 3458 MWt. B6
~~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:

P2
P7

C4

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.

(continued)

P7

REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME — The RPS RESPONSE TIME shall be that time interval from the opening of the sensor contact up to and including the opening of the trip actuator contacts

B

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.~~2~~3 P.1	~~--------NOTE--------~~ ~~Not applicable when less than or equal to the low power setpoint (LPSP) of the RWM.~~ ~~--------------------~~ P8 Perform SR 3.1.3.2 and SR 3.1.3.3 for each withdrawn OPERABLE control rod.	Condition A concurrent with 24 hours from discovery of THERMAL POWER greater than A
	AND		
	A.~~3~~4 P.11	Perform SR 3.1.1.1.	72 hours
B. Two or more withdrawn control rods stuck.	~~B.1~~	~~Disarm the associated CRD.~~	~~2 hours~~ C6
	~~AND~~ P.5		
	~~B.2~~ 1 P.15	Be in MODE 3.	12 hours
C. One or more control rods inoperable for reasons other than Condition A or B.	C.1	--------NOTE-------- RWM may be bypassed as allowed by LCO 3.3.2.1, if required, to allow insertion of inoperable control rod and continued operation. -------------------- Fully insert inoperable control rod.	3 hours
	AND		
			(continued)

GENERIC CHANGES (continued)

C_{24} This grammatical error was corrected to be consistent with the change approved in NRC-2, C21.

NON-BRACKETED PLANT SPECIFIC CHANGES

P_1 The appropriate PBAPS specific section of the safety analysis report is identified and the plant specific nomenclature UFSAR is used.

P_2 Response Time testing is not required in the current PBAPS TS. Generic studies are in progress/review and show that response time changes (times getting longer), that could impact safety, do not normally vary such that they would not be detected during other required surveillances (e.g., Channel Calibrations). Since the addition of these tests are a major burden to PBAPS, with little gain in safety, the SRs associated with these tests have not been added for any test associated with instrumentation. Therefore, the definitions have also not been added.

P_3 Grammatical error corrected.

P_4 The plant specific ITS numbering has been used.

P_5 Example 1.3-3 and Example 1.3-6 are proposed to be revised to more adequately reflect BWR specific Technical Specification ACTIONS rather PWR specific Technical Specification ACTIONS. In Example 1.3-3, the Completion Times for Condition C are proposed to be revised from "72 hours" to "12 hours." In Example 1.3-6, Required Action A.2 is proposed to be revised from "Reduce THERMAL POWER to ≤ 50 % RTP" to "Place channel in trip." These changes are considered to be editorial in nature since they do not impact the discussions of the associated examples.

P_6 Editorial change for consistency with NUREG-1433.

P_7 The definition of REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME has been revised to be consistent with the PBAPS current licensing basis as described in CTS 4.1.A.

P_8 The PTLR concept will not be used at PBAPS since an NRC approved methodology does not exist for PBAPS.

NON-BRACKETED PLANT SPECIFIC CHANGES (continued)

P_8 The Note has been incorporated into the Completion Time to preclude not meeting the Completion Time if THERMAL POWER is increased above the LPSP of the RWM > 24 hours after the Condition is entered. The Note states that the Required Action does not have to be performed if power is less than or equal to the LPSP. Thus, if this Condition is entered during a startup while below the LPSP, the Required Action does not have to be performed. However, according to Section 1.3, "Completion Times," the 24 hour clock of Required Action A.2 does start. If power is then increased above the LPSP, the Required Action now becomes required, and if the 24 hour clock has expired, the Required Action must be considered not met within the associated Completion Time. This would require entry into Action E, which requires a unit shutdown. The intent of this Required Action was to provide 24 hours to perform the SRs, after the capability to perform them exists (i.e., from discovery of Condition A concurrent with THERMAL POWER greater than the LPSP of the RWM). Therefore, the Completion Time has incorporated this requirement, consistent with other similar requirements in the ITS. B

P_9 Grammatical/typographical errors corrected.

P_{10} The current words of SR 3.1.4.1 require each control rod to be tested if any fuel movement in the RPV occurs. This effectively means that even if only one bundle is moved (e.g., replacing a leaking bundle mid-cycle), all the control rods are required to be tested per the words of the SR. While a generic change to the Bases attempted to ensure that only those rods affected be tested (BWR-18, C2 and C14), PBAPS believes that the Bases change does not preclude misinterpretation of the requirement. The actual SR was not modified and continues to require each rod to be tested. In addition, there are other SRs (SR 3.1.4.3 and SR 3.1.4.4) which require only the affected control rods to be tested, further adding confusion. Therefore, it is proposed that SR 3.1.4.1 be modified to require each rod to be tested following a refueling, and SR 3.1.4.4 be modified to require each affected rod to be tested following fuel movement within the RPV.

NON-BRACKETED PLANT SPECIFIC CHANGES (continued)

P_{11} The scram reactivity analysis assumes, among other things, that there are two "slow" rods adjacent to one another, a third control rod is stuck in the withdrawn position, and a fourth control rod fails to scram during the transient/accident analysis (the single failure). However, the analysis does not assume that the original stuck control rod is adjacent to the two "slow" rods or to another "slow" control rod. If this occurs, the local scram reactivity rate assumed in the analysis might not be met. Therefore, LCO 3.1.3, Required Action A.1 has been added to confirm that when a control rod is found to be stuck, it is properly separated from "slow" control rods. The current Required Actions of Action A have been renumbered to reflect this addition.

P_{12} SR 3.1.3.5 states "Verify each control rod does not go to the withdrawn overtravel position." This has been revised to state "Verify each withdrawn control rod does not go to the withdrawn overtravel position." The word "withdrawn" is being added for consistency with SR 3.10.8.5, which is the same surveillance as SR 3.1.3.5 but includes the word "withdrawn."

P_{13} The Control Rod Scram Time table is proposed to be revised to more completely reflect the deletion of the 0 psig scram time acceptance criteria from the table. The deletion of the 0 psig scram time acceptance criteria was approved in Generic Change BWR-13, C6, and Revision 3 to BWR-13, C6. Note (b) is proposed to be revised to state "When reactor steam dome pressure is < 800 psig, established scram time limits apply." Note (c), which addresses acceptance criteria for testing at intermediate reactor steam dome pressures between 0 psig and 800 psig, is proposed to be deleted. With the deletion of the 0 psig scram time acceptance criteria and the proposed revision to Note (b), Note (c) is no longer required since the acceptance criteria for scram time testing at reactor steam dome pressures < 800 psig are adequately controlled by plant procedures.

An editorial change is also being made to heading of the scram time column of the table due to the deletion of the 0 psig scram time acceptance criteria.

P_{14} Editorial change for consistency with the Writer's Guide.

A

NON-BRACKETED PLANT SPECIFIC CHANGES (continued)

P_{15} In accordance with Specification 1.3 (Completion Times) once a Condition has been entered, subsequent components expressed in the Condition, discovered to be inoperable, will not result in separate entry into the Condition unless specifically stated in individual Specifications. Specification 3.1.3 has an exception (the Note to the ACTIONS) that allows completely separate re-entry into the Condition (for each control rod) and separate tracking of Completion Times are based on this re-entry. As a result, the Required Actions of the Condition continue to apply to each additional failure, with separate Completion Times based on each re-entry into the Condition. Specification 1.3 also states if situations are discovered that require entry into more than one Condition at a time within a single LCO (multiple Conditions), the Required Actions for each Condition must be performed within the associated Completion Time. When in multiple Conditions, separate Completion Times are tracked for each Condition starting from the time of discovery of the situation that required entry into the Condition.

Required Action A.2 of Specification 3.1.3 (Control Rod OPERABILITY) requires, in the event one withdrawn control rod is stuck, the associated control rod drive (CRD) be disarmed within 2 hours. Required Action B.1 of Specification 3.1.3 requires, in the event of two or more stuck control rods, the associated CRD be disarmed within 2 hours. In accordance with Specification 1.3, if two or more withdrawn control rods are stuck, Condition A is entered separately for each withdrawn stuck control rod and the Required Actions of Condition A must be taken for each withdrawn stuck control rod. Specification 1.3 also requires Condition B to be entered concurrently for this situation and the Required Actions of Condition B taken. As a result, Required Action A.2 and Required Action B.1 (which provide the same requirements) must both be applied in the same time period for each withdrawn stuck control rod. Therefore, Required Action B.1 is deleted since the requirement to disarm the associated CRD when in Condition B is adequately addressed by Required Action A.2 and the requirements of Specification 1.3. A corresponding change to the Bases for Required Actions B.1 and B.2 of Specification 3.1.3 has also been made. B

Insert SR 3.3.1.1.12 (B) (C_2) for the addition of SR 3.3.1.1.12, Note 2

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.~~12~~ 14 (P_2)	Perform CHANNEL FUNCTIONAL TEST.	~~[18]~~ 24 (B_1) months
SR 3.3.1.1.~~13~~ 15 (P_2)	~~-----NOTE----- Neutron detectors are excluded. -----~~ (P_2) Perform CHANNEL CALIBRATION.	as modified by BWR-18, C20 (C_2) ~~[18]~~ 24 (B_1) months
~~SR 3.3.1.1.14~~ (P_{27})	~~Verify the APRM Flow Biased Simulated Thermal Power—High time constant is ≤ [7] seconds.~~	~~[18] months~~
SR 3.3.1.1.~~15~~ 17 (P_2)	Perform LOGIC SYSTEM FUNCTIONAL TEST.	~~[18]~~ 24 (B_1) months
SR 3.3.1.1.~~16~~ 13 (P_2)	Verify Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions are not bypassed when THERMAL POWER is ≥ ~~[~~30~~]~~% RTP.	~~[18]~~ 24 (B_1) months
~~SR 3.3.1.1.17~~ (P_{53}) (modified by BWR-18, C21, + Rev 01)	~~-----NOTE----- Neutron detectors are excluded. ----- Verify the RPS RESPONSE TIME is within limits.~~	~~[18] months on a STAGGERED TEST BASIS~~
SR 3.3.1.1.16 (P_3)	Calibrate each radiation detector.	24 months

B

SR 3.3.1.1.18	Verify the RPS RESPONSE TIME is within limits.	24 months

(P_{53})

B

INSERT SR 3.3.1.1.12

(P3)

SR 3.3.1.1.12	------------------NOTE------------------ 1. Neutron detectors are excluded. (C2) 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.	18 months

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 (P41)	2	~~[3]~~	G	SR 3.3.1.1.1 SR 3.3.1.1.~~4~~ 3 SR 3.3.1.1.~~6~~ 5 SR 3.3.1.1.6 ~~SR 3.3.1.1.7~~ (P2) SR 3.3.1.1.~~13~~ 11 ~~SR 3.3.1.1.~~ 17 (P53) SR 3.3.1.1.14	≤ [120/125] divisions of full scale
	5(a)	~~[3]~~	H	SR 3.3.1.1.1 SR 3.3.1.1.~~5~~ 4 (P2) SR 3.3.1.1.~~13~~ 11 ~~SR 3.3.1.1.16~~ 17	≤ [120/125] divisions of full scale
b. Inop	2	~~[3]~~	G	SR 3.3.1.1.14 (P53) ~~SR 3.3.1.1.~~ 3 SR 3.3.1.1.~~16~~ 17 (P2)	NA
	5(a)	~~[3]~~	H	SR 3.3.1.1.~~5~~ 4 SR 3.3.2.2.~~16~~ 17	NA
2. Average Power Range Monitors					
a. ~~Neutron Flux — High, Setdown~~ (P7) Startup High Flux Scram	2	[2]	G	SR 3.3.1.1.1 SR 3.3.1.1.~~4~~ 3 SR 3.3.1.1.~~6~~ 6 SR 3.3.1.1.7 (P2) ~~SR 3.3.1.1.8~~ SR 3.3.1.1.~~14~~ 12 SR 3.3.1.1.~~16~~ 17 SR 3.3.1.1.18 (P53)	≤ [20]% RTP 15.0 (B3)
(C4)	~~5(a)~~	~~[2]~~	~~H~~	~~SR 3.3.1.1.1~~ ~~SR 3.3.1.1.5~~ ~~SR 3.3.1.1.8~~ ~~SR 3.3.1.1.11~~ ~~SR 3.3.1.1.15~~	~~≤ [20]% RTP~~
b. Flow Biased ~~Simulated Thermal Power — High~~ Scram (P7)	1	[2]	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.~~7~~ 7 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.~~1~~ (P2) SR 3.3.1.1.~~14~~ 17 ~~SR 3.3.1.1.19~~ ~~SR 3.3.1.1.~~ SR 3.3.1.1.18 (P53)	≤ ~~[0.58~~ 0.66 W + ~~60]~~ 63.9 % RTP and ≤ ~~[115.5]%~~ RTP(b) (B3)

(continued)

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

(b) ~~[0.58~~ 0.66 W + ~~60]~~ 63.9 % - ~~0.58~~ 0.66 ΔW]% RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating." (B3)

Table 3.3.1.1-1 (page 2 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
2. Average Power Range Monitors (continued)					
c. ~~Fixed Neutron Flux — High~~ P7 Scram Clamp	1	~~[2]~~	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.9 P2 SR 3.3.1.1.~~14~~ 15 SR 3.3.1.1.~~15~~ 17 ~~SR 3.3.1.1.16~~ SR 3.3.1.1.18 P53	≤ ~~[120]%~~ 118.0 RTP B3
~~d. Downscale~~	~~1~~	~~[2]~~	~~F~~	~~SR 3.3.1.1.8 SR 3.3.1.1.9 P2 SR 3.3.1.1.15 17~~	~~≥ [3]% 2.5 RTP B3~~
e. Inop	1,2	~~[2]~~	G	SR 3.3.1.1.8 SR 3.3.1.1.9 P2 SR 3.3.1.1.~~15~~ 17	NA
C4	~~5(a)~~	~~[2]~~	~~H~~	~~SR 3.3.1.1.5 SR 3.3.1.1.6 SR 3.3.1.1.15~~	~~NA~~ B3
3. Reactor ~~Vessel Steam~~ Dome Pressure — High P7	1,2	~~[2]~~	G	SR 3.3.1.1.1 SR 3.3.1.1.9 ~~[SR 3.3.1.1.10]~~ P2 SR 3.3.1.1.~~13~~ 15 SR 3.3.1.1.~~15~~ 17 ~~SR 3.3.1.1.16~~ SR 3.3.1.1.18 P53	≤ ~~[1045]~~ 1085.0 psig
4. Reactor Vessel Water Level — Low, Level 3 P7	1,2	~~[2]~~	G	SR 3.3.1.1.1 SR 3.3.1.1.9 ~~[SR 3.3.1.1.10]~~ P2 SR 3.3.1.1.~~13~~ 15 SR 3.3.1.1.~~15~~ 17 ~~SR 3.3.1.1.16~~ SR 3.3.1.1.18 P53	≥ ~~[10]~~ 1.0 inches B3
5. Main Steam Isolation Valve — Closure	1	~~[8]~~	F	SR 3.3.1.1.9 SR 3.3.1.1.~~13~~ 15 P2 SR 3.3.1.1.~~15~~ 17 ~~SR 3.3.1.1.16~~ SR 3.3.1.1.18 P53	≤ [10]% closed
6. Drywell Pressure — High	1,2	~~[2]~~	G	SR 3.3.1.1.1 SR 3.3.1.1.9 ~~[SR 3.3.1.1.10]~~ P2 SR 3.3.1.1.~~13~~ 15 ~~SR 3.3.1.1.15~~ 17 SR 3.3.1.1.18 P53	≤ ~~[1.92]~~ 2.0 psig B3

(continued)

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

Table 3.3.1.1-1 (page 3 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
7. Scram Discharge Volume Water Level - High					
a. Resistance Temperature Detector	1,2	[2]	G	SR 3.3.1.1.8 ~~SR 3.3.1.1.9~~ ~~[SR 3.3.1.1.10]~~ SR 3.3.1.1.13 ~~SR 3.3.1.1.15~~ SR 3.3.1.1.15	≤ ~~[57.15]~~ 50.0 gallons
	5(a)	[2]	H	~~SR 3.3.1.1.8~~ ~~SR 3.3.1.1.9~~ ~~[SR 3.3.1.1.10]~~ SR 3.3.1.1.13 SR 3.3.1.1.15 17	≤ ~~[57.15]~~ 50 gallons
~~b. Float Switch~~	~~1,2~~	~~[2]~~	~~G~~	~~SR 3.3.1.1.9~~ ~~SR 3.3.1.1.13~~ ~~SR 3.3.1.1.15~~	~~≤ [57.15] gallons~~
	~~5(a)~~	~~[2]~~	~~H~~	~~SR 3.3.1.1.9~~ ~~SR 3.3.1.1.13~~ ~~SR 3.3.1.1.15~~	~~≤ [57.15] gallons~~
8. Turbine Stop Valve - Closure	≥ [30]% RTP	[4]	E	SR 3.3.1.1.9 12 ~~[SR 3.3.1.1.10]~~ SR 3.3.1.1.13 15 SR 3.3.1.1.15 17 ~~SR 3.3.1.1.16~~ ~~SR 3.3.1.1.17~~ SR 3.3.1.1.15	≤ [10]% closed
9. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≥ [30]% RTP	[2]	E	SR 3.3.1.1.9 12 ~~[SR 3.3.1.1.10]~~ SR 3.3.1.1.13 15 ~~SR 3.3.1.1.15~~ SR 3.3.1.1.15 17 ~~SR 3.3.1.1.17~~ SR 3.3.1.1.18	≥ ~~[600]~~ 500 psig
12 ~~10~~. Reactor Mode Switch - Shutdown Position	1,2	~~[2]~~ 1	G	SR 3.3.1.1.12 14 SR 3.3.1.1.15 17	NA
	5(a)	~~[2]~~ 1	H	SR 3.3.1.1.12 14 SR 3.3.1.1.15 17	NA
13 ~~11~~. Manual Scram	1,2	~~[2]~~ 1	G	SR 3.3.1.1.5 9 SR 3.3.1.1.15 17	NA
	5(a)	~~[2]~~ 1	H	SR 3.3.1.1.5 9 SR 3.3.1.1.15 17	NA

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

INSERT FUNCTIONS 10 & 11

P1

INSERT FUNCTION 14

Specification 3.3.1.1

P1

Insert Functions 10 and 11

10. Turbine Condenser - Low Vacuum	1	2	F	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.15 P53 ~~SR 3.3.1.1.17~~ SR 3.3.1.1.18	≥ 23.0 inches Hg vacuum
11. Main Steam Line - High Radiation	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.10 SR 3.3.1.1.16 ~~SR 3.3.1.1.17~~ SR 3.3.1.1.18 P53	≤ 15 X Full Power Background

B A B

P1

Insert Function 14

14. RPS Channel Test Switch	1,2	2	G	SR 3.3.1.1.4 SR 3.3.1.1.17	NA
	5(a)	2	H	SR 3.3.1.1.4 SR 3.3.1.1.17	NA

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 ~~[5.9.2.e]~~. 5.6.7 P10	Immediately
C. P9 ---------NOTE--------- Not applicable to [hydrogen monitor] channels. ---------------------- One or more Functions with two required channels inoperable.	C.1	Restore one required channel to OPERABLE status.	7 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
P9 ~~D. Two [required hydrogen monitor] channels inoperable.~~	~~D.1 Restore one [required hydrogen monitor] channel to OPERABLE status.~~	~~72 hours~~
P2 D ~~E~~. Required Action and associated Completion Time of Condition C ~~or D~~ not met.	D ~~E~~.1 P2 Enter the Condition referenced in Table 3.3.3.1-1 for the channel.	Immediately
P2 E ~~F~~. As required by Required Action D ~~E~~.1 P2 and referenced in Table 3.3.3.1-1.	E ~~F~~.1 P2 Be in MODE 3.	12 hours
P2 F ~~G~~. As required by Required Action D ~~E~~.1 P2 and referenced in Table 3.3.3.1-1. e	F ~~G~~.1 Initiate action in accordance with Specification ~~5.9.2.c~~. 5.6.~~7~~ 6 P40 ~~modified by [illegible]~~	Immediately e

3.3 INSTRUMENTATION

3.3.8.1 Loss of Power (LOP) Instrumentation <For Unit 2> <For Unit 3>

Unit 2 Unit 3

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

AND

The Unit 3 / Unit 2 LOP instrumentation for Functions 1, 2, 3, and 5 in Unit 3 / Unit 2 Table 3.3.8.1-1 shall be OPERABLE.

P46

APPLICABILITY: ~~MODES 1, 2, and 3;~~
When the associated diesel generator ~~is~~ and offsite circuit are required to be OPERABLE by LCO 3.8.1, "AC Sources—Operating," or LCO 3.8.2, "AC Sources—Shutdown."

P39

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
P38 ~~A. One or more channels inoperable.~~	~~A.1 Place channel in trip.~~ Enter the Condition referenced in Table 3.3.8.1-1 for the channel.	~~Immediately~~ ~~1 hour~~
D ~~B.~~ Required Action and associated Completion Time not met. ~~of Condition B or C not met~~	D ~~B.~~1 Declare associated diesel generator (DG) inoperable.	Immediately

P38

INSERT ACTIONS A, B & C

~~- - - Note - - - <Unit 2 only> <Unit 3 only>~~
~~For Unit 2 / 3 channels, the Condition to be entered for this LCO is referenced in Unit 3 / 2 Table 3.3.8.1-1.~~

~~P47~~

P38

Insert Actions A, B and C

B

A. One 4 kV emergency bus with one or two required Function 3 channels inoperable. OR One 4 kV emergency bus with one or two required Function 5 channels inoperable.	A.1 ------NOTE------- Enter applicable Conditions and Required Actions of LCO 3.8.1 for offsite circuits made inoperable by LOP instrumentation. ----------------- Place channel in trip.	14 days
B. Two 4 kV emergency buses with one required Function 3 channel inoperable. OR Two 4 kV emergency buses with one required Function 5 channel inoperable. OR One 4 kV emergency bus with one required Function 3 channel inoperable and a different 4 kV emergency bus with one required Function 5 channel inoperable.	B.1 ------NOTE------- Enter applicable Conditions and Required Actions of LCO 3.8.1 for offsite circuits made inoperable by LOP instrumentation. ----------------- Place the channel in trip.	24 hours

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Insert ACTIONS A, B and C
(continued)

B

C. One or more 4 kV emergency buses with one or more required Function 1, 2, or 4 channels inoperable. <u>OR</u> One 4 kV emergency bus with one required Function 3 channel and one required Function 5 channel inoperable. <u>OR</u> Any combination of three or more required Function 3 and Function 5 channels inoperable.	C.1 ------NOTE------- Enter applicable Conditions and Required Actions of LCO 3.8.1 for offsite circuits made inoperable by LOP instrumentation. ----------------- Place the channel in trip.	1 hour

P38 ~~CONDITIONS REFERENCED FROM REQUIRED ACTION A.1~~

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

FUNCTION	REQUIRED CHANNELS PER BUS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
P7 1. ~~4.16~~ kV Emergency Bus Undervoltage (Loss of Voltage)			
a. Bus Undervoltage	B2 1 ~~[2]~~	~~[SR 3.3.8.1.1]~~ SR 3.3.8.1.2 3 ~~SR 3.3.8.1.3~~ P2 SR 3.3.8.1.4	P43 ~~≥ [2800] V and ≤ [ ] V~~
P24 ~~b. Time Delay~~	~~[2]~~	~~[SR 3.3.8.1.2]~~ ~~SR 3.3.8.1.3~~ ~~SR 3.3.8.1.4~~	~~≥ [ ] seconds and ≤ [6.8] seconds~~
P7 2. ~~4.16~~ kV Emergency Bus Undervoltage (Degraded Voltage) Low Setting P7			
a. Bus Undervoltage	~~[2]~~ (1 per source) P41	~~[SR 3.3.8.1.1]~~ SR 3.3.8.1.2 ~~SR 3.3.8.1.3~~ P2 SR 3.3.8.1.4	≥ ~~[3280]~~ 2286 V and ≤ [ ] 2709 V B3
b. Time Delay	~~[2]~~ (1 per Source) P41	~~[SR 3.3.8.1.2]~~ 1 SR 3.3.8.1.~~3~~ 2 SR 3.3.8.1.4 P2	≥ ~~[ ]~~ 1.6 seconds and ≤ ~~[21.5]~~ 2.0 seconds B3

INSERT FUNCTION 3, 4 & 5 P24

INSERT FUNCTION 3, 4, & 5

P24

3. 4 kV Emergency Bus Undervoltage (Degraded Voltage High Setting)				
a. Bus Undervoltage	2 (1 per source)	B	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 3411 V and ≤ 3827 V
b. Time Delay	2 (1 per source)	B	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 27.0 seconds and ≤ 33.0 seconds
4. 4 kV Emergency Bus Undervoltage (Degraded Voltage LOCA)				
a. Bus Undervoltage	2 (1 per source)	C	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 3691 V and ≤ 3713 V, with internal time delay set ≥ 0.9 sec, and ≤ 1.1 sec. cnds
b. Time Delay	2 (1 per source)	C	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 8.4 seconds and ≤ 9.6 seconds
5. 4 kV Emergency Bus Undervoltage (Degraded Voltage non-LOCA)				
a. Bus Undervoltage	2 (1 per source)	B	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 4065 V and ≤ 4089 V, with internal time delay set ≥ 0.9 sec, and ≤ 1.1 sec. cnds
b. Time Delay	2 (1 per source)	B	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.4	≥ 57.0 seconds and ≤ 63.0 seconds

B

A

A

NON-BRACKETED PLANT SPECIFIC CHANGES (continued)

P_{38} This change proposes to extend the allowed outage times (AOTs) for Degraded Voltage High Setting and Degraded Voltage Non-LOCA Functions (Functions 3 and 5, respectively, of Table 3.3.8.1-1) from 1 hour to the following:

> 14 days in proposed Condition A when one or two Function 3 channels are inoperable on one 4 kV emergency bus; or
>
> 14 days in proposed Condition A when one or two Function 5 channels are inoperable on one 4 kV emergency bus; or
>
> 24 hours in proposed Condition B when one Function 3 channel is inoperable on each of two 4 kV emergency buses; or
>
> 24 hours in proposed Condition B when one Function 5 channel is inoperable on each of two 4 kV emergency buses; or
>
> 24 hours in proposed Condition B when one Function 3 channel is inoperable on one 4 kV emergency bus and one Function 5 channel is inoperable on a different 4 kV emergency bus.

During MODES 1, 2, and 3, four 4 kV emergency buses from the subject unit and at least two 4 kV emergency buses from the opposite unit are required to have OPERABLE LOP instrumentation. During other MODES or conditions, at least two 4 kV emergency buses from the subject unit and at least one 4 kV emergency bus from the opposite unit are required to have OPERABLE LOP instrumentation. The actual number of 4 kV emergency buses and, as a result, the LOP instrumentation channels required will vary depending on which components are being credited with satisfying Technical Specification requirements and from where these components are being powered.

The 14 day allowed outage time (AOT) when one or two Function 3 channels or when one or two Function 5 channels are inoperable on one 4 kV emergency bus is acceptable because these relays provide only a marginal increase in the voltage monitoring scheme (there is only a small range where the relay protection provided by either of these relays does not overlap with other voltage monitoring relays). In this Condition, autotransfer capability from the normal offsite power source to the alternate power source may be lost from Function 3 or 5 channels for one 4 kV emergency bus. However, autotransfer capability will still be provided by the remaining Function 3 or 5 channels on the affected 4 kV emergency bus while maintaining adequate protection for equipment powered from the affected bus. Therefore, this change has no adverse impact on plant operation. In

NON-BRACKETED PLANT SPECIFIC CHANGES

P_{38} (cont'd) addition, the probability of the grid operating in this unprotected band is extremely remote. There has been no historical evidence of the grid operating in these bands for sufficient time that would have caused operation of these relays. Manual actions can also be taken on the 4 kV emergency bus with the inoperable channels as a result of observed automatic actions on the other 4 kV emergency buses with OPERABLE channels. (The number of other 4 kV emergency buses available with OPERABLE LOP instrumentation channels is based on the number of required 4 kV emergency buses discussed in the previous paragraph.) These actions (manually transferring the 4 kV emergency bus power supply to the alternate source) can be performed without detriment to plant equipment.

The 24 hour AOT when two 4 kV emergency buses have one required Function 3 channel inoperable, or when two 4 kV emergency buses have one required Function 5 channel inoperable, or when one 4 kV emergency bus has one required Function 3 channel inoperable and a different 4 kV emergency bus has one required Function 5 channel inoperable is acceptable based on the discussions above, except that in Condition B autotransfer capability may be lost for the two affected 4 kV emergency buses. Since the degradation addressed in Condition B is more severe than the degradation addressed in Condition A (two 4 kV emergency buses are impacted in Condition B, but only one 4 kV emergency bus is impacted in Condition A), the proposed AOT for Condition B is reduced to 24 hours from the proposed 14 day AOT specified for Condition A. B

P_{39} The Applicability of Specification 3.3.8.1 was revised to reflect the auto-transfer function of the Degraded Voltage LOP Instrumentation.

P_{40} Reference to the PAM Report revised to be consistent with the PBAPS specific ITS numbering.

P_{41} Editorial change made for clarification with no change of intent.

P_{42} The Channel Check requirements were deleted since installed indication from these instruments are not available in the control room. In addition, this is consistent with PBAPS current Technical Specification requirements.

NON-BRACKETED PLANT SPECIFIC CHANGES (continued)

P_{43} The change proposed to delete the requirement for a Channel Calibration and the trip level setting on the undervoltage relay for the Loss of Voltage Function. The PBAPS design intent of the undervoltage relays for the Loss of Voltage Function is to monitor the gross availability of voltage on the respective emergency bus. The relay makes no determination concerning the quality of the voltage. The functional requirements are that the relays operated (de-energize) when there is no source of voltage to the bus, and that it not operate during the load sequencing. These results are achieved by the design process of selecting a device whose dropout is substantially below the anticipated lowest voltage observed during the sequencing, and by functionally verifying that it drops out when the bus is de-energized and that it does not drop out during the sequencing. A Channel Calibration and a trip level setting are therefore not required for the undervoltage relay to perform to satisfy its safety function (starting the DG on a loss of voltage on the emergency bus). The Channel Functional Test will still be performed once per 24 months to ensure that the DG does start on a loss of voltage.

P_{44} This change proposes to allow one manual RPS Function to not maintain trip capability for up to 12 hours. Currently, if an RPS Function is not maintaining trip capability, Action C would require the capability to be restored within 1 hour. By requiring entry into the Action only when two manual Functions are not maintaining trip capability, essentially allows the Required Actions and Completion Times of Condition A to govern the situation. Action A allows 12 hours to place the channels in trip. The PBAPS Technical Specifications includes three manual Functions, versus the two listed in the NUREG. With one manual Function not able to maintain trip capability, there are still two manual Functions maintaining trip capability, consistent with the NUREG.

P_{45} This change proposes to delete the quarterly Channel Functional Test because a quarterly Channel Calibration is performed which, by definition, encompasses the Channel Functional Test.

P_{46} This change was made to account for PBAPS being a dual unit site with equipment from one unit being powered from the other unit. Therefore, the opposite units LOP instrumentation is needed to start the DGs and tie them to the opposite unit's 4 kV emergency buses on a loss of power signal. Appropriate Actions and Surveillance Requirements have been added.

NON-BRACKETED PLANT SPECIFIC CHANGES (continued)

P_{47} This change proposes to modify SR Note 2 to adequately discuss the requirements for allowing the 2 hour delay in entering Action statements when performing SRs. This change modifies the Note to account for PBAPS plant specific differences from the NUREG.

P_{48} This change was made to be consistent with the Writer's Guide.

P_{49} The RBM Bypass Time Delay (Function 1.f) requires performance of a CHANNEL FUNCTIONAL TEST once per 92 days (SR 3.3.2.1.1) and a CHANNEL CALIBRATION once per 184 days (SR 3.3.2.1.5). Notes are proposed to be added for Function 1.f stating the CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION are not required to be performed if the time delay circuit is disabled. The purpose of the RBM Bypass Time Delay Function is to allow the plant, when it is within thermal limits, to withdraw a control rod at least a single notch despite extremely noisy signals that would normally block rod withdrawal. Currently, the LPRM signals have not exhibited excessive noise characteristics that would necessitate use of this time delay. Since this time delay is not needed, the supporting analyses have not been performed and the allowed setting is zero. During the development of the procedures to implement SR 3.3.2.1.1 and SR 3.3.2.1.5 for Function 1.f, it was determined that the allowed setting (zero) is achieved by physically disabling the circuitry that enables the RBM Bypass Time Delay Function on the RBM Delay and Filter Card. As a result, the performance of a CHANNEL FUNCTIONAL TEST or a CHANNEL CALIBRATION is not required to verify the OPERABILITY of Function 1.f when the time delay circuit is disabled. Corresponding changes have also been made to the Bases.

P_{50} Note (b) which states "Also required to initiate the associated DG" has been deleted from the LPCI - Reactor Vessel Water Level - Low Low Low (Level 1) and Drywell Pressure - High Functions (Functions 2.a and 2.b). At Peach Bottom Atomic Power Station (PBAPS), the Diesel Generators (DGs) are initiated from the Core Spray (CS) System initiation logic. The CS and LPCI Reactor Vessel Water Level - Low Low Low (Level 1) and Drywell Pressure - Functions are derived from the same instrumentation. However, any inoperability of the LPCI Reactor Vessel Water Level - Low Low Low (Level 1) or Drywell Pressure - Function that could negatively impact DG initiation will also result in the CS Reactor Vessel Water Level - Low Low Low (Level 1) or Drywell Pressure - Function being inoperable. The CS Reactor Vessel Water Level - Low Low Low (Level 1) and Drywell Pressure - Functions will still include Note (b). Therefore, this change has no impact on DG initiation capability and is being made for consistency with the PBAPS design. Corresponding changes have also been made to the associated Bases. A

NON-BRACKETED PLANT SPECIFIC CHANGES (continued)

P_{51} PBAPS Technical Specification Change Request 93-13 was submitted to reflect the upgrade of the Main Stack and Vent Stack Radiation Monitors. As a result of the upgrade to the Main Stack Radiation Monitor, the Allowable Value for Function 2.c (Primary Containment Isolation - Main Stack Monitor Radiation - High) of Table 3.3.6.1-1 has been revised from 1×10^6 cps to 2×10^{-2} μCi/cc. The new Allowable Value for the Main Stack Radiation Monitors is documented in PECO Energy calculation PE-210 and was developed using the PECO Energy Instrument Setpoint Methodology.

P_{52} Required Action A.1 of Specification 3.3.6.2 specifies placing the inoperable channel in trip in 12 hours for Function 2 (Drywell Pressure-High) or in 24 hours for Functions other than Function 2. The 12 hour allowed outage time was determined to be acceptable for RPS channels in NEDC-30851P-A Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," dated March 1989. Function 2 instrumentation of Specification 3.3.6.2 is common to RPS and as a result is provided with a 12 hour allowed outage time. Function 1 (Reactor Vessel Water Level-Low (Level 3)) instrumentation of Specification 3.3.6.2 is also common to RPS. Therefore, a 12 hour allowed outage time is appropriate for Function 1 and the Completion Times for Required Action A.1 of Specification 3.3.6.2 have been revised accordingly. A

P_{53} RPS RESPONSE TIME Surveillance Requirements have been revised to be consistent with the PBAPS current licensing basis described in CTS 4.1.A. B

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.1 Recirculation Loops Operating

with core flow as a function of THERMAL POWER in the "Unrestricted" Region of Figure 3.4.1-1

P6

LCO 3.4.1 Two recirculation loops with matched flows shall be in operation~~,~~

A

[~~OR~~

P6 and with

One recirculation loop ~~may~~ shall be in operation ~~provided~~ the following limits ~~are~~ applied when the associated LCO is applicable:

P6

a. LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," single loop operation limits ~~[~~specified in the COLR~~];~~

b. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," single loop operation limits ~~[~~specified in the COLR~~];~~ and

c. LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," Function 2.b (Average Power Range Monitors Flow Biased ~~Simulated Thermal Power—High~~ High Scram), Allowable Value of Table 3.3.1.1-1 is reset for single loop operation.]

B13

A

A

A

APPLICABILITY: MODES 1 and 2.

ACTIONS

P6

Insert Actions 1

CONDITION	REQUIRED ACTION	COMPLETION TIME
D ~~A.~~ Requirements of ~~the~~ LCO not met ~~.~~ for reasons other than Conditions A, B, C, and F.	D ~~A.1~~ P6 Satisfy the requirements of the LCO.	24 hours

~~*Pending resolution of stability issues.~~ P6

(continued)

NOTE

Required limit modifications for single recirculation loop operation may be delayed for up to 12 hours after transition from two recirculation loop operation to single recirculation loop operation

P14

B

P2

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.~~10~~ 9 RCS Pressure and Temperature (P/T) Limits

P2

LCO 3.4.~~10~~ 9 RCS pressure, RCS temperature, RCS heatup and cooldown rates, and the recirculation pump starting temperature requirements shall be maintained within ~~the~~ limits ~~specified in the PTLR.~~ - P15 P15 P15

B

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 MODES 1, 2, ~~and~~ or 3. P4	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

A

(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
	AND		
	C.2	Determine RCS is acceptable for operation.	Prior to entering MODE 2 or 3.

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.4.~~10~~ 9.1 P2	-------------------NOTE------------------- Only required to be performed during RCS heatup and cooldown operations and RCS inservice leak and hydrostatic testing. --- Verify: P15 a. ~~Verify~~ RCS pressure, P15 RCS temperature, ~~and RCS heatup and cooldown rates~~ and are within the applicable P15 limits specified in ~~the PTLR.~~ Figures 3.4.9-1 and 3.4.9-2; and b. RCS heatup and cooldown rates are ≤ 100°F in any 1 hour period. P15	30 minutes P15
SR 3.4.~~10~~ 9.2 P2	Verify RCS pressure and RCS temperature are within the criticality limits specified in ~~the PTLR.~~ Figure 3.4.9.3 P15	Once within 15 minutes prior to control rod withdrawal for the purpose of achieving criticality
		(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.~~10.3~~ 9 P2	--------------------NOTE-------------------- Only required to be met in MODES 1, 2, 3, and 4 ~~[with reactor steam dome pressure ≥ 25 psig]~~ during recirculation pump startup P13. -- Verify the difference between the bottom head coolant temperature and the reactor pressure vessel (RPV) coolant temperature is ~~within the limits specified in the PTLR~~ ≤ 145°F P15.	B11 Once within 15 minutes prior to each startup of a recirculation pump
SR 3.4.~~10.4~~ 9 P2	--------------------NOTE-------------------- Only required to be met in MODES 1, 2, 3, and 4. -- Verify the difference between the reactor coolant temperature in the recirculation loop to be started and the RPV coolant temperature is ~~within the limits specified in the PTLR~~ ≤ 50°F P15.	Once within 15 minutes prior to each startup of a recirculation pump
SR 3.4.~~10~~ 9 .5 P2	--------------------NOTE-------------------- Only required to be performed when tensioning the reactor vessel head bolting studs. -- Verify reactor vessel flange and head flange temperatures are ~~within the limits specified in the PTLR~~ > 70°F P15.	30 minutes

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.~~10~~ 9.6 P2	------------------NOTE------------------ Not required to be performed until 30 minutes after RCS temperature ≤ 80°F in MODE 4. -- Verify reactor vessel flange and head flange temperatures are ~~within the limits specified in the PTLR.~~ > 70°F P15	30 minutes
SR 3.4.~~10~~ 9.7 P2	------------------NOTE------------------ Not required to be performed until 12 hours after RCS temperature ≤ 100°F in MODE 4. -- Verify reactor vessel flange and head flange temperatures are ~~within the limits specified in the PTLR.~~ > 70°F P15	12 hours

B

B

Add:

P15

Figure 3.4.9 - 1, Temperature / Pressure Limits for Inservice Hydrostatic and Inservice Leakage Tests

Figure 3.4.9 - 2, Temperature / Pressure Limits for Non-Nuclear Heatup and Cooldown Following a Shutdown

Figure 3.4.9 - 3, Temperature / Pressure Limits for Criticality

B

NON-BRACKETED PLANT SPECIFIC CHANGES (continued)

P_{14} In Table 3.3.1.1-1 of Specification 3.3.1.1, Reactor Protection System, an Allowable Value for the Average Power Range Monitor (APRM) Flow Biased High Scram during single loop operation is specified. Specification 3.4.1, Recirculation Loops Operating, specifies single loop operation limits including resetting the APRM Flow Biased High Scram Allowable Value. Required Action D.1 of Specification 3.4.1 allows 24 hours to satisfy the LCO. This would allow 24 hours to recalibrate the APRM Flow Biased High Scram setpoints if the unit was going to stay in single loop operation. However, as proposed in PBAPS TSCR 93-16, this must be done using the provisions of Required Action D.1 of Specification 3.4.1. As a result, since the ACTIONS of Specification 3.4.1 are entered to establish the single loop operation limits, it could be misinterpreted that the APRM Flow Biased High Scram Function is inoperable and the ACTIONS of Specification 3.3.1.1 must also be entered.

In order to eliminate any confusion brought on by the inconsistency with Specification 3.3.1.1, Reactor Protection System Instrumentation, and the need to enter Condition D of Specification 3.4.1, Recirculation Loops Operating, just to transition from two loop operation to single loop operation (Condition D allows 24 hours to reset the APRM settings to the single loop values, but Specification 3.3.1.1 does not provide a 24 hour Completion Time for inoperable APRM channels) a Note is proposed to be added to LCO 3.4.1. The proposed Note to LCO 3.4.1 states "Required limit modifications for single recirculation loop operation may be delayed for up to 12 hours after transition from two recirculation loop operation to single loop operation." As a result, modification of limits for single loop operation would now be done without the need to enter ACTIONS (provided the modifications to the limits can be completed within 12 hours). A corresponding change to the Bases of Specification 3.4.1 has also been made. B

P_{15} The PTLR concept will not be used at PBAPS, as a result the P/T limits have been explicitly stated in the PBAPS ITS consistent with the PBAPS CTS.

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

3.5.2 ECCS—Shutdown

LCO 3.5.2 Two low pressure ECCS injection/spray subsystems shall be OPERABLE ; and no operations with a potential for draining the reactor vessel (OPDRVs) in progress. P7 B

APPLICABILITY: MODE 4,
MODE 5, except with the spent fuel storage pool gates removed ~~and~~, water level ≥ ~~[23 ft] over the top of the~~ 458 inches above instrument zero reactor pressure vessel ~~flange~~. B12 B12

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)~~. P7	Immediately
C. Two required ECCS injection/spray subsystems inoperable.	C.1	Initiate action to suspend OPDRVs.	Immediately
	AND		
	C.2	Restore one ECCS injection/spray subsystem to OPERABLE status.	4 hours

(continued)

NON-BRACKETED PLANT SPECIFIC CHANGES (continued)

P_5 A new Condition (2nd Condition for Condition A) was added to allow one LPCI pump in each subsystem to be inoperable for 7 days. This condition is essentially the same as one complete LPCI subsystem being inoperable, which is currently allowed for 7 days. See the Discussion of Change for ITS 3.5.1 for further justification of this change. Due to this addition, proposed Condition I was modified to state that the two subsystems are inoperable "for reasons other than Condition A," since the pump inoperable in each subsystem means that both LPCI subsystems are inoperable.

P_6 Generic change BWR-18, C58 changed to Completion Time from Immediately to 1 hour. However, due to the mechanics of how Completion Times work, the 1 hour allowance can probably never be used. For example, if HPCI is inoperable, LCO 3.5.1, Condition C is entered, and the 1 hour verification of Required Action C.1 is performed. If RCIC is not inoperable at this time, the Required Action is met. However, since the Completion Time starts upon entry into the Condition, if RCIC later becomes inoperable, the 1 hour time in the HPCI Action has already expired. Thus a unit shutdown would be required immediately upon discovery of RCIC being inoperable, even though the RCIC Action (LCO 3.5.3, Required Action A.1) appears to allow 1 hour to verify HPCI operability. To avoid this confusion, the original time allowed by the NUREG has been used.

P_7 Specification 3.5.2, ECCS-Shutdown, requires low pressure ECCS subsystems to be OPERABLE in MODE 4 and in MODE 5 except when the spent fuel storage pool gates are removed and water level is ≥ 458 inches above reactor pressure vessel instrument zero. CTS 3.5.F.1 specifies low pressure ECCS subsystem requirements for the same conditions specified in Specification 3.5.2 of the PBAPS ITS with one exception. The CTS also requires low pressure ECCS subsystems to be OPERABLE when operations with a potential for draining the reactor vessel are in progress. This requirement was added to the CTS in Amendments 195 and 199 for Unit 2 and Unit 3, respectively, on September 16, 1994. However, this was after the cutoff date for changes to the PBAPS ITS submittal. As such, the Applicability of Specification 3.5.2 is now proposed to be revised to achieve consistency with the Applicability for low pressure ECCS subsystems in CTS 3.5.F.1. The Applicability of Specification 3.5.2 is proposed to require low pressure ECCS subsystems to be OPERABLE in MODE 4 and in MODE 5, except when the spent fuel storage pool gates are removed, water level is ≥ 458 inches above reactor pressure vessel instrument zero, and no operations with a potential for draining the reactor vessel are in progress. A corresponding change to the Bases for Specification 3.5.2 has also been made. B

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.6.1.2.1	------------------NOTES------------------ 1. An inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. 2. Results shall be evaluated against acceptance criteria of SR 3.6.1.1.1 in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions. --- Perform required primary containment air lock leakage rate testing in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions. P13 The acceptance criteri~~a~~ on for air lock testing ~~are:~~ is P13 ~~a.~~ Overall air lock leakage rate ~~is~~ ≤ ~~[0.05 L_a]~~ 9000 scf/min when tested at ≥ P_a. B1 ~~b. For each door, leakage rate is ≤ [0.01 L_a] when the gap between the door seals is pressurized to [≥ 10 psig for at least 15 minutes].~~ P13	-----NOTE------ SR 3.0.2 is not applicable --------------- In accordance with 10 CFR 50, Appendix J, as modified by approved exemptions
SR 3.6.1.2.2	------------------NOTE------------------ ~~Only required to be performed upon entry into primary containment when the primary containment is de-inerted.~~ STEP ~~air lock~~ ~~B.2~~ --- Verify only one door in the primary containment air lock can be opened at a time.	~~or exit through the~~ 184 days

B

3.6 CONTAINMENT SYSTEMS

3.6.1.3 Primary Containment Isolation Valves (PCIVs)

C3

LCO 3.6.1.3 Each PCIV shall be OPERABLE. except reactor building-to-suppression chamber vacuum breakers and scram discharge volume vent and drain valves. P17

APPLICABILITY: MODES 1, 2, and 3,
When associated instrumentation is required to be OPERABLE per LCO 3.3.6.1, "Primary Containment Isolation Instrumentation."

ACTIONS

P8

or exhaust

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

1. Penetration flow paths ~~[except for purge valve penetration flow paths]~~ may be unisolated intermittently under administrative controls.
2. Separate Condition entry is allowed for each penetration flow path.
3. Enter applicable Conditions and Required Actions for systems made inoperable by PCIVs.
4. Enter applicable Conditions and Required Actions of LCO 3.6.1.1, "Primary Containment," when PCIV leakage results in exceeding overall containment leakage rate acceptance criteria. ~~in MODES 1, 2 and 3~~ P18

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. ---------NOTE--------- Only applicable to penetration flow paths with two PCIVs. --------------------- One or more penetration flow paths with one PCIV inoperable ~~[except for purge valve leakage not within limit]~~. P23 MSIV ~~Modified by BWR-SC P~~	A.1	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.	4 hours except for main steam line AND 8 hours for main steam line
	AND		(continued)

B

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. ---------NOTE--------- Only applicable to penetration flow paths with two PCIVs. ---------------------- One or more penetration flow paths with two PCIVs inoperable ~~[except for purge valve leakage not within limit]~~. MSIV P23	B.1	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	1 hour
---------NOTE--------- Only applicable to penetration flow paths with only one PCIV. ---------------------- One or more penetration flow paths with one PCIV inoperable. ~~[except due to leakage not within limit]~~.	C.1	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	~~[4]~~ 9 hours except for excess flow check valves (EFCVs) AND 12 hours ~~[~~for EFCVs~~]~~
	AND		
	C.2	--------NOTE--------- Valves and blind flanges Isolation devices in high radiation areas may be verified by use of administrative means. --------------------- Verify the affected penetration flow path is isolated.	Once per 31 days for isolation devices outside primary containment AND INSERT C P30 P21
D. Secondary containment bypass leakage rate not within limit. One or more penetration flow paths ~~with one~~ or more MSIVs not within P22	D.1	Restore leakage rate to within limit.	~~4~~ 8 hours P22

(continued)

NON-BRACKETED PLANT SPECIFIC CHANGES (continued)

P_{16} The Completion Time for closing an open suppression chamber-to-drywell vacuum breaker has been revised to be consistent with the PBAPS specific licensing basis approved in Amendments Nos. 127 and 130 for Units 2 and 3, respectively.

P_{17} The SDV vent and drain valves are also PCIVs. Thus, SDV vent and drain valves have their own Specification (LCO 3.1.8), this statement excluding SDV vent and drain valves is needed, similar to the statement concerning vacuum breakers approved in BWR-15, C6, Revision 1.

P_{18} These words from BWR-15, C3 (for the Note in the Actions) and BWR-16, C5 (for the Note in NUREG SR 3.6.1.3.13) have not been used since there are no PCIV leakage tests required in Modes other than 1, 2, and 3 for PBAPS (i.e., there are no PCIVs required to be Operable in Modes other than 1, 2, and 3 that have leakage limits). Thus the clarification is not needed. In addition, Note 1 to NUREG SR 3.6.1.3.2 and the Note to NUREG SR 3.6.1.3.15 have not been used for the same reason.

P_{19} Not used.

P_{20} The frequency of "Once per 31 days" was clarified by adding "for isolation devices outside primary containment. Also the new frequency, "Prior to entering MODE 2 or 3 from MODE 4, if not performed within the previous 92 days, for isolation devices inside primary containment," was added. "For isolation devices outside primary containment," was added in order to avoid unnecessary exposure to individuals entering containment to comply with this action for affected valves which may be inside containment. The second frequency is required for valves inside primary containment. It is based on engineering judgement and is considered reasonable in view of the inaccessibility of the valves and other administrative controls ensuring that valve misalignment is an unlikely possibility. This change makes Action C consistent with Actions A and E.

P_{21} These words have been modified consistent with the changes made to the Notes for Required Actions A.2 and E.2, in approved BWR-15, C5.

NON-BRACKETED PLANT SPECIFIC CHANGES (continued)

P_{22} The time to restore MSIV leakage to within limit has been changed to 8 hours, consistent with the time to restore an inoperable MSIV (for reasons other than leakage) in Action A. Action A allows 8 hours to isolate the affected main steam line when an MSIV is inoperable due to a reason not involving leakage. This could include a MSIV that will not automatically isolate (which means it is essentially fully open). Action D was modified to include MSIV leakages (BWR-15, C4), and it appears to not have fully been changed to allow the 8 hours in Action A, which is the Action that would have been entered for a leakage problem prior to the generic change. In addition, since for PBAPS there is only one type of leakage covered in LCO 3.6.1.3, MSIV leakage, this Action has been written specifically for MSIV leakage (there are no limits for hydrostatically tested valves, purge valves, or EFCVs), incorporating as much of the BWR-15, C4 change as possible.

P_{23} Action E and SR 3.6.1.3.7 have been deleted since PBAPS does not have specific leakage requirements for the purge valves. The NRC, in the SER for Amendments 144 (Unit 2) and 146 (Unit 3), dated May 8, 1989, found that replacement of the seals of the purge valves every third refueling outage in conjunction with the SGIG System (proposed SRs 3.6.1.3.1, 3.6.1.3.2, 3.6.1.3.7, and 3.6.1.3.13) was an acceptable method of ensuring leak tightness. (The frequency was modified to be every second refueling outage in Amendments 179 (Unit 2) and 182 (Unit 3), dated August 2, 1993, due to the extension of a refueling outage from 18 months to 24 months.) SR 3.6.1.3.16 has been added to perform the required seal replacement. Appropriate Bases changes have been made to reflect these changes. B

P_{24} The words describing the final position of the EFCVs have been modified to be consistent with other Surveillances that test automatic PCIVs (e.g., NUREG SR 3.6.1.3.9, the MSIV test). The EFCV should actuate to the isolation position. The requirement to restrict flow to $\leq$ 1 gpm has been deleted since the PBAPS analysis basis does not assume a specific leakage through the EFCVs. The leakage will be controlled administratively and will be based on valve design leakage.

P_{25} Surveillance Requirement SR 3.6.1.3.12 has not been used in the PBAPS ITS submittal since the current Unit 2 and Unit 3 licenses do not include this requirement. This type of leakage is part of the overall containment leakage and no special limits apply.

3.8 ELECTRICAL POWER SYSTEMS

<Unit 2 only> <Unit 3 only>

3.8.1 AC Sources—Operating (P1) Unit 2 / Unit 3 (P11)

LCO 3.8.1 The following AC electrical power sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System;

b. (B1) Four ~~[Three]~~ diesel generators (DGs) ~~[,]~~ <For Unit 2> <For Unit 3> (P11) capable of supplying the Unit 2 / Unit 3 onsite Class 1E AC Electrical Power Distribution System and

c. (B2) ~~Three automatic sequencers~~]. (P11) INSERT LCO 3.8.1

B

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One (B2) ~~[required]~~ offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for OPERABLE (B2) ~~[required]~~ offsite circuits (P1)	1 hour AND Once per 8 hours thereafter
	AND	
	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 (P2) 4 kV emergency bus ~~division~~ concurrent with inoperability of redundant required feature(s)
	AND	
		(continued)

INSERT LCO 3.8.1

P11

<FOR UNIT 2>

c. The qualified circuit(s) between the offsite transmission network and the Unit 3 onsite Class 1E AC electrical power distribution subsystem(s) needed to support the Unit 3 powered equipment required to be OPERABLE by LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," LCO 3.7.3, "Emergency Heat Sink," and LCO 3.8.4, "DC Sources—Operating"; and

d. The DG(s) capable of supplying the Unit 3 onsite Class 1E AC electrical power distribution subsystem(s) needed to support the Unit 3 powered equipment required to be OPERABLE by LCO 3.6.4.3, LCO 3.7.3, and LCO 3.8.4.

<FOR UNIT 3>

c. The qualified circuit(s) between the offsite transmission network and the Unit 2 onsite Class 1E AC electrical power distribution subsystem(s) needed to support the Unit 2 powered equipment required to be OPERABLE by LCO 3.6.3.1, "Containment Atmospheric Dilution ( ) System," LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," LCO 3.7.2, "Emergency Service Water (ESW) System and Normal Heat Sink," LCO 3.7.4, "Main Control Room Emergency Ventilation (MCREV) System," and LCO 3.8.4, "DC Sources—Operating"; and

d. The DG(s) capable of supplying the Unit 2 onsite Class 1E AC electrical power distribution subsystem(s) needed to support the Unit 2 powered equipment required to be OPERABLE by LCO 3.6.3.1, LCO 3.6.4.3, LCO 3.7.2, LCO 3.7.4, and LCO 3.8.4.

8

Specification 3.8.2

(P11)

INSERT LCO 3.8.2

<FOR UNIT 2>

c. One qualified circuit between the offsite transmission network and the Unit 3 onsite Class 1E AC electrical power distribution subsystem(s) needed to support the Unit 3 powered equipment required to be OPERABLE by LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," and LCO 3.8.5, "DC Sources—Shutdown"; and

d. One DG capable of supplying one Unit 3 onsite Class 1E AC electrical power distribution subsystem needed to support the Unit 3 powered equipment required to be OPERABLE by:

1. LCO 3.6.4.3.

<u>OR</u>

2. LCO 3.8.5

<FOR UNIT 3>

al

c. One qualified circuit between the offsite transmission network and the Unit 2 onsite Class 1E AC electric power distribution subsystem(s) needed to support the Unit 2 powered equipment required to be OPERABLE by LCO 3.6.4.3, "Standby Gas Treatment (SGT) System", LCO 3.7.4, "Main Control Room Emergency Ventilation (MCREV) System," and LCO 3.8.5, "DC Sources—Shutdown"; and

B

d. The DG(s) capable of supplying one subsystem of each of the Unit 2 powered equipment required to be OPERABLE by LCO 3.6.4.3, LCO 3.7.4, and LCO ~~3.7.5~~. 8

A

The 7 day frequency is not applicable if the battery is on equalize charge or has been on equalize charge at any time during the previous 1 day (P31)

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.8.4.1	Verify battery terminal voltage is ≥ ~~[120]~~ 123.5 (B1) V on float charge.	7 days AND 14 days. (P31)
SR 3.8.4.2	Verify no visible corrosion at battery (C8) terminals and connectors. OR Verify battery (C8) connection resistance ~~[is~~ ≤ ~~[1.5E-4 ohm] for inter-cell connections, ≤ [1.5E-4 ohm] for inter-rack connections, ≤ [1.5E-4 ohm] for inter-tier connections, and ≤ [1.5E-4 ohm] for terminal connections]~~ 40 E-6 ohm (B1).	92 days
SR 3.8.4.3	Verify battery (C8) cells, cell plates, and battery racks show no visual indication of physical damage or abnormal deterioration that could potentially degrade battery performance. (P35)	~~[12]~~ months
SR 3.8.4.4	Remove visible corrosion (C9) and verify battery (C8) cell to cell and terminal connections are ~~[clean and tight, and]~~ coated with anti-corrosion (C9) material.	~~[12]~~ months
SR 3.8.4.5	Verify battery (C8) connection resistance ~~[is~~ ≤ ~~[1.5E-4 ohm] for inter-cell connections, ≤ [1.5E-4 ohm] for inter-rack connections, ≤ [1.5E-4 ohm] for inter-tier connections, and ≤ [1.5E-4 ohm] for terminal connections]~~ 40 E-6 ohm (B1).	[12] months

(P14)

NOTE

SR 3.8.4.1 through SR 3.8.4.6 are applicable only to the Unit 2/Unit 3 DC electrical power subsystems. SR 3.8.4.7 is applicable only to the Unit 3/Unit 2 DC electrical power subsystems.

(continued)

INSERT LCO 3.8.7

P15

<FOR UNIT 2>

a. Unit 2 Division I and Division II AC and DC electrical power distribution subsystems; and

b. Unit 3 AC and DC electrical power distribution subsystems needed to support equipment required to be OPERABLE by LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown," LCO 3.5.1, "ECCS—Operating," LCO 3.6.2.3, "RHR Suppression Pool Cooling," LCO 3.6.2.4, "RHR Suppression Pool Spray," LCO 3.6.3.1, "Containment Atmospheric Dilution (CAD) System," LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," LCO 3.7.1, "High Pressure Service Water (HPSW) System," LCO 3.7.2, "Emergency Service Water (ESW) System and Normal Heat Sink," LCO 3.7.3, "Emergency Heat Sink," and LCO 3.8.1, "AC Sources—Operating."

<FOR UNIT 3>

a. Unit 3 Division ~~1~~ I and Division ~~2~~ II AC and DC electrical power distribution subsystems; and B

b. Unit 2 AC and DC electrical power distribution subsystems needed to support equipment required to be OPERABLE by LCO 3.4.7, "Residual Heat Removal (RHR Shutdown Cooling System—Hot Shutdown," LCO 3.5.1, "ECCS—Operating," LCO 3.6.2.3, "RHR Suppression Pool Cooling," LCO 3.6.2.4, "RHR Suppression Pool Spray," LCO 3.6.3.1, "Containment Atmospheric Dilution (CAD) System," LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," LCO 3.7.1, "High Pressure Service Water (HPSW) System," LCO 3.7.2, "Emergency Service Water (ESW) System and Normal Heat Sink," LCO 3.7.3, "Emergency Heat Sink," LCO 3.7.4, "Main Control Room Emergency Ventilation (MCREV) System," and LCO 3.8.1, "AC Sources—Operating."

NON-BRACKETED PLANT SPECIFIC CHANGES

P_{31} (cont'd) completed an equalize charge. The 14 day Frequency has been added to ensure that the battery cannot be placed on equalize all the time, thus the SR would never be required. This ensures the SR is performed at least every 14 days, regardless of how often the battery is placed on equalize. This 14 days is still conservative with respect to the recommendations of IEEE-450, 1987.

P_{32} Typographical errors corrected.

P_{33} The Actions have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in Mode 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in Mode 1, 2, or 3, the fuel movement is independent of reactor operations. In either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown. Therefore, the Note has been added consistent with other placed where the Note appears in the ITS (e.g., ITS 3.6.4.3, Standby Gas Treatment System). The Note applies to more than one of the Required Actions, thus it has been placed at the beginning of the Actions Table.

P_{34} This change was made to be consistent with similar changes approved in CEOG-01, C1.

P_{35} SR 3.8.4.3 requires a verification be performed once per 12 months that battery cells, cell plates, and racks show no visual indication of physical damage or abnormal deterioration. The Bases for SR 3.8.4.3 in NUREG-1433 and the PBAPS ITS state that this SR "provides an indication of physical damage or abnormal deterioration <u>that could potentially degrade battery performance</u>". As a result, it is interpreted that physical damage or abnormal deterioration has to be of a type that could potentially degrade battery performance before the SR would fail to be met. The presence of physical damage or deterioration does not necessarily represent a failure of SR 3.8.4.3, provided an evaluation determines that the physical damage or deterioration does not affect the OPERABILITY of the battery (its ability to perform its design function). Therefore, for consistency with the Bases for SR 3.8.4.3 in NUREG-1433 and the PBAPS ITS, SR 3.8.4.3 is proposed to be revised to read "Verify battery cells, cell plates, and racks show no visual indication of physical damage or abnormal deterioration <u>that could potentially degrade battery performance</u>." B

5 P2
5.~~7~~ ~~Procedures~~, Programs, and Manuals

5.~~7.2.7~~ 5.4 P11 Radioactive Effluent Controls Program (continued)

P11 liquid

e. Determination of cumulative and projected dose contributions from liquid radioactive effluents and determination of cumulative dose contributions from gaseous radioactive effluents (P9) for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days; P23

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~~; Insert 5.5.4.f and 5.5.4.g

~~Shall be specified in the ODCM~~ P9

~~g~~ h. P2 Limitations on the dose rate resulting from radioactive material released in gaseous effluents to areas beyond the site boundary ~~conforming to the dose associated with 10 CFR 20, Appendix B, Table II, Column 1~~;

Insert: 5.5.4.~~g~~ h P9

~~h~~ i. P2 Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I;

~~i~~ j. P2 Limitations on the annual and quarterly doses to a member of the public from iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half lives > 8 days in gaseous effluents released from each unit to areas ~~beyond~~ the site boundary, conforming to 10 CFR 50, Appendix I; and P7

~~j~~ k. P2 Limitations on the annual dose or dose commitment to any member of the public due to releases of radioactivity and to radiation ~~from uranium~~ fuel cycle sources, conforming to 40 CFR 190~~; and~~. P7

P6 ~~k. Limitations on venting and purging of the Mark II containment through the Standby Gas Treatment System to maintain releases as low as reasonably achievable (in BWR/4s with Mark II containments).~~

C15 ~~5.7.2.8 Radiological Environmental Monitoring Program~~

~~This program is for monitoring the radiation and radionuclides in the environs of the plant. The program shall provide:~~

(continued)

P23

Insert 5.5.4.f and 5.5.4.g

to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when projected doses averaged over one month would exceed 0.12 mrem to the total body or 0.4 mrem to any organ (combined total from the two reactors at the site);

g. Limitations to ensure gaseous effluents shall be processed, prior to release, through the appropriate gaseous effluent treatment systems as described in the ODCM;

B

Insert: 5.5.4.gh (P9)

B

shall be limited to the following:

1. For noble gases: less than or equal to a dose rate of 500 mrems/yr to the total body and less than or equal to a dose rate of 3000 mrems/yr to the skin, and

2. For iodine-131, iodine-133, tritium, and for all radionuclides in particulate form with half lives > 8 days: less than or equal to a dose rate of 1500 mrems/yr to any organ;

5 5 ~~Procedures,~~ Programs, and Manuals P2

5.5.4 Programs and Manuals (continued)

C16

5.7.2.11 Inservice Inspection Program

This program provides controls for inservice inspection of ASME Code Class 1, 2, and 3 components, including applicable supports. The program shall include the following:

a. Provisions that inservice inspection of ASME Code Class 1, 2, and 3 components shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda, as required by 10 CFR 50.55a;

b. The provisions of SR 3.0.2 are applicable to the frequencies for performing inservice inspection activities;

c. An inservice inspection program for piping identified in NRC Generic Letter 88-01 in accordance with the NRC staff positions on schedule, methods, personnel, and sample expansion included in Generic Letter 88-01, or in accordance with alternate measures approved by the NRC staff; and

d. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any TS.

P2 5.5.6 Inservice Testing Program

This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components including applicable supports. The program shall include the following: STET B

C17

a. ~~Provisions that inservice testing of ASME Code Class 1, 2, and 3 pumps, valves, and snubbers shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda, as required by 10 CFR 50.55a;~~

STET ~~b.~~ a. P2 Testing frequencies specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda are as follows: B

(continued)

P2 5

5.1 ~~Procedures~~, Programs, and Manuals

5.7.2.12 Inservice Testing Program (continued)

P2 5.6

STET

C4

ASME Boiler and Pressure Vessel Code and applicable Addenda terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

2 P3

b ~~a~~ c. The provisions of SR 3.0.2 are applicable to the ~~above required~~ Frequencies for performing inservice testing activities;

C17

c ~~b~~ d. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d ~~e~~ e. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any TS.

B B B

P2 5.7.2.13 Ventilation Filter Testing Program (VFTP)

5.7

The VFTP ~~A program~~ shall be established ~~to implement~~ the ~~following~~ required testing of Engineered Safety Feature (ESF) filter ventilation systems. ~~at the frequencies specified in [Regulatory Guide], and in accordance with [Regulatory Guide 1.52, Revision 2, ASME N510-1989; and AG-1]~~.

Insert 5.5.7a

P3

Insert A from Page 5.0-27 P17

(continued)

5.0 ~~Procedures~~ Programs and Manuals

5.9 ~~2.15~~ Diesel Fuel Oil Testing Program (continued) ~~procedures based on~~

acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

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

1. an API gravity or an absolute specific gravity within limits, , when required, and a flash point

2. ~~a flash point and~~ kinematic viscosity within limits for ASTM 2-D fuel oil, and or a water and sediment content within limits

3. a clear and bright appearance with proper color;

b. Other properties for ASTM 2-D fuel oil are within limits within 31 ~~30~~ days following sampling and addition to storage tanks; and

c. Total particulate concentration of the fuel oil is ≤ 10 mg/l when tested every 31 days ~~in accordance with ASTM D-2276, Method A-2 or A-3~~ STET, except that filters specified in the ASTM method may have a nominal pore size of up to three (3) microns.

Insert: Section 5.5.10 from page 5.0-16

~~5.7.2.16 Fire Protection Program~~

~~This program provides controls to ensure that appropriate fire protection measures are maintained to protect the plant from fire and to ensure the capability to achieve and maintain safe shutdown in the event of a fire is maintained.~~

6 P2 6

5.9 Reporting Requirements

6.5

5.9.1.6 CORE OPERATING LIMITS REPORT (COLR) (continued)

B2 INSERT TP

[Identify the Topical Report(s) by number, title, date, and NRC staff approval document, or identify the staff Safety Evaluation Report for a plant specific methodology by NRC letter and date.]

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.

C22 ing, as well as heatup and cooldown rates

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

6.6 P25

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

P16 heatup, cooldown, low temperature operation

a. ~~The~~ RCS pressure and temperature limits, including heatup and cooldown rates, criticality, and hydrostatic ~~and leak~~ test ~~limits~~, shall be established and documented in the PTLR. ~~[The individual Specifications that address the reactor vessel pressure and temperature limits and the heatup and cooldown rates may be referenced.]~~ The analytical methods used to determine the pressure and temperature limits ~~including the heatup and cooldown rates~~ shall be those previously reviewed ~~and approved~~ by the NRC in [Topical Report(s), number, title, date, and NRC staff approval document, or staff safety evaluation report for a plant specific methodology by NRC letter and date]. ~~The reactor vessel pressure and temperature limits, including those for heatup and cooldown rates, shall be determined so that all applicable limits (e.g., heatup limits, cooldown limits, and inservice leak and hydrostatic testing limits) of the analysis are met.~~ The PTLR, ~~including revisions or supplements thereto,~~ shall be provided upon issuance for each reactor vessel fluency period to the NRC and for any revision or supplement thereto.

C22 ~~So the following~~ Specification 3.4.9, "RCS Pressure and Temperature (P/T) Limits"

RCS P7

H b. Insert: 5.6.5

H c.

B2 B3 C22

PAM

5.9.2 C21 ~~Special~~ Reports

P2 ~~6.9~~ 6 B4

[Special Reports may be required covering inspection, test, and maintenance activities. These special reports are determined on

B3 Modification by BWR-06/C7

(continued)

P25

Insert: 5.6.5 B3

Unit 2 only:

88-24, Peach Bottom Atomic Power Station Unit 2 Vessel Surveillance Materials Testing and Fracture Toughness Analysis, Revision 1, December 1991, and approved by the NRC in [ ].

Unit 3 only:

SASR 90-50, Peach Bottom Atomic Power Station Unit 3 Vessel Surveillance Materials Testing and Fracture Toughness Analysis, June 1990, and approved by the NRC in [ ].

B

Insert 5.7.1 & 5.7.2
Page 1 of 4

5.0 ADMINISTRATIVE CONTROLS

5.7 High Radiation Areas

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 <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>

a. Each accessible entryway to such an area shall be barricaded and conspicuously posted as a high radiation area. Such barricades may be ~~breached during periods of~~ 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 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"), or

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, or

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

(continued)

INSERT 5.7.1 # 5.7.2
Page 2 of 4

5.7 High Radiation Areas

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

4. A direct-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.

B

Except for individuals qualified in radiation protection procedures,

e. Entry into such areas shall be made only after dose rates in the area have been established and entry personnel are knowledgeable of them.

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

a. Each accessible 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 radiation protection personnel.

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

(continued)

INSERT 5.7.1 & 5.7.2
page 3 of 4

5.7 High Radiation Areas

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:

B

1. An alarming dosimeter with an appropriate alarm setpoint, or

2. A radiation monitoring device that continuously transmits dose rate or cumulative dose information 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, or

3. A direct-reading dosimeter and,

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

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

4. A radiation monitoring and indicating device in those cases where the options of Specifications 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.

(continued)

B

INSERT 5.1.1 & 5.7.2
Page 4 of 4

5.7 High Radiation Areas

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)

Except for individuals qualified in radiation protection procedures,

e. 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

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.

NON-BRACKETED PLANT SPECIFIC CHANGES (continued)

P_{10} This change modifies requirements for leak testing primary coolant sources outside containment to limit tests to the extent permitted by system design and radiological controls. This change is consistent with the PBAPS current Technical Specification requirements.

P_{11} This change to Section 5.5.4.e (old 5.4.2.4.e) modifies the requirement to determine cumulative dose from effluents such that only liquid effluents must be considered. This change is consistent with existing Technical Specification requirements.

P_{12} Not used. B

P_{13} The overtime limit requirements have been revised to delete the reference to the length of the work day "[8 or 12] hour day". However, the nominal 40 hour work week requirement will still be maintained. This wording is being deleted in order to provide more flexibility in shift scheduling to allow shifts up to 12 hours. The proposed change does not change the intent of the guidance of Generic Letter 82-16 with regards to the number of hours worked per week, and will ensure that routine use of heavy overtime will not be used.

P_{14} The proposed change will revise the requirement for the Senior Manager—Operations to hold a Senior Reactor Operator (SRO) license. The change will require the Senior Manager—Operations to either hold an SRO license or have held an SRO license on a similar BWR unit. However, shift personnel would continue to report to the Shift Managers who are required to be licensed as SROs for PBAPS in accordance with 10 CFR 50.54(m)(2), and who in turn report directly to the Senior Manager—Operations.

P_{15} Not used. B

NON-BRACKETED PLANT SPECIFIC CHANGES (continued)

P_{20} Specification 5.5.7.d demonstrates that the pressure drop across the filters and the charcoal filters is less than the specified pressure drop when tested at the specified system flow rate. Specification 5.5.7.d also referenced that the test would be performed in accordance with ASME N510-1989, Section 8.5.1. Section 8.5.1 of ASME N510-1989 is an airflow capacity test to assure that the maximum airflow rate can be achieved. As a result, the reference to ASME N510-1989, Section 8.5.1, has been deleted.

P_{21} Specification 5.5.7.f which requires a sample of the charcoal filter to be analyzed once per year to assure halogen removal efficiency of at least 99.5%. This requirement is being deleted by PBAPS Technical Specification Change Request 95-02 dated 2/10/95 from G.A.Hunger, Jr. (PECO Energy) to NRC. As such, Specification 5.5.7.f is also proposed to be deleted to achieve consistency with the proposed Technical Specification requirements for ventilation filter testing. A

P_{22} Specification 5.5.9.a which specifies new fuel oil requirements has been revised to allow for the verification of limits by the use of comparison to the supplier's certificate as approved in PBAPS Amendments 173 and 176 dated 4/23/93. The Bases for SR 3.8.3.3 have also been revised to allow for the verification of new fuel oil limits by the use of comparison to the supplier's certificate and acceptance criteria as approved in PBAPS Amendments 173 and 176 dated 4/23/93.

P_{23} During the development of the PBAPS ITS, the detail in NUREG-1433 regarding the limitations on the functional capability of the liquid and gaseous effluent treatment system was not incorporated since the limitations were not consistent with the CTS limitations on the use of these effluent treatment systems. NUREG-1433 Specification 5.7.2.7.g stated, "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." Doses from both liquid and gaseous effluent are required to be projected by NUREG-1433 Specification 5.7.2.7.g. However, CTS 3.8.C, Gaseous Effluents, does not require dose contributions from gaseous radioactive effluent to be projected to ensure the appropriate portions of the systems are used to reduce releases. Therefore, the PBAPS ITS Specification 5.5.4.f (which is equivalent to NUREG-1433 Specification 5.7.2.7.g) was developed to only require that the B

NON-BRACKETED PLANT SPECIFIC CHANGES

P_{23} (cont'd) Radioactive Effluent Controls Program include limitations on the functional capability and use of the liquid and gaseous effluent treatment systems and that these limitations shall be specified in the Offsite Dose Calculation Manual (ODCM).

Upon further review in response to NRC comments on PBAPS ITS 5.5.4.f, it was decided to revise proposed Specification 5.5.4.f to explicitly reflect the Applicability requirements of the CTS for liquid and gaseous effluent treatment systems and to reflect the ITS NUREG requirements to the extent possible without impacting the CTS requirements. The proposed wording is as follows:

> "Limitations on the functional capability and use of the liquid effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when projected doses averaged over one month would exceed 0.12 mrem to the total body or 0.4 mrem to any organ (combined total from the two reactors at the site)."

> "Limitations to ensure gaseous effluents shall be processed, prior to release, through the appropriate gaseous effluent treatment systems as described in the ODCM."

3

P_{24} CTS 4.9.A.1.2.d.1.d) utilizes the ASTM D4176-82 clear and bright test to provide a qualitative assessment of the acceptability of new diesel fuel oil with regard to water and sediment content. The ASTM clear and bright test is a visual check for evidence of water and particulate contamination performed after drawing a fuel oil sample for field testing. The visual check is accomplished by swirling the sample so a vortex is formed. Sediment and water will accumulate on the bottom of the container directly beneath the vortex and very fine suspended solids or water will render the product hazy. The ASTM clear and bright test should only be used for fuel oil meeting the color requirements of ASTM D4176-82 (ASTM color of 5 or less). ASTM D4176-82 does not recommend the clear and bright test be performed on fuels darker than ASTM 5 since the presence of free water or particulates could be obscured. The intentional addition of dyes to fuel oil by suppliers (such as to identify sulfur content) makes the fuel oil darker than ASTM 5 and results in the need to use another method for determining water and sediment content of the fuel oil. To address the method for determining the presence of water and sediment in new diesel fuel oil that has been

NON-BRACKETED PLANT SPECIFIC CHANGES

P_{24} (cont'd) dyed, the requirements of Specification 5.5.9 (Diesel Fuel Oil Testing Program) and the Bases for SR 3.8.3.3 are proposed to be revised to allow the use of the ASTM D975-81 water and sediment by centrifuge test in lieu of the ASTM D4176-82 clear and bright test. The Bases for SR 3.8.3.3 will also be revised to reflect the use of the ASTM water and sediment by centrifuge test when dyes have intentionally been added to new fuel oil.

This change provides an alternate test for verifying the acceptability of new fuel oil with regard to water and sediment content. Excessive water and sediment in diesel fuel oil could have an immediate detrimental impact on diesel engine combustion and as a result diesel generator OPERABILITY. The ASTM D975-81 water and sediment by centrifuge test provides a quantitative assessment of water and sediment content. The use of the ASTM water and sediment by centrifuge test ensures that excessive water and sediment content, in new diesel fuel oil that has been dyed, will be detected (and not obscured by the presence of the dye) prior to addition to the storage tanks. The sensitivity of the ASTM water and sediment by centrifuge test for water and sediment is not affected by the presence of dyes in the fuel oil. For fuel oil with dyes, the sensitivity for detection of water and sediment of the ASTM water and sediment by centrifuge test is better than that provided by the ASTM clear and bright test. The ASTM water and sediment by centrifuge test is also the same test performed to quantitatively determine water and sediment content within 31 days following sampling and addition (after the new fuel has been added to the storage tank) in accordance with Specification 5.5.9.b and the Bases for SR 3.8.3.3. Regulatory Guide 1.137, Fuel Oil Systems for Standby Diesel Generators, also identifies that the water and sediment by centrifuge test provides an acceptable method for ensuring the initial and continuing quality of diesel fuel oil with respect to water and sediment content. Therefore, this alternate test provides adequate assurance, prior to storage tank addition, that the water and sediment content of the new dyed fuel oil will maintain diesel generator OPERABILITY.

P_{25} The PTLR concept will not be used at PBAPS since an NRC approved methodology does not exist for PBAPS.

P23 The control rod must be isolated from both scram and normal insert and withdraw pressure.

P22 C21 also ~~cont'y~~ ... INSERT NEXT PAGE

BASES

ACTIONS

A.1, A.2, and A.3, and P22 (continued)

P23 and normal insert and withdraw pressure

Required Action in an orderly manner. Isolating the control rod from scram prevents damage to the CRDM. The control rod ~~can~~ should be isolated from scram ~~and~~ normal insert and withdraw pressure, ~~yet still~~ while maintaining cooling water to the CRD.

Condition A concurrent with

from discovery of THERMAL POWER greater than the low power setpoint (LPSP) of the RWM

Monitoring of the insertion capability of each withdrawn control rod must also be performed within 24 hours. SR 3.1.3.2 and SR 3.1.3.3 perform periodic tests of the control rod insertion capability of withdrawn control rods. Testing each withdrawn control rod ensures that a generic problem does not exist. The allowed Completion Time of 24 hours provides a reasonable time to test the control rods, considering the potential for a need to reduce power to perform the tests. ~~Required Action A.2 is modified by a Note, which states that the requirement is not applicable when, below~~ the actual ~~low power setpoint~~ (LPSP) of the RWM, since the notch insertions may not be compatible with the requirements of rod pattern control (LCO 3.1.6) and the RWM (LCO 3.3.2.1).

P11 Insert A.3

~~THERMAL POWER is less than or equal to~~

To allow continued operation with a withdrawn control rod stuck, an evaluation of adequate SDM is also required within 72 hours. Should a DBA or transient require a shutdown, to preserve the single failure criterion, an additional control rod would have to be assumed to fail to insert when required. Therefore, the original SDM demonstration may not be valid. The SDM must therefore be evaluated (by measurement or analysis) with the stuck control rod at its stuck position and the highest worth OPERABLE control rod assumed to be fully withdrawn.

The allowed Completion Time of 72 hours to verify SDM is adequate, considering that with a single control rod stuck in a withdrawn position, the remaining OPERABLE control rods are capable of providing the required scram and shutdown reactivity. Failure to reach MODE 4 is only likely if an additional control rod adjacent to the stuck control rod also fails to insert during a required scram. Even with the postulated additional single failure of an adjacent control rod to insert, sufficient reactivity control remains to reach and maintain MODE 3 conditions (Ref. 5).

(continued)

Insert A.3 (P11)

This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." The Required Action A.3 Completion Time only begins upon discovery ~~that~~ of Condition A concurrent with THERMAL POWER is greater than

B

BASES

ACTIONS (continued)

B.1 ~~and B.2~~ P22

~~C21 INSERT FROM PREVIOUS PAGE~~ P22

~~P23 The control rod must be isolated from both scram and normal insert and withdraw pressure.~~

P22 ~~C22~~ 2 P22

must be P22

With two or more withdrawn control rods stuck, ~~the stuck control rods should be isolated from scram pressure within 2 hours and~~ the plant brought to MODE 3 within 12 hours. ~~The allowed Completion Time of 1 hour is acceptable, considering the low probability of a CRDA occurring during this interval.~~ P22 The occurrence of more than one control rod stuck at a withdrawn position increases the probability that the reactor cannot be shut down if required. Insertion of all insertable control rods eliminates the possibility of an additional failure of a control rod to insert. 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.

B

C.1 and C.2

With one or more control rods inoperable for reasons other than being stuck in the withdrawn position, operation may continue, provided the control rods are fully inserted within 3 hours and disarmed (electrically or hydraulically) within 4 hours. Inserting a control rod ensures the shutdown and scram capabilities are not adversely affected. The control rod is disarmed to prevent inadvertent withdrawal during subsequent operations. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. The control rods can be electrically disarmed by disconnecting power from all four directional control valve solenoids. Required Action C.1 is modified by a Note, which allows the RWM to be bypassed if required to allow insertion of the inoperable control rods and continued operation. LCO 3.3.2.1 provides additional requirements when the RWM is bypassed to ensure compliance with the CRDA analysis.

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

(continued)

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.8 Scram Discharge Volume (SDV) Vent and Drain Valves

BASES

P21

~~However~~, As discussed in Reference 1, ~~the~~ SDV vent and drain valves need not be considered primary containment isolation valves (PCIVs) for the Scram Discharge System.

(However, at PBAPS, these valves are considered PCIVs)

P21

BACKGROUND

The SDV vent and drain valves are normally open and discharge any accumulated water in the SDV to ensure that sufficient volume is available at all times to allow a complete scram. During a scram, the SDV vent and drain valves close to contain reactor water. The SDV is a volume of header piping that connects to each hydraulic control unit (HCU) and drains into an instrument volume. There are two SDVs (headers) and a common ~~two~~ instrument volume~~s, each~~ that receives all ~~receiving approximately one half~~ of the control rod drive (CRD) discharges. The ~~two~~ instrument volume ~~are~~ is connected to a common drain line with two valves in series. Each header is connected to a common vent line with two valves in series for a total of four vent valves. The header piping is sized to receive and contain all the water discharged by the CRDs during a scram. The design and functions of the SDV are described in Reference ~~1~~ 3. P5 P21

APPLICABLE SAFETY ANALYSES

The Design Basis Accident and transient analyses assume all of the control rods are capable of scramming. The acceptance criteria for the SDV vent and drain valves are that they operate automatically to ~~:~~ close

P22

a. ~~Close~~ during scram to limit the amount of reactor coolant discharged so that adequate core cooling is maintained and offsite doses remain within the limits of 10 CFR 100 (Ref. ~~2~~ 3) P5 ~~; and~~

~~b. Open on scram reset to maintain the SDV vent and drain path open so that there is sufficient volume to accept the reactor coolant discharged during a scram.~~

C12

Isolation of the SDV can also be accomplished by manual ~~(control switch)~~ closure of the SDV valves. Additionally, the discharge of reactor coolant to the SDV can be terminated by scram reset or closure of the HCU manual isolation valves. For a bounding leakage case, the offsite doses are well within the limits of 10 CFR 100 (Ref. ~~2~~ 3) P5, and adequate core cooling is maintained (Ref. 13). P5 The SDV vent and drain valves allow continuous drainage of the SDV during

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.17

modified per GWE-14 c.1

~~This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. This test may be performed in one measurement or in overlapping segments, with verification that all components are tested. The RPS RESPONSE TIME acceptance criteria are included in Reference 10.~~

~~As noted, neutron detectors 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 an 18 month STAGGERED TEST BASIS. The 18 month Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.~~

P15

Insert SR 3.3.1.1.18 Bases

B

REFERENCES

1. UFSAR, ~~Figure [ ]~~. Section 7.2
2. UFSAR, ~~Section [15.1.2]~~. Chapter 14
3. NEDO-23842, "Continuous Control Rod Withdrawal in the Startup Range," April 18, 1978.
4. ~~FSAR, Section [5.2.2]~~. NEDC-32183P, "Power Rerate Safety Analysis Report for Peach Bottom 2+3," dated May 1993.
5. UFSAR, Section ~~[15.1.38]~~. 14.6.2
6. UFSAR, Section ~~[6.3.3]~~. 14.5.4
7. FSAR, ~~Chapter [15]~~. Section 14.5.1
8. P. Check (NRC) letter to G. Lainas (NRC), "BWR Scram Discharge System Safety Evaluation," December 1, 1980.
9. NEDO-30851-P-A , "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.
10. ~~FSAR, Table [7.2-2]~~. MDE-87-0485-1 "Technical Specification Improvement Analysis for the Reactor Protection System for Peach Bottom Atomic Power Station, units 2 and 3," October 1987.
11. UFSAR, Section 7.2.3.9

P2

B

Insert SR 3.3.1.1.18 Bases (P15)

SR 3.3.1.1.18

This SR ensures that the individual channel response times are maintained less than or equal to the original design value. The RPS RESPONSE TIME acceptance criterion is included in Reference 11.

RPS RESPONSE TIME tests are conducted on a 24 month Frequency. The 24 month Frequency is consistent with the PBAPS 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 occurrences.

18

BASES

ACTIONS (continued)

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

A.1

When one or more Functions have one required channel that is inoperable, the required inoperable channel must be restored to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channels (or, in the case of a Function that has only one required channel, other non-Regulatory Guide 1.97 instrument channels to monitor the Function), the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

Modified by C.26 P5 5.6.7 6 P5 B

If a channel has not been restored to OPERABLE status in 30 days, this Required Action specifies initiation of action in accordance with Specification ~~5.9.2.c, "Special Reports,"~~ which requires a written report ~~approved by the [onsite review committee]~~ C11 C11 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 action is appropriate in lieu of a shutdown requirement, since alternative actions are identified before loss of functional capability, and given the likelihood of plant conditions that would require information provided by this instrumentation.

C.1

When one or more Functions have two required channels that are inoperable (i.e., two channels inoperable in the same

(continued)

BASES

ACTIONS (continued)

P5 E ~~D.1~~

Pc is P6 P6 the

For the majority of Functions in Table 3.3.3.1-1, if ~~any~~ the Required Action and associated Completion Time of Condition C ~~or D are~~ is not met, the plant must be brought to a MODE in which the LCO not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

P5 F ~~E.1~~ modified by TSTF-09 c.16 P5 5.6.~~7~~ 6 C11

Since alternate means of monitoring ~~water level and primary containment area~~ drywell high range radiation have been developed and tested, the Required Action is not to shut down the plant, but rather to follow the directions of Specification ~~5.9.2.c.~~ 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.

SURVEILLANCE REQUIREMENTS

P5 ~~The following SRs apply to each PAM instrumentation Function in Table 3.3.3.1-1.~~

SR 3.3.3.1.1

C12

Performance of the CHANNEL CHECK once every 31 days ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel against 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

(continued)

BASES INSERT B 3.3-221 P1

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis. for Unit 2/Unit 3 LOP instrumentation P1

<For unit 2> <For unit 3>

1. 4.~~16~~ kV Emergency Bus Undervoltage (Loss of Voltage)

P1 When both offsite sources are lost, a loss of voltage condition P1 on a 4.~~16~~ kV emergency bus indicates that ~~offsite power may be completely lost to~~ the respective emergency bus ~~and~~ P1 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 the Loss of Voltage Function Allowable Values (loss of voltage with a short time delay)~~. P1 This ensures that adequate power will be available to the required equipment.

P5 ~~The Bus Undervoltage Allowable Values are low enough to prevent inadvertent power supply transfer, but high enough to ensure that 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.~~

P1 The single ~~Two~~ channel~~s~~ of 4.~~16~~ kV Emergency Bus Undervoltage (Loss of Voltage) Function per associated emergency bus ~~are~~ is only required to be OPERABLE when the associated DG and offsite circuit are P5 ~~is~~ required to be OPERABLE. This ensures P1 ~~to ensure that~~ no single instrument failure can preclude the ~~DG function~~ start of three of four DGs. (~~Two~~ One P1 channel~~s~~ input~~s~~ to each of the ~~three~~ Four P1 DGs.) Refer to LCO 3.8.1, "AC Sources—Operating," and 3.8.2, "AC Sources—Shutdown," for Applicability Bases for the DGs. B

P5 3, 4, 5. ~~2.~~ 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, available power may be insufficient for starting large ECCS 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 there is no offsite power to the buses ~~the voltage on the bus drops below the Degraded Voltage Function Allowable Values~~.

P1 This transfer will occur only if the voltage of the primary and alternate power sources drop below the Degraded Voltage Function Allowable Values (degraded voltage with a time delay) and the source breakers trip which causes the bus undervoltage relay to initiate the DGs. This ensures that adequate power will be available to the required equipment.

(continued)

BASES

P5 3., 4., 5.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) (continued)

P1 INSERT B 3.3-222

~~(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 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.

P1 (one channel per source)

This ensures no single instrument failure can preclude the start of three of four DGs (Each logic inputs to each of the four DGs).

(Function 2, 3, 4, and 5) P5 and offsite circuit are P5

Two channels per 3 of ~~4.16 kV Emergency Bus Undervoltage (Degraded Voltage)~~ Function per associated bus are only required to be OPERABLE when the associated DG ~~is~~ required to be OPERABLE. ~~to ensure that no single instrument failure can preclude the DG function. (Two channels input to each of the three emergency buses and DGs.)~~ Refer to LCO 3.8.1 and LCO 3.8.2 for Applicability Bases for the DGs.

ACTIONS

(Note 1) P6

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 ~~trains~~ division (C10), 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.

P5 INSERT ~~A.1/B.1 and B.2~~ A.1 and B.1

INSERT C.1 P5

C P5 ~~A.1~~

~~Required Action C.1 is applicable to the Loss of Voltage, the Degraded Voltage Low Setting, and the Degraded Voltage LOCA Functions (Functions 1, 2, and 4, respectively).~~ P5

In this Condition P5

~~With one or more channels of a Function inoperable,~~ the affected Function ~~is~~ may P3 be not capable of performing the intended function and the potential consequences associated with the inoperable channel(s) are greater than those resulting from Condition A or Condition B P5. Therefore, only 1 hour is allowed to restore the inoperable

(continued)

P5

Insert A.1 and B.1 (page 1 of 6)

< Unit 2 Version >

A.1

Pursuant to LCO 3.0.6, the AC Sources—Operating ACTIONS would not have to be entered even if the LOP instrumentation inoperability resulted in an inoperable offsite circuit. Therefore, the Required Action of Condition A is modified by a Note to indicate that when performance of a Required Action results in the inoperability of an offsite circuit, Actions for LCO 3.8.1, "AC Sources—Operating," must be immediately entered. A Unit 2 offsite circuit is considered to be inoperable if it is not supplying or not capable of supplying (due to loss of autotransfer capability) at least three Unit 2 4 kV emergency buses when the other offsite circuit is providing power or capable of supplying power to all four Unit 2 4 kV emergency buses. A Unit 2 offsite circuit is also considered to be inoperable if the Unit 2 4 kV emergency buses being powered or capable of being powered from the two offsite circuits are all the same when at least one of the two circuits does not provide power or is not capable of supplying power to all four Unit 2 4 kV emergency buses. Inoperability of a Unit 3 offsite circuit is the same as described for a Unit 2 offsite circuit, except that the circuit path is to the Unit 3 4 kV emergency buses required to be OPERABLE by LCO 3.8.7, "Distribution Systems - Operating." The Note allows Condition A to provide requirements for the loss of a LOP instrumentation channel without regard to whether an offsite circuit is rendered inoperable. LCO 3.8.1 provides appropriate restriction for an inoperable offsite circuit.

B

(P5)

Insert A.1 and B.1 (continued)

(page 2 of 6)

< Unit 3 Version >

A.1

Pursuant to LCO 3.0.6, the AC Sources—Operating ACTIONS would not have to be entered even if the LOP instrumentation inoperability resulted in an inoperable offsite circuit. Therefore, the Required Action of Condition A is modified by a Note to indicate that when performance of a Required Action results in the inoperability of an offsite circuit, Actions for LCO 3.8.1, "AC Sources—Operating," must be immediately entered. A Unit 3 offsite circuit is considered to be inoperable if it is not supplying or not capable of supplying (due to loss of autotransfer capability) at least three Unit 3 4 kV emergency buses when the other offsite circuit is providing power or capable of supplying power to all four Unit 3 4 kV emergency buses. A Unit 3 offsite circuit is also considered to be inoperable if the Unit 3 4 kV emergency buses being powered or capable of being powered from the two offsite circuits are all the same when at least one of the two circuits does not provide power or is not capable of supplying power to all four Unit 3 4 kV emergency buses. Inoperability of a Unit 2 offsite circuit is the same as described for a Unit 3 offsite circuit, except that the circuit path is to the Unit 2 4 kV emergency buses required to be OPERABLE by LCO 3.8.7, "Distribution Systems - Operating." The Note allows Condition A to provide requirements for the loss of a LOP instrumentation channel without regard to whether an offsite circuit is rendered inoperable. LCO 3.8.1 provides appropriate restriction for an inoperable offsite circuit.

B

(P5)

Insert A.1 and B.1 (continued) (page 3 of 6)

B

A.1 (continued)

Required Action A.1 is applicable when one 4 kV emergency bus has one or two required Function 3 (Degraded Voltage High Setting) channels inoperable or when one 4 kV emergency bus has one or two required Function 5 (Degraded Voltage Non-LOCA) channels inoperable. In this Condition, the affected Function may not be capable of performing its intended function automatically for these buses. However, the operators would still receive indication in the control room of a degraded voltage condition on the unaffected buses and a manual transfer of the affected bus power supply to the alternate source could be made without damaging plant equipment. Therefore, Required Action A.1 allows 14 days to restore the inoperable channel(s) to OPERABLE status or place the inoperable channel(s) in trip. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore design trip capability to the LOP instrumentation, and allow operation to continue. Alternatively, 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 DG initiation), Condition D must be entered and its Required Action taken.

The 14 day Completion Time is intended to allow time to restore the channel(s) to OPERABLE status. The Completion Time takes into consideration the diversity of the Degraded Voltage Functions, the capabilities of the remaining OPERABLE LOP Instrumentation Functions on the affected 4 kV emergency bus and on the other 4 kV emergency buses (only one 4 kV emergency bus is affected by the inoperable channels), the fact that the Degraded Voltage High Setting and Degraded Voltage Non-LOCA Functions provide only a marginal increase in the protection provided by the voltage monitoring scheme, the low probability of the grid operating in the voltage band protected by these Functions, and the ability of the operators to perform the Functions manually.

Insert A.1 and B.1 (continued) PS (page 4 of 6)

< Unit 2 Version >

B.1

Pursuant to LCO 3.0.6, the AC Sources - Operating ACTIONS would not have to be entered even if the LOP instrumentation inoperability resulted in an inoperable offsite circuit. Therefore, the Required Action of Condition B is modified by a Note to indicate that when performance of a Required Action results in the inoperability of an offsite circuit, Actions for LCO 3.8.1, "AC Sources - Operating," must be immediately entered. A Unit 2 offsite circuit is considered to be inoperable if it is not supplying or not capable of supplying (due to loss of autotransfer capability) at least three Unit 2 4 kV emergency buses when the other offsite circuit is providing power or capable of supplying power to all four Unit 2 4 kV emergency buses. A Unit 2 offsite circuit is also considered to be inoperable if the Unit 2 4 kV emergency buses being powered or capable of being powered from the two offsite circuits are all the same when at least one of the two circuits does not provide power or is not capable of supplying power to all four Unit 2 4 kV emergency buses. Inoperability of a Unit 3 offsite circuit is the same as described for a Unit 2 offsite circuit, except that the circuit path is to the Unit 3 4 kV emergency buses required to be OPERABLE by LCO 3.8.7, "Distribution Systems - Operating." This allows Condition B to provide requirements for the loss of a LOP instrumentation channel without regard to whether an offsite circuit is rendered inoperable. LCO 3.8.1 provides appropriate restriction for an inoperable offsite circuit.

B

P5

B

Insert A.1 and B.1 (continued)

(Pg 5 of 6)

< Unit 3 Version >

B.1

Pursuant to LCO 3.0.6, the AC Sources – Operating ACTIONS would not have to be entered even if the LOP instrumentation inoperability resulted in an inoperable offsite circuit. Therefore, the Required Action of Condition B is modified by a Note to indicate that when performance of a Required Action results in the inoperability of an offsite circuit, Actions for LCO 3.8.1, "AC Sources – Operating," must be immediately entered. A Unit 3 offsite circuit is considered to be inoperable if it is not supplying or not capable of supplying (due to loss of autotransfer capability) at least three Unit 3 4 kV emergency buses when the other offsite circuit is providing power or capable of supplying power to all four Unit 3 4 kV emergency buses. A Unit 3 offsite circuit is also considered to be inoperable if the Unit 3 4 kV emergency buses being powered or capable of being powered from the two offsite circuits are all the same when at least one of the two circuits does not provide power or is not capable of supplying power to all four Unit 3 4 kV emergency buses. Inoperability of a Unit 2 offsite circuit is the same as described for a Unit 3 offsite circuit, except that the circuit path is to the Unit 2 4 kV emergency buses required to be OPERABLE by LCO 3.8.7, "Distribution Systems - Operating." This allows Condition B to provide requirements for the loss of a LOP instrumentation channel without regard to whether an offsite circuit is rendered inoperable. LCO 3.8.1 provides appropriate restriction for an inoperable offsite circuit.

(P5)

Insert A.1 and B.1 (continued) (Page 6 of 6)

<u>B.1</u> (continued)

Required Action B.1 is applicable when two 4 kV emergency buses have one required Function 3 (Degraded Voltage High Setting) channel inoperable, or when two 4 kV emergency buses have one required Function 5 (Degraded Voltage Non-LOCA) channel inoperable, or when one 4 kV emergency bus has one required Function 3 channel inoperable and a different 4 kV emergency bus has one required Function 5 channel inoperable. In this Condition, the affected Function may not be capable of performing its intended function automatically for these buses. However, the operators would still receive indication in the control room of a degraded voltage condition on the unaffected buses and a manual transfer of the affected bus power supply to the alternate source could be made without damaging plant equipment. Therefore, Required Action B.1 allows 24 hours to restore the inoperable channels to OPERABLE status or place the inoperable channels in trip. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore design trip capability to the LOP instrumentation, and allow operation to continue. Alternatively, 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 DG initiation), Condition D must be entered and its Required Action taken.

The 24 hour Completion Time is intended to allow time to restore the channel(s) to OPERABLE status. The Completion Time takes into consideration the diversity of the Degraded Voltage Functions, the capabilities of the remaining OPERABLE LOP Instrumentation Functions on the affected 4 kV emergency buses and on the other 4 kV emergency buses (only two 4 kV emergency buses are affected by the inoperable channels), the fact that the Degraded Voltage High Setting and Degraded Voltage Non-LOCA Functions provide only a marginal increase in the protection provided by the voltage monitoring scheme, the low probability of the grid operating in the voltage band protected by these Functions, and the ability of the operators to perform the Functions manually.

B

(P5)

Insert C.1 (page 1 of 2)

B

< Unit 2 Version >

C.1

Pursuant to LCO 3.0.6, the AC Sources - Operating ACTIONS would not have to be entered even if the LOP Instrumentation inoperability resulted in an inoperable offsite circuit. Therefore, the Required Action of Condition C is modified by a Note to indicate that when performance of the Required Action results in the inoperability of an offsite circuit, Actions for LCO 3.8.1, "AC Sources - Operating," must be immediately entered. A Unit 2 offsite circuit is considered to be inoperable if it is not supplying or not capable of supplying (due to loss of autotransfer capability) at least three Unit 2 4 kV emergency buses when the other offsite circuit is providing power or capable of supplying power to all four Unit 2 4 kV emergency buses. A Unit 2 offsite circuit is also considered to be inoperable if the Unit 2 4 kV emergency buses being powered or capable of being powered from the two offsite circuits are all the same when at least one of the two circuits does not provide power or is not capable of supplying power to all four Unit 2 4 kV emergency buses. Inoperability of a Unit 3 offsite circuit is the same as described for a Unit 2 offsite circuit, except that the circuit path is to the Unit 3 4 kV emergency buses required to be OPERABLE by LCO 3.8.7, "Distribution Systems - Operating." The Note allows Condition C to provide requirements for the loss of a LOP instrumentation channel without regard to whether an offsite circuit is rendered inoperable. LCO 3.8.1 provides appropriate restriction for an inoperable offsite circuit.

Required Action C.1 is applicable when one or more 4 kV emergency buses have one or more required Function 1, 2, or 4 (the Loss of Voltage, the Degraded Voltage Low Setting, and the Degraded Voltage LOCA Functions, respectively) channels inoperable, or when one 4 kV emergency bus has one required Function 3 (Degraded Voltage High Setting) channel and one required Function 5 (Degraded Voltage Non-LOCA) channel inoperable, or when any combination of three or more required Function 3 and Function 5 channels are inoperable.

(Ps)

Insert C.1 (continued) (Page 2 of 2)

B

< Unit 3 Version >

C.1

Pursuant to LCO 3.0.6, the AC Sources — Operating ACTIONS would not have to be entered even if the LOP Instrumentation inoperability resulted in an inoperable offsite circuit. Therefore, the Required Action of Condition C is modified by a Note to indicate that when performance of the Required Action results in the inoperability of an offsite circuit, Actions for LCO 3.8.1, "AC Sources — Operating," must be immediately entered. A Unit 3 offsite circuit is considered to be inoperable if it is not supplying or not capable of supplying (due to loss of autotransfer capability) at least three Unit 3 4 kV emergency buses when the other offsite circuit is providing power or capable of supplying power to all four Unit 3 4 kV emergency buses. A Unit 3 offsite circuit is also considered to be inoperable if the Unit 3 4 kV emergency buses being powered or capable of being powered from the two offsite circuits are all the same when at least one of the two circuits does not provide power or is not capable of supplying power to all four Unit 3 4 kV emergency buses. Inoperability of a Unit 2 offsite circuit is the same as described for a Unit 3 offsite circuit, except that the circuit path is to the Unit 2 4 kV emergency buses required to be OPERABLE by LCO 3.8.7, "Distribution Systems - Operating." The Note allows Condition C to provide requirements for the loss of a LOP instrumentation channel without regard to whether an offsite circuit is rendered inoperable. LCO 3.8.1 provides appropriate restriction for an inoperable offsite circuit.

Required Action C.1 is applicable when one or more 4 kV emergency buses have one or more required Function 1, 2, or 4 (the Loss of Voltage, the Degraded Voltage Low Setting, and the Degraded Voltage LOCA Functions, respectively) channels inoperable, or when one 4 kV emergency bus has one required Function 3 (Degraded Voltage High Setting) channel and one required Function 5 (Degraded Voltage Non-LOCA) channel inoperable, or when any combination of three or more required Function 3 and Function 5 channels are inoperable.

C P5

BASES

ACTIONS C ~~B~~.1 (continued) P5

P1 design trip

the LOP instrumentation P1

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~~.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability ~~to accommodate a single failure (within the LOP instrumentation)~~, 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 DG initiation), Condition ~~C~~ D P5 must be entered and its Required Action taken.

based on the potential consequences associated with the inoperable channel(s) and P5

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

B

D P5
~~C~~.1

<For unit 2> <For unit 3>

SR 3.3.8.1.5 is applicable only to the Unit 3 Unit 2 LOP instrumentation. P1

If any Required Action and associated Completion Time are not met, the associated Function is not capable of performing the intended function. Therefore, the associated DG(s) is declared inoperable immediately. This requires entry into applicable Conditions and Required Actions of LCO 3.8.1 and LCO 3.8.2, which provide appropriate actions for the inoperable DG(s).

P1

: (a) for Function 1,

<For unit 2> <For unit 3>

P1 Unit 2 Unit 3

SURVEILLANCE REQUIREMENTS

The loss of Function for one DG or undervoltage transfer capability for one 4kV emergency bus for this short period is appropriate since only three of four DGs are required to start within the required times and because there is no appreciable impact on risk. Also,

As noted at the beginning of the SRs, the SRs for each Unit 2 Unit 3 LOP instrumentation Function are located in the SRs column of Table 3.3.8.1-1.

also P1

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 2 hours provided : (a) for Function 1, the associated Function maintains ~~DG~~ initiation capability for three DGs; and (b) for Functions 2, 3, 4, 5 the associated Function maintains undervoltage transfer capability for three 4 kV emergency buses. Upon completion of the Surveillance, or expiration of the 2 hour allowance, the channel must be

P1 for three DGs; and (b) for Functions 2, 3, 4, 5 the associated Function maintains undervoltage transfer capability for three 4 kV emergency buses.

(continued)

NON-BRACKETED PLANT SPECIFIC CHANGES (continued)

P_{13} The APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY section of the Bases describing the LPCI-Reactor Vessel Shroud Level-Level 0 states "An accompanying permissive from drywell pressure (Function 2.e, Drywell Pressure-High (RHR Valves)) is required for the suppression pool spray and drywell spray modes." This statement is proposed to be deleted from the Bases since the function, Drywell Pressure-High (RHR Valves), has been proposed to be relocated to a licensee-controlled document.

P_{14} The APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY section of the Bases describing the required combination of Core Spray pumps indicating high discharge pressure necessary for generating an ADS permissive has been revised. This revision is being proposed for consistency with the plant design of these Functions as described in the BACKGROUND section of Bases B 3.3.5.1.

P_{15} The RPS RESPONSE TIME testing requirements have been revised to reflect the PBAPS current licensing basis described in CTS 3.1.A and 4.1.A.

P1 and average power range monitor/rod block monitor Technical Specification/maximum extended load line limit

BASES

APPLICABLE SAFETY ANALYSES (continued)

P1 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~~ (Ref. 3 and 4). P1 P2 A

The transient analyses of Chapter 15 14 of the FSAR have also been performed for single recirculation loop operation (Ref. 3 5) and demonstrate sufficient flow coastdown characteristics to maintain fuel thermal margins during the abnormal operational transients analyzed provided the MCPR and APLHGR limits (power-dependent APLHGR multipliers, $MAPFAC_p$, and flow-dependent APLHGR multipliers, $MAPFAC_f$) requirements are modified. During single recirculation loop operation, modification to the Reactor Protection System (RPS) 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~~ limits for single loop operation are specified in the COLR. The APRM flow biased ~~simulated THERMAL POWER setpoint~~ High Scram Allowable Value is in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation." P1 P2 P3 A

INSERT ASA P5

Recirculation loops operating satisfies Criterion 2 of the NRC Policy Statement.

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. ~~With the limits specified in SR 3.4.1.1 not met, the recirculation loop with the lower flow must be considered not in operation. With~~ only one recirculation loop in operation, modifications to the required ~~APLHGR limits (LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"),~~ APLHGR limits (power- and flow-dependent APLHGR multipliers, $MAPFAC_p$ and $MAPFAC_f$, respectively of LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"), MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)"), and APRM Flow Biased ~~Simulated Thermal Power—High setpoint~~ High Scram Allowable Value (LCO 3.3.1.1) ~~may~~ must be applied to allow continued operation consistent with the assumptions of References ~~3~~ 5 and 6. P1 P2 P3

P5 In addition, the core flow expressed as a function of THERMAL POWER must be in the "Unrestricted" region of Figure 3.4.1-1, "THERMAL POWER Versus Core Flow Stability Regions." Alternatively, with

(continued)

Insert LCO Bases for 3.4.1 P3

B

P3

Insert LCO Bases for 3.4.1

The LCO is modified by a Note which allows up to 12 hours before having to put in effect the required modifications to required limits after a change in the reactor operating conditions from two recirculation loops operating to single recirculation loop operation. If the required limits are not in compliance with the applicable requirements at the end of this period, the associated equipment must be declared inoperable or the limits "not satisfied," and the ACTIONS required by nonconformance with the applicable specifications implemented. This time is provided due to the need to stabilize operation with one recirculation loop, including the procedural steps necessary to limit flow in the operating loop, limit total THERMAL POWER, monitor for excessive APRM and local power range monitor (LPRM) neutron flux noise levels; and the complexity and detail required to fully implement and confirm the required limit modifications.

B

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.~~11~~ 9 RCS Pressure and Temperature (P/T) Limits
P3

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.

P3 P3

The ~~PTLR~~ Specification contains P/T limit curves for heatup, cooldown, and inservice leakage and hydrostatic testing, and ~~data for~~ also limits the maximum rate of change of reactor coolant temperature. The ~~heatup~~ criticality curve provides limits for both heatup and criticality.

P3 B B

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.

P6

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~~ abnormal operational ~~occurrences~~ transients, and system hydrostatic tests. It mandates the use of the ASME Code, Section III, Appendix G (Ref. 2).

P1

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 with ~~ASTM E 185~~ the UFSAR (Ref. 3) and Appendix H of 10 CFR 50 (Ref. 4). The operating P/T limit curves will be adjusted,

P1

(continued)

BASES

BACKGROUND (continued)

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 stress 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.

P1 60°F above the adjusted reference temperature of the reactor vessel material in the region that is controlling (reactor vessel flange region)

The 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 leakage and hydrostatic testing.~~

P6 reactor pressure vessel

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. ASME Code, Section XI, Appendix E (Ref. 6), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

P2 P3 5 <for Unit 2 only> and 8 <for Unit 2 only>

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. Reference 7 ~~establishes the methodology for determining the P/T limits~~. Since the P/T limits are not derived from any DBA, there are no acceptance

P3 approved the curves and limits specified in this section

P6 < reactor pressure vessel

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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.

LCO C7

The elements of this LCO ~~are~~: P3

a. RCS pressure ~~,~~ and temperature ~~, and heatup or cooldown rate~~ are within the limits specified in ~~the PTLR~~ Figures 3.4.9-1 and 3.4.9-2, and heatup or cooldown rates are ≥ 100°F during RCS heatup, cooldown, and inservice leak and hydrostatic testing; P3 1

b. The temperature difference between the reactor vessel bottom head coolant and the reactor pressure vessel (RPV) coolant is ~~within the limit of the PTLR~~ ≤ 145°F P3 during recirculation pump startup, and during increases in THERMAL POWER or loop flow when operating at low THERMAL POWER or loop flow; P12 1

c. The temperature difference between the reactor coolant in the respective recirculation loop and in the reactor vessel ~~meets the limit of the PTLR~~ is ≤ 50°F P3 during recirculation pump startup; 1

d. RCS pressure and temperature are within the criticality limits specified in ~~the PTLR~~ Figure 3.4.9-3 C7 P3, prior to achieving criticality; and 1

e. The reactor vessel flange and the head flange temperatures are ~~within the limits of the PTLR~~ > 70°F P3 when tensioning the C7 reactor vessel head bolting studs ~~are tensioned~~. C7

These limits define allowable operating regions and permit a large number of operating cycles while also providing a wide margin to nonductile failure.

The rate of change of temperature limits controls the thermal gradient through the vessel wall and ~~are~~ is used as inputs for calculating the heatup, cooldown, and inservice leakage 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. P9

Violation of the limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses

(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 stress 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~~ 212°F. 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 beltline. P3

SURVEILLANCE REQUIREMENTS

P3 SR 3.4.~~10~~ 9.1

Verification that operation is within ~~PTLR~~ 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 a reasonable time for assessment and correction of minor deviations. P3 B

Plant procedures specify the pressure and temperature points to be used during the performance of this surveillance P6

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.

This SR has been modified with a Note that requires this Surveillance to be performed only during system heatup and cooldown operations and inservice leakage and hydrostatic testing.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.~~10~~.2 9 P3

A separate limit is used when the reactor is approaching criticality. Consequently, the RCS pressure and temperature must be verified within the appropriate limits before withdrawing control rods that will make the reactor critical.

Performing the Surveillance within 15 minutes before control rod withdrawal for the purpose of achieving criticality provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the control rod withdrawal.

SR 3.4.~~10~~.3 and SR 3.4.~~10~~.4 9 P3 9

Differential temperatures within the applicable ~~PTLR~~ limits ensure that thermal stresses resulting from the startup of an idle recirculation pump will not exceed design allowances. In addition, compliance with these limits ensures that the assumptions of the analysis for the startup of an idle recirculation loop (Ref. 8) ~~are~~ satisfied. P3 B

9 for Unit 2 only P2 B

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.~~10~~.4 is to compare the temperatures of the operating recirculation loop ~~and the idle loop.~~ 9 P3

SR 3.4.~~10~~.3 ~~has~~ been modified by a Note that requires the Surveillance to be ~~performed~~ only in MODES 1, 2, 3, and 4. ~~with reactor steam dome pressure ≥ 25 psig.~~ In MODE 5, the overall stress on limiting components is lower. Therefore, ΔT limits are not required. P3 9 and SR 3.4.9.4 have met P7 B3

P7
The Note also states the SR is only required to be met during a recirculation pump startup, since this is when the stresses occur.

P3 SR 3.4.~~10~~.5, SR 3.4.~~10~~.6, and SR 3.4.~~10~~.7 9 9 9

Limits on the reactor vessel flange and head flange temperatures are generally bounded by the other P/T limits

(continued)

BASES P3

SURVEILLANCE REQUIREMENTS

SR 3.4.~~10~~9.5, SR 3.4.~~10~~9.6, and SR 3.4.~~10~~9.7 (continued)

during system heatup and cooldown. However, operations 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 ≤ 80°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 temperature is within the limits specified ~~in the PTLR.~~ P3

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.

P6 INSERT SR

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.~~ UFSAR, Section 4.2.6 and Appendix K

P2

4. 10 CFR 50, Appendix H.
5. Regulatory Guide 1.99, Revision 2, May 1988.
6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.
7. ~~NEDO-21778-A, December 1978.~~ <for Unit 3 only>
8. 9 UFSAR, Section ~~[15.1.28]~~. 14.5.6.2 <for Unit 2 only>

~~SASR 89-24 / 90-53, Peach Bottom Atomic Power Station Unit 2 / Unit 3 Vessel Surveillance Materials Testing and Fracture Toughness Analysis, June 1990 / Revision 1, December 1991~~ ~~FOR UNIT 3~~ ~~FOR UNIT 2~~ P3

P2

<for Unit 2 only> 7. R. E Martin (NRC) letter to G.A. Hunger (PECo), Amendment No. 153 to Facility Operating License No. DPR-44 for the Peach Bottom Atomic Power Station Unit No. 2, dated October 25, 1989.

<for Unit 2 only> 7. <for Unit 3> 8. R.J. Clark (NRC) letter to G.J. Beck (PECo), Amendment Nos. 162 and 164 to Facility Operating License Nos DPR-44 and DPR-56 for the Peach Bottom Atomic Power Station Units Nos. 2 and 3, dated

(P6) INSERT SR

SR 3.4.9.5 is modified by a Note that requires the Surveillance to be performed only when tensioning the reactor vessel head bolting studs. SR 3.4.9.6 is modified by a Note that requires the Surveillance to be initiated 30 minutes after RCS temperature ≤ 80°F in Mode 4. SR 3.4.9.7 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 limits specified ~~in the PTLR~~. (P3)

BASES

BACKGROUND (continued)

P1

(if offsite power is available, A and C pumps in approximately 13 seconds, and B and D pumps in approximately 23 seconds, and if offsite power is not available, all pumps 6 seconds after

P13

the break, portions of the ECCS may be ineffective; however, the overall design is effective in cooling the core regardless of the size or location of the piping break. ~~Although no credit is taken in the safety analysis for the RCIC System, it performs a similar function as HPCI, but has reduced makeup capability. Nevertheless, it will maintain inventory and cool the core while the RCS is still pressurized following a reactor pressure vessel (RPV) isolation.~~

All ECCS subsystems are designed to ensure that no single active component failure will prevent automatic initiation and successful operation of the minimum required ECCS equipment.

The CS System (Ref. 1) is composed of two two 50% capacity P1 independent subsystems. Each subsystem consists of ~~2~~ motor driven ~~pumps~~ 5, a spray sparger above the core, and piping and valves to transfer water from the suppression pool to the sparger. The CS System is designed to provide cooling to the reactor core when reactor pressure is low. Upon receipt of an initiation signal, the CS pumps in both subsystems are automatically started ~~when~~ AC power is availab~~le~~. When the RPV pressure drops sufficiently, CS System flow to the RPV begins. A full flow test line is provided to route water from and to the suppression pool to allow testing of the CS System without spraying water in the RPV. P1

6

P1

(if offsite power is available, A and B pumps in approximately 2 seconds and C and D pumps in approximately 8 seconds, and, if offsite power is not available, all pumps immediately after AC power is available). Since one DG supplies power to an RHR pump in both units, the RHR pump breakers are interlocked between units to prevent operation of an RHR pump from both units on one DG and potentially overloading the affected DG.

INSERT Bases 3.5-2

LPCI is an independent operating mode of the RHR System. There are two LPCI subsystems (Ref. 2), each consisting of two motor driven pumps and piping and valves to transfer water from the suppression pool to the RPV via the corresponding recirculation loop. The two LPCI subsystems can be interconnected via the ~~RHR System~~ LPCI cross tie valve; P1 however, the cross tie valve is maintained closed with its power removed to prevent loss of both LPCI subsystems during a LOCA. The LPCI subsystems are designed to provide core cooling at low RPV pressure. Upon receipt of an initiation signal, all four LPCI pumps are automatically started ~~(B pump immediately when AC power is available, and A, C, and D pumps approximately 10 seconds after AC power is available)~~. RHR System valves in the LPCI flow path are automatically positioned to ensure the proper flow path for water from the suppression pool to inject into the recirculation loops. When the RPV pressure drops sufficiently, the LPCI flow to the RPV, via the

(continued)

BASES

ACTIONS
(continued)

Modified by BWROG, C58

P16

C.1 and C.2

If the HPCI System is inoperable and the RCIC System is immediately verified to be OPERABLE, the HPCI 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 ADS. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Immediate verification of RCIC OPERABILITY is therefore required when HPCI is inoperable. This may be performed as an administrative check by examining logs or other information to determine if RCIC is out of service for maintenance or other reasons. It does not mean to perform the Surveillances needed to demonstrate the OPERABILITY of the RCIC System. If the OPERABILITY of the RCIC System cannot be immediately verified, however, Condition G 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 a reliability study cited in Reference ~~12~~ 9 13 and has been found to be acceptable through operating experience.

E

P7

D.1 and D.2

If any one low pressure ECCS injection/spray subsystem is inoperable in addition to an inoperable HPCI System, the inoperable low pressure ECCS injection/spray subsystem or the HPCI System must be restored to OPERABLE status within 72 hours. In this Condition, adequate core cooling is ensured by the OPERABILITY of the ADS and the remaining low pressure ECCS subsystems. However, the overall ECCS reliability is significantly reduced 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 both a high pressure system (HPCI) and a low pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the HPCI System or the low pressure ECCS injection/spray subsystem to OPERABLE status. This Completion Time is based on a reliability study cited in Reference ~~12~~ 9 13 and has been found to be acceptable through operating experience.

(continued)

BASES

LCO (continued)

manually realigned (remote or local) to the LPCI mode and is not otherwise inoperable. 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 low pressure 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 ≥ ~~23 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.

458 inches above reactor pressure vessel instrument zero (20 ft 11 inches

P1

and no operations with a potential for draining the reactor vessel (OPDRVs) in progress

P11

P11

The Automatic Depressurization System is not required to be OPERABLE during MODES 4 and 5 because the RPV pressure is ≤ ~~150~~ psig, and the CS System and the LPCI subsystems can provide core cooling without any depressurization of the primary system.

100

P5

B

The High Pressure Coolant Injection System is not required to be OPERABLE during MODES 4 and 5 since the low pressure ECCS injection/spray subsystems can provide sufficient flow to the vessel.

ACTIONS

A.1 and B.1

P10

an

If any one required low pressure ECCS injection/spray subsystem is inoperable, ~~the~~ inoperable subsystem must be restored to OPERABLE status in 4 hours. In this Condition, the remaining OPERABLE subsystem can provide sufficient vessel 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

(continued)

BASES

ACTIONS

A.1 and B.1 (continued)

the ECCS not being able to perform its intended function. The 4 hour Completion Time for restoring the required low pressure ECCS injection/spray subsystem to OPERABLE status is based on engineering judgment that considered the remaining available subsystem and the low probability of a vessel draindown event.

With the inoperable subsystem not restored to OPERABLE status in the required Completion Time, action must be immediately initiated 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. P11 B

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

With both of the required ECCS injection/spray subsystems inoperable, all coolant inventory makeup capability may be unavailable. Therefore, actions must immediately be initiated to suspend OPDRVs 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.

If at least one low pressure 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 ~~initiating immediate action to restore the following to OPERABLE status:~~ secondary containment is OPERABLE, one standby gas treatment subsystem for Unit 2 / Unit 3 ~~, and one isolation valve and associated instrumentation~~ are OPERABLE or other acceptable administrative controls to assure isolation capability) in each associated penetration flow path not isolated that is assumed to be isolated to mitigate radioactivity releases. OPERABILITY may be verified by an administrative check, or by examining logs or other information, to determine whether the components are out of service for maintenance or other reasons. ~~Verification does not require~~ It is not necessary to perform~~ing~~ the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the Surveillance may need to be performed to restore the component to

Secondary containment isolation capability (i.e.,

C6 C6 C6 C6 C6 C6 P9

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1 (continued)

10 CFR 50, Appendix J (Ref. 2), as modified by approved exemptions. This SR reflects the leakage rate testing requirements with respect to air lock leakage (Type B leakage tests). The acceptance criteria were established [during initial air lock and primary containment OPERABILITY testing]. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall primary containment leakage rate. The Frequency is required by 10 CFR 50, Appendix J (Ref. 2), as modified by approved exemptions. Thus, SR 3.0.2 (which allows Frequency extensions) does not apply.

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

SR 3.6.1.2.2

The air lock interlock mechanism is designed to prevent simultaneous opening of both doors in the air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident primary containment pressure, closure of either door will support primary containment OPERABILITY. Thus, the interlock feature supports primary containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous inner and outer door opening will not inadvertently occur. Due to the purely mechanical nature of this interlock, and given that the interlock ~~mechanism is~~ only challenged when primary containment ~~is entered~~, this test is only required to be performed upon ~~entering~~ primary containment, but is not required more frequently than 184 days when primary containment is de-inerted. The 184 day Frequency is based on engineering judgment and is

~~air lock~~

or exiting

an lock door is opened

STEr

B

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.2 (continued)

B.1

considered adequate in view of other administrative controls ~~[such as indications of interlock mechanism status,~~ available to operations personnel~~]~~.

REFERENCES

P2 5.2.3.4.5 B1

1. ~~U~~FSAR, Section ~~[3.8.2.8.2.2]~~.

2. 10 CFR 50, Appendix J.

P3

3. ~~FSAR, Section [6.2].~~ Letter G94-PEPR-183, Peach Bottom Improved Technical Specification Project Increased Drywell and Suppression Chamber Pressure Analytical Limits, from G.V. Kumar (GE) to A.A. Winter (PECo), August 23, 1994.

B

BASES

ACTIONS (continued)

inoperable due to a failed open test return valve). Note 4 ensures appropriate remedial actions are taken when the primary containment leakage limits are exceeded. Pursuant to LCO 3.0.6, these actions ~~are not~~ required even when the associated LCO is not met. Therefore, Notes 3 and 4 are added to ~~require that~~ the proper actions ~~are~~ taken.

would not be   be   C2

P10   P11

A.1 and A.2   P11

With one or more penetration flow paths with one PCIV inoperable [except for ~~purge valve~~ leakage not within limit], the affected penetration flow paths 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 a penetration isolated in accordance with Required Action A.1, the valve used to isolate the penetration should be the closest available valve to the primary containment. The Required Action must be completed within the 4 hour Completion Time (8 hours for main steam lines). The Completion Time 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.

inoperability due to   MSIV   C2 device

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration flow path(s) 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 valve manipulation. Rather, it involves verification ~~through a system walkdown~~, that those valves outside containment and capable of potentially being mispositioned are in the correct position. The Completion Time of "once

device C2   C2 devices

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

devices

C2

per 31 days for isolation devices outside primary containment" is appropriate because the valves 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 judgment and is considered reasonable in view of the inaccessibility of the valves and other administrative controls ensuring that valve misalignment is an unlikely possibility.

C2

device

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 the appropriate Required Actions.

C2

isolation devices

Required Action A.2 is modified by a Note that applies to valves and blind flanges 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 ~~of these valves~~, once they have been verified to be in the proper position, is low.

C2

B

~~P1~~ P10

except due to MSIV leakage not within limit

B.1

With one or more penetration flow paths with two PCIVs inoperable, 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.

B

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

P14

~~[except during [illegible] limits]~~

B

ACTIONS (continued)

C.1 and C.2

With one or more penetration flow paths with one PCIV inoperable, 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 ~~the [4] hours Completion Time~~. The Completion Time of ~~[4]~~ hours 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 instrument and the small pipe diameter of penetration (hence, reliability) to act as a penetration isolation boundary and the small pipe diameter of the affected penetrations. ~~In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration 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. The Completion Time of once per 31 days for verifying each affected penetration is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.~~

C2

for lines other than excess flow check valve (EFCV) lines and 12 hours for EFCV lines

INSERT D

P10

Condition C is modified by a Note indicating that this Condition is only applicable to penetration flow paths with only one PCIV. For penetration flow paths with two PCIVs, Conditions A and B provide the appropriate Required Actions.

Required Action C.2 is modified by a Note that applies to valves and blind flanges 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 of these valves, once they have been verified to be in the proper position, is low.

(continued)

BASES

, hydrostatic leakage ~~P4~~ P10

ACTIONS (continued)

D.1

any MSIV

With ~~the secondary containment bypass~~ leakage rate not within limit, the assumptions of the safety analysis are not met. Therefore, the leakage must be restored to within limit within ~~4~~ 8 hours. 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~~ 8 hour Completion Time is reasonable considering the time required to restore the leakage by isolating the penetration, the fact that MSIV closure will result in isolation of the main steam line and a potential for plant shutdown, and the relative importance of ~~secondary containment bypass~~ MSIV leakage to the overall containment function.

P10

B.

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

Also modified by NRC-02, C15 and BWR-15, C16.

~~In the event one or more containment purge valves are not within the purge valve leakage limits, purge valve leakage must be restored to within limits or the affected penetration must be isolated. The method of isolation must be by the use of a least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a [closed and de-activated automatic valve, closed manual valve, and blind flange]. A purge valve with resilient seals utilized to satisfy Required Action E.1 must have been demonstrated to meet the leakage requirements of SR 3.6.1.3.7. The specified Completion Time is reasonable, considering that one containment purge valve remains closed (refer to the Note to SR 3.6.1.3.1) so that a gross breach of containment does not exist.~~

~~In accordance with Required Action E.2, this penetration flow path must be verified to be isolated on a periodic basis. The periodic verification is necessary to ensure that containment penetrations required to be isolated following an accident, which are no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not~~

(continued)

BASES

SURVEILLANCE REQUIREMENTS

B1

SR 3.6.1.3.1 (continued)

~~in order to effect repairs to that valve. This allows one purge valve to be opened without resulting in a failure of the Surveillance and resultant entry into the ACTIONS for this purge valve, provided the stated restrictions are met. Condition E must be entered during this allowance, and the valve opened only as necessary for effecting repairs. Each purge valve in the penetration flow path may be alternately opened, provided one remains sealed closed, if necessary, to complete repairs on the penetration.~~

~~[The SR is modified by a Note stating that primary containment purge valves are only required to be sealed closed in MODES 1, 2, and 3. If a LOCA inside primary containment occurs in these MODES, the purge valves may not be capable of closing before the pressure pulse affects systems downstream of the purge valves or the release of radioactive material will exceed limits prior to the closing of the purge valves. At other times when the purge valves are required to be capable of closing (e.g., during handling of irradiated fuel), pressurization concerns are not present and the purge valves are allowed to be open.]~~

P5

INSERT E

[SR 3.6.1.3.2] 3 P6

P3 and exhaust

C2

This SR ensures that the primary containment purge valves are closed as required or, if open, open for an allowable reason. ~~[The SR is also modified by a Note (Note 1), stating that primary containment purge valves are only required to be closed in MODES 1, 2, and 3. If a LOCA inside primary containment occurs in these MODES, the purge valves may not be capable of closing before the pressure pulse affects systems downstream of the purge valves, or the release of radioactive material will exceed limits prior to the purge valves closing. At other times when the purge valves are required to be capable of closing (e.g., during handling of irradiated fuel), pressurization concerns are not present and the purge valves are allowed to be open.]~~ The SR is modified by a Note (Note 2) stating that the SR is not required to be met when the purge valves are open for the stated reasons. The Note states that these valves may be opened for inerting, de-inerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. The

If a purge valve is open in violation of this SR, the valve is considered inoperable & Condition A applies.

P11

If the open valve is known to have excessive leakage when closed, Condition E applies

P14

1 P10

and exhaust P3

B

(continued)

DISCUSSION OF CHANGES TO NUREG-1433
BASES SECTION 3.6--CONTAINMENT SYSTEMS

BRACKETED PLANT SPECIFIC CHANGES

B_1 Brackets removed and optional wording preferences revised or deleted, and/or plant specific number(s) inserted to reflect appropriate plant specific requirements.

GENERIC CHANGES

C_1 The secondary containment has no specific leakage limits. Therefore, modifications have been made to refer to the boundary, and not its limits or leak tightness. These changes were approved in BWR-15, C9.

C_2 Additional information was added, information deleted, and/or changes made to clarify and/or improve the Bases. These changes were approved in BWR-14, C1 (including Rev. 1), C2, and C6, BWR-15, C2, C5 (including Rev. 1), C6, C8, C9, C10, C11, C14, C15, C17, C18, C19 (Rev. 1), and C22, and BWR-16, C20, C22, C23 (including Rev. 1), and C24.

C_3 This SR is not required to be performed during a plant outage and will not impose a potential for unplanned transient. This change was approved in BWR-16, C28.

C_4 Changes to the Bases made for consistency with the Specification. This change was approved in BWR-4, C7 and C8.

C_5 Not used.

C_6 This sentence was added to provide clarity. This change was approved in BWR-16, C15, Revision 1.

C_7 Typographical error corrected. This change was approved in NRC-02, C15.

C_8 The reason the Note is acceptable has been provided. This change was approved in BWR-16, C22.

C_9 This is deemed to be excessive. With its deletion sufficiently detailed Bases remain. This change was approved in BWR-16, C26.

C_{10} Editorial corrections and enhancements. Also certain Bases improvements/additions for consistency with the Specification. This change was approved in BWR-16, C23.

NON-BRACKETED PLANT SPECIFIC CHANGES (continued)

P_9 Discussion was added and changes made to the Bases to reflect the changes made to the Specification. Action A in the Specification was changed to add both CAD subsystems which would allow 30 days if one or both CAD subsystems are inoperable. This is consistent with current licensing basis (NRC SER dated 7/13/79; Amendments 58 for Units 2 and 3).

P_{10} Changes to the Bases were made to be consistent with the Specifications.

P_{11} Bases revised for enhanced clarity.

P_{12} Bases revised to be consistent with PBAPS specific licensing basis approved in Amendment Nos. 127 and 130 for Units 2 and 3, respectively.

P_{13} As documented in NUREG-0661, Mark I Containment Long-Term Program Safety Evaluation Report, there is no suppression pool temperature limit that prevents (i.e., avoids) chugging. Chugging refers to the unsteady condensation process which occurs late in the blowdown when the vent flow rates are low. Therefore, the pool temperature influences but does not prevent the occurrence of chugging.

P_{14} Changes to the Bases provided by BWR-15, C19 were not fully incorporated since the only leakage in this LCO is MSIV leakage. Therefore, the Bases specifically refers to this type of leakage and does not discuss other types of leakage. B

P_{15} Changes to the Bases provided by BWR-16, C5 were not adopted since these valves are not required to be Operable in Modes other than 1, 2, and 3. Thus the Note (and the Bases description) are not needed.

P_{16} Inadvertent actuation of the Suppression Pool Spray System is not the main concern for depressurizing the drywell; a LOCA inside the drywell is the main concern. Therefore, this section has been reworded to place the emphasis on the proper reason.

P_{17} This discussion reflects the addition of a new Surveillance Requirement replacing the one in brackets from the Specification. The Surveillance Requirement was added to verify each suppression pool spray nozzle is unobstructed every 10 years.

(P1) INSERT B 3.8-4 #1

n OPERABLE <FOR UNIT 2>

A qualified Unit 2 offsite circuit consists of the incoming breaker and disconnect to the startup and emergency auxiliary transformer, the respective circuit path to the emergency auxiliary transformer, and the circuit path to at least three Unit 2 4 kV emergency buses including feeder breakers to the three Unit 2 4 kV emergency buses. A qualified Unit 3 offsite circuit's requirements are the same as the Unit 2 circuit's requirements, except that the circuit path, including the feeder breakers, is to the Unit 3 4 kV emergency buses required to be OPERABLE by LCO 3.8.7, "Distribution Systems—Operating."

n OPERABLE

If at least one of the two circuits does not provide power or is not capable of providing power to all four Unit 2 4 kV emergency buses, then the Unit 2 4 kV emergency buses that each circuit powers or is capable of powering can not all be the same (i.e., two feeder breakers on one Unit 2 4 kV emergency bus can not be inoperable).

n OPERABLE <For Unit 3>

A qualified Unit 3 offsite circuit consists of the incoming breaker and disconnect to the startup and emergency auxiliary transformer, the respective circuit path to the emergency auxiliary transformer, and the circuit path to at least three Unit 3 4 kV emergency buses including feeder breakers to the three Unit 3 4 kV emergency buses. A qualified Unit 2 offsite circuit's requirements are the same as the Unit 3 circuit's requirements, except that the circuit path, including the feeder breakers, is to the Unit 2 4 kV emergency buses required to be OPERABLE by LCO 3.8.7, "Distribution Systems—Operating."

n OPERABLE

If at least one of the two circuits does not provide power or is not capable of providing power to all four Unit 3 4 kV emergency buses, then the Unit 3 4 kV emergency buses that each circuit powers or is capable of powering can not all be the same (i.e., two feeder breakers on one Unit 3 4 kV emergency bus can not be inoperable).

(Pu) INSERT B 3.8-10 #2

B.4.2.1 and B.4.2.2

The 33 kV Conowingo Tie-Line using a separate 33/13.8 kV transformer, can be used to supply the circuit normally supplied by startup and emergency auxiliary transformer no. 2. While not a qualified circuit, this alternate source is a direct tie to the Conowingo Hydro Station ~~and~~ that provides a highly reliable source of power because: the line and transformers at both ends of the line are dedicated to the support of PBAPS; the tie line is not subject to damage from adverse weather conditions; and, the tie line can be isolated from other parts of the grid when necessary to ensure its availability and stability to support PBAPS. The availability of this highly reliable source of offsite power permits an extension to the 7 day allowable out of service time for a DG. Therefore, prior to the time period that the normal 7 day allowable out of service time for a DG is exceeded, it is necessary to verify the availability of the Conowingo Tie-Line. The Conowingo Tie-Line is available and satisfies the requirements of Required Action B.4.2.1 if: 1) the tie-line is supplying power to PBAPS Unit 1; 2) manual breaker operation is available to tie power from the Unit 1/Conowingo Tie-Line to the startup and emergency auxiliary transformer no. 2; and 3) communications with the Conowingo control room is available to ensure that required equipment at Conowingo is available. The Completion Time for the restoration of the DG to OPERABLE status may not be extended beyond 7 days from the initial time that Condition B was entered (the time allowed by Required Action B.4.1) if Required Action B.4.2.1 is not satisfied within 7 days. If the status of the Conowingo Tie-Line changes after Required Action B.4.2.1 is initially met, such that the DG restoration time is now 7 days (per Required Action B.4.1), the 7 days begins upon discovery of failure to meet Required Action B.4.2.1. However, the total time to restore an inoperable DG cannot exceed 14 days (per the second Completion Time of Required Action B.4.1).

The availability of the Conowingo Tie-Line provides an additional source which permits operation to continue in Condition B for a period that should not exceed 30 days. In Condition B, the remaining OPERABLE DGs and the normal offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 30 day Completion Time takes into account the enhanced reliability and availability of offsite sources due to the Conowingo Tie-Line, the redundancy, capacity, and capability of the other remaining AC sources, reasonable time for repairs of the affected DG, and low probability of a DBA occurring during this period.

B

BASES

ACTIONS

C.1 and C.2 (continued)

severe than other combinations of two AC sources inoperable that involve one or more DGs inoperable. However, two factors tend to decrease the severity of this degradation level:

a. The configuration of the redundant AC electrical power system that remains available is not susceptible to a single bus or switching failure; and

b. The time required to detect and restore an unavailable offsite power source is generally much less than that required to detect and restore an unavailable onsite AC source.

P4 two or more

With ~~both~~ of the ~~required~~ offsite circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

B P4 all but

P4 P1 all

According to Regulatory Guide 1.93 (Ref. 6), with the available offsite AC sources two less than required by the LCO, operation may continue for 24 hours. If ~~two~~ offsite sources are restored within 24 hours, unrestricted operation may continue. If ~~only~~ one offsite source is restored within 24 hours, power operation continues in accordance with Condition A.

all but P4

D.1 and D.2

PC Sw Operating

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no AC source to ~~one~~ ~~ESF~~ bus, ACTIONS for LCO 3.8.~~9~~, "Distribution Systems—Operating," must be immediately entered. This

P1 4 kV emergency bus

CB any

7 P4

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.1 (continued)

and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source and that appropriate independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

SR 3.8.1.2 and SR 3.8.1.7

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

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs have been modified by a Note (Note 2 for SR 3.8.1.2 and Note 1 for SR 3.8.1.7) to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period and followed by a warmup prior to loading.

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

B4

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

PE

to SR 3.8.1.2

P1 10 P1 10

SR 3.8.1.7 requires that, at a 184 day Frequency, the DG starts from standby conditions and achieves required voltage and frequency within ~~12~~ 10 seconds. The ~~12~~ 10 second start requirement supports the assumptions in the design basis LOCA analysis of UFSAR, Section ~~[6.3]~~ 8.5 (Ref. ~~12~~ 10). The ~~12~~ 10 second start requirement is not applicable to SR 3.8.1.2

Insert WSTS-5

C30

P1 10 P2 B2 P2

B

(continued)

C30

Insert WSTS-5

The minimum voltage and frequency stated in the SR are those necessary to ensure the DG can accept DBA loading while maintaining acceptable voltage and frequency levels. Stable operation at the nominal voltage and frequency values is also essential to establishing DG OPERABILITY, but a time constraint is not imposed. This is because a typical DG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not damped out by load application. This period may extend beyond the 10 second acceptance criteria and could be a cause for failing the SR. In lieu of a time constraint in the SR, PBAPS will monitor and trend the actual time to reach steady state operation as a means of ensuring there is no voltage regulator or governor degradation which could cause a DG to become inoperable.

B

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

(see Note 3 of SR 3.8.1.2), when a modified start procedure as described above is used. If a modified start is not used, the ~~12~~ 10 second start requirement of SR 3.8.1.7 applies.

P1 P2

P4 INSERT B 3.8-17

Since SR 3.8.1.7 ~~does~~ requires a ~~12~~ 10 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This procedure is the intent of Note 1 of SR 3.8.1.2.

The normal 31 day Frequency for SR 3.8.1.2 ~~(see Table 3.8.1-1, "Diesel Generator Test Schedule")~~ is consistent with Regulatory Guide 1.9 (Ref. 3). The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. ~~7~~ 5). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

P4 P2

SR 3.8.1.3

P1 a load approximately equivalent to that corresponding to the continuous rating.

This Surveillance verifies that the DGs are capable of synchronizing and accepting ~~greater than or equal to the equivalent of the maximum expected accident loads~~. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

Insert DG load P1

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor between [0.8 lagging] and [1.0]. The [0.8] value is the design rating of the machine, while [1.0] is an operational limitation ~~[to ensure circulating currents are minimized]~~. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. B3 B

The normal 31 day Frequency for this Surveillance ~~(see Table 3.8.1-1)~~ is consistent with Regulatory Guide 1.9 (Ref. 3). P4

(continued)

(P.1)

Insert DG load

This Surveillance verifies, indirectly, that the DGs are capable of synchronizing and accepting loads equivalent to post accident loads. The DGs are tested at a load approximately equivalent to their continuous duty rating, even though the post accident loads exceed the continuous rating. This is acceptable because regular surveillance testing at post accident loads is injurious to the DG, and imprudent because the same level of assurance in the ability of the DG to provide post accident loads can be developed by monitoring engine parameters during surveillance testing. The values of the testing parameters can then be qualitatively compared to expected values at post accident engine loads. In making this comparision it is necessary to consider the engine parameters as interrelated indicators of remaining DG capacity, rather than independent indicators. The important engine parameters to be considered in making this comparision include, fuel rack position, scavenging air pressure, exhaust temperature and pressure, engine output, jacket water temperature, and lube oil temperature. With the DG operating at or near continuous rating and the observed values of the above parameters less than expected post accident values, a qualitative extrapolation which shows the DG is capable of accepting post accident loads can be made without requiring deterimental testing.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

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

P1 C12

The Frequency of 24 ~~[18~~ months~~]~~ ~~is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(1)~~, takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

B4 P1

This SR is modified by ~~three~~ two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs shall be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. ~~Note 3 acknowledges that~~ credit may be taken for unplanned events that satisfy this SR.

C9 C9

P5
INSERT B 3.8-24

P5
Consistent with Regulatory Guide 1.9 (Ref. 3), paragraph C.2.2.5,

[SR 3.8.1.12

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (~~[12]~~ 10 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥ [5] minutes. The [5] minute period provides sufficient]

B4

Insert WSTS-5
C30

(continued)

B

C 3

Insert WSTS-5

The minimum voltage and frequency stated in the SR are those necessary to ensure the DG can accept DBA loading while maintaining acceptable voltage and frequency levels. Stable operation at the nominal voltage and frequency values is also essential to establishing DG OPERABILITY, but a time constraint is not imposed. This is because a typical DG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not damped out by load application. This period may extend beyond the 10 second acceptance criteria and could be a cause for failing the SR. In lieu of a time constraint in the SR, PBAPS will monitor and trend the actual time to reach steady state operation as a means of ensuring there is no voltage regulator or governor degradation which could cause a DG to become inoperable.

B

BASES

SURVEILLANCE REQUIREMENTS

B1

SR 3.8.1.13 (continued)

c. Performance of the SR, or failure of the SR, will not cause, or result in, an AOO with attendant challenge to plant safety systems.

SR 3.8.1.14

P5 Consistent with

90% to 100% of P1

B 1.9 P2 3 P2 C.2.2.9 P5 this Surveillance

Regulatory Guide ~~1.108~~ (Ref. ~~9~~), paragraph ~~2.a.(3)~~, requires demonstration ~~once per [18 months]~~ that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours—22 hours of which is at a load equivalent to the continuous rating of the DG, and 2 hours of which is at a load equivalent to 110% of the continuous duty rating of the DG. ~~Plant Hatch has taken an exception to this requirement and performs the 2 hour run at the 2000 hour rating (2100 kW).~~ The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelube and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

P1 duty P1 105% to

P1

P1 Insert DG load

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed using a power factor ≤ ~~[0.9]~~. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could experience. A load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

0.89 B4

B

24 month B4

The ~~[18 month]~~ Frequency ~~is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(3)~~; takes into consideration plant conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths.

P1 P2

Modified by BWOG-05, C.1

This Surveillance has been modified by three Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the limit do not invalidate the test. The reason for Note 2 is that during operation with the reactor critical, performance of this Surveillance could cause perturbations to the electrical distribution systems

L1

(continued)

P.

Insert DG load

This Surveillance verifies, indirectly, that the DGs are capable of synchronizing and accepting loads equivalent to post accident loads. The DGs are tested at a load approximately equivalent to their continuous duty rating, even though the post accident loads exceed the continuous rating. This is acceptable because regular surveillance testing at post accident loads is injurious to the DG, and imprudent because the same level of assurance in the ability of the DG to provide post accident loads can be developed by monitoring engine parameters during surveillance testing. The values of the testing parameters can then be qualitatively compared to expected values at post accident engine loads. In making this comparision it is necessary to consider the engine parameters as interrelated indicators of remaining DG capacity, rather than independent indicators. The important engine parameters to be considered in making this comparision include, fuel rack position, scavenging air pressure, exhaust temperature and pressure, engine output, jacket water temperature, and lube oil temperature. With the DG operating at or near continuous rating and the observed values of the above parameters less than expected post accident values, a qualitative extrapolation which shows the DG is capable of accepting post accident loads can be made without requiring deterimental testing.

BASES

SURVEILLANCE REQUIREMENTS

(P4) SR 3.8.1.14 (continued)

modified by BWOG-05 C.1

~~that would challenge continued steady state operation and, as a result, plant safety systems.~~ ~~Note 3 acknowledges that credit may be taken for unplanned events that satisfy this SR.~~

(P4) INSERT B 3.8-28 #1

SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within ~~[12]~~ 10 (B4) seconds. The ~~[12]~~ second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The ~~[18 month]~~ 24 month (B4) Frequency ~~is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(5).~~ (P1) (P2)

Insert WSTS-5 (C30)

(P1) takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by ~~two~~ three (P4) Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The requirement that the diesel has operated for at least 2 hours at full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing.

(P4) INSERT B 3.8-28 #2

SR 3.6.1.16

(P5) Consistent with (P1) ~~As required by~~ Regulatory Guide ~~1.108~~ 1.9 (P2) (Ref. ~~9~~ 3 (P2)), paragraph ~~2.a.(6)~~ C.2.2.11 (P2), this Surveillance ensures that the manual synchronization and ~~automatic~~ load transfer from the DG to the offsite source can be made and that the DG can be returned to ready-to-load status when offsite power is restored. It also ensures that the auto-start logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready-to-load status when the DG is at rated speed and voltage, the output breaker is open and can receive an

(continued)

C30

Insert WSTS-5

The minimum voltage and frequency stated in the SR are those necessary to ensure the DG can accept DBA loading while maintaining acceptable voltage and frequency levels. Stable operation at the nominal voltage and frequency values is also essential to establishing DG OPERABILITY, but a time constraint is not imposed. This is because a typical DG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not damped out by load application. This period may extend beyond the 10 second acceptance criteria and could be a cause for failing the SR. In lieu of a time constraint in the SR, PBAPS will monitor and trend the actual time to reach steady state operation as a means of ensuring there is no voltage regulator or governor degradation which could cause a DG to become inoperable.

B

BASES

SURVEILLANCE REQUIREMENTS

P4

INSERT B.3.8-32 #1

SR 3.8.1.19 (continued) C9

This SR is modified by ~~three~~ two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. ~~Note 3 acknowledges that~~ credit may be taken for unplanned events that satisfy this SR.

C9

SR 3.8.1.20

C30

Insert WSTS-5 TP

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

B

8 P2

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 8), ~~paragraph 2.b, and Regulatory Guide 1.137 (Ref. 10), paragraph C.2.f.~~ C14 This SR is modified by ~~a~~ two Notes. The reason for ~~the~~ Note 1 is to P4 minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations.

P4 two

P4

INSERT B 3.8-32 #3

P4

INSERT B 3.8-32 #2

P4

~~Diesel Generator Test Schedule~~

~~The DG test schedule (Table 3.8.1-1) implements the recommendations of Revision 3 to Regulatory Guide 1.9 (Ref. 3). The purpose of this test schedule is to provide timely test data to establish a confidence level associated with the goal to maintain DG reliability at > 0.95 per test.~~

~~According to Regulatory Guide 1.9 (Ref. 3), Revision 3, each DG unit should be tested at least once every 31 days. Whenever a DG has experienced 4 or more valid failures in the last 25 valid tests, the maximum time between tests is~~

(continued)

C30

Insert WSTS-5

The minimum voltage and frequency stated in the SR are those necessary to ensure the DG can accept DBA loading while maintaining acceptable voltage and frequency levels. Stable operation at the nominal voltage and frequency values is also essential to establishing DG OPERABILITY, but a time constraint is not imposed. This is because a typical DG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not damped out by load application. This period may extend beyond the 10 second acceptance criteria and could be a cause for failing the SR. In lieu of a time constraint in the SR, PBAPS will monitor and trend the actual time to reach steady state operation as a means of ensuring there is no voltage regulator or governor degradation which could cause a DG to become inoperable.

B

Insert ACTIONS (P4)

The ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

B

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3,

B

INSERT 3.8.3 ACTIONS

C18

The Actions Table is modified by a Note indicating that separate condition entry is allowed for each DG. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable DG subsystem. Complying with the Required Actions for one inoperable DG subsystem may allow for continued operation, and subsequent inoperable DG subsystem(s) are governed by separate condition entry and application of associated Required Actions. 8

P5

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.2 (continued)

operation without the level reaching the manufacturer's recommended minimum level.

A 31 day Frequency is adequate to ensure that a sufficient lube oil supply is onsite, since DG starts and run time are closely monitored by the plant staff.

SR 3.8.3.3

(of new fuel oil prior to addition to the storage tanks P5)

The tests ~~listed below~~ are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between ~~receipt~~ (the sample (and corresponding results) P5) of new fuel and ~~conducting the tests~~ to (addition of new fuel oil to the storage tanks P5) exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4054-[ ] (D4057 81 C5 C19 B4) (Ref. 6) (as discussed in Reference 7 P15);

b. Verify in accordance with the tests specified in ASTM D975-[ ] (81 B4) (Ref. 6) that the sample has an absolute specific gravity at 60/60°F of ≥ 0.83° and ≤ 0.89° or an API gravity at 60°F of ≥ 27° and ≤ 39° (if specific gravity was not determined by comparison with the supplier's certification) P12, a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes, and a flash point of ≥ 125°F; ~~and~~ (C4)

(P1) c. Verify ~~[illegible]~~ ~~[illegible]~~ D1298-80 (Ref. 6) in accordance with tests specified in ASTM that the sample has; and

~~procedures based on~~ P15 ~~(procedures based on)~~

(d) ~~c~~. Verify that the new fuel oil has a clear and bright appearance with proper color when tested in accordance with ASTM D4176-[ ] (82 B4) (Ref. 6) (as discussed in Reference 7; P15).

P1 ~~The intentional addition of dyes, for example due to sulfer content, does not constitute a failure of this requirement.~~

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

~~Within [31] days~~ (P5) following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other

or verify, in accordance with ASTM D975-81 (Ref. 6), that the sample has a water and sediment content ≤ 0.05 volume percent when dyes have been intentionally added to fuel oil (for example due to sulfer content). P15

(continued)

P12 or an API gravity of within 0.3° at 60°F when compared to the supplier's certificate

P12 , or an absolute specific gravity of within 0.0016 at 60/60°F when compared to the supplier's certificate,

P1S
as discussed in Reference 7

~~procedure based~~

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

C5 B4 B4
5 81

B5
Insert A

B4 B4
81 79
82

properties specified in Table 1 of ASTM D975-[ ] (Ref. 6) are met for new fuel oil when tested in accordance with ASTM D975-[ ] (Ref. 6), except that the analysis for sulfur may be performed in accordance with ASTM D1552-[ ] (Ref. 6) or ASTM D2622-[ ] (Ref. 6). The [31] day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate effect on DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs.

P1
except that the filters specified in ASTM D2276-78 (Sections 3.1.6 and 3.1.7) may have a nominal pore size up to three (3) microns.

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

P1S B
as discussed in Reference 7

~~procedure based on~~ P1
78 B4

Particulate concentrations should be determined in accordance with ASTM D2276-[ ] (Ref. 6), Method A. This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing. [For ~~those designs~~ the Peach Bottom Atomic Power Station design in which the total volume of stored fuel oil is contained in ~~two or more~~ four interconnected tanks, each tank must be considered and tested separately.]

B4

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

SR 3.8.3.4

P1
normal

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each DG is available. The normal system design requirements provide for a minimum of [five] engine starts ~~cycles~~ without recharging. ~~[A start cycle is defined by the DG vendor, but usually is measured in terms of time (seconds of cranking) or engine cranking speed.]~~ The pressure specified in this SR is intended to reflect the lowest value at which the [five] starts can be accomplished.

P1 B3

(continued)

BASES

SURVEILLANCE REQUIREMENTS

~~SR 3.8.3.6 (continued)~~

~~failure of this SR, provided that accumulated sediment is removed during performance of the Surveillance.~~

P4

REFERENCES

1. UFSAR, Section ~~[9.5.2]~~ 8. B4
2. Regulatory Guide 1.137.
3. ANSI N195, 1976.
4. UFSAR, Chapter ~~[6]~~. 14 B4
5. UFSAR, Chapter ~~[15]~~. P4
6. ASTM Standards: ~~D4054-[ ]~~; D975-~~[ ]~~ 81; D4176-~~[ ]~~ 82; D1522-~~[ ]~~ 79; D2622-~~[ ]~~ 82; and D2276-~~[ ]~~ 78. D4057-81; D1298-80; 5 P1 C12 B4
7. ~~ASME, Boiler and Pressure Vessel Code, Section XI.~~ P2 B4

7. Letter from G. A. Hunger (PECO Energy) to USNRC Document Control Desk; Peach Bottom Atomic Power Station Units 2 and 3, Supplement 7 to TSCR 93-16, Conversion to Improved Technical Specifications; dated May 24, 1995

P2 P.5 B

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.6

minimum

(P1)

Battery charger capability requirements are based on the design capacity of the chargers (Ref. 3). According to Regulatory Guide 1.32 (Ref. 8), the battery charger supply is required to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

(P1) requirement is based on the capacity to maintain the associated battery in its fully charged condition, and to restore the battery to its fully charged condition following the worst case design discharge while supplying normal steady state loads

(24) (B4) battery charger reliability and (P4) (3)

The Frequency is acceptable, given ~~the unit conditions required to perform the test and~~ the ~~other~~ administrative controls existing to ensure adequate charger performance during these ~~[18 months]~~ intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

(P4) modified by BWOG-09, C.1

This SR is modified by two Notes. The reason for Note 1 is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Note 2 is added to this SR to acknowledge that credit may be taken for unplanned events that satisfy the Surveillance.

SR 3.8.4.7

A battery service test is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length corresponds to the design duty cycle requirements~~, as specified in Reference 4.~~ (P2)

(P1) Insert B 3.8-56 SR 3.8.4.7

The Frequency of [18 months] is consistent with the recommendations of Regulatory Guide 1.32 (Ref. 8) and Regulatory Guide 1.129 (Ref. 9), which state that the battery service test should be performed during refueling operations or at some other outage, with intervals between tests not to exceed [18 months].

(C6) (C4) two

This SR is modified by ~~three~~ Notes. Note 1 ~~to SR 3.8.4.7~~ allows ~~the once per 60 months~~ performance of ~~SR 3.8.4.8~~ in

(P4) Either a modified performance discharge test or a performance discharge test (described in the Bases for SR 3.8.4.8) (P4) (P6)

(continued)

Insert ACTIONS (P4)

The ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

B

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3,

B

INSERT
B 3.8-61

C18

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC electrical power subsystems from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required. P5

P4

<For Unit 2>

SR 3.8.5.2

This Surveillance is provided to direct that the appropriate Surveillances for the required Unit 3 DC electrical power subsystems are governed by the Unit 3 Technical Specifications. Performance of the applicable Unit 3 Surveillances will satisfy Unit 3 requirements, as well as satisfying this Unit 2 Surveillance Requirement. The Frequency required by the applicable Unit 3 SR also governs performance of that SR for Unit 2.

As Noted, if Unit 3 is in MODE 4 or 5, or moving irradiated fuel assemblies in the secondary containment, the Note to Unit 3 SR 3.8.5.1 is applicable. This ensures that a Unit 2 SR will not require a Unit 3 SR to be performed, when the Unit 3 Technical Specifications exempts performance of a Unit 3 SR. (However, as stated in the Unit 3 SR 3.8.5.1 Note, while performance of an SR is exempted, the SR still must be met.)

C18

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC electrical power subsystems from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required. P5

<For Unit 3>

P4

SR 3.8.5.2

This Surveillance is provided to direct that the appropriate Surveillances for the required Unit 2 DC electrical power subsystems are governed by the Unit 2 Technical Specifications. Performance of the applicable Unit 2 Surveillances will satisfy Unit 2 requirements, as well as satisfying this Unit 3 Surveillance Requirement. The Frequency required by the applicable Unit 2 SR also governs performance of that SR for Unit 3.

As Noted, if Unit 2 is in MODE 4 or 5, or moving irradiated fuel assemblies in the secondary containment, the Note to Unit 2 SR 3.8.5.1 is applicable. This ensures that a Unit 3 SR will not require a Unit 2 SR to be performed, when the Unit 2 Technical Specifications exempts performance of a Unit 2 SR. (However, as stated in the Unit 2 SR 3.8.5.1 Note, while performance of an SR is exempted, the SR still must be met.)

B

<FOR UNIT 2 ONLY>

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.~~9~~ 7 P4 Distribution Systems—Operating

BASES

BACKGROUND P1

The onsite Class 1E AC and DC electrical power distribution system is divided into redundant and independent AC and DC ~~, and AC vital bus~~ electrical power distribution subsystems. P5 P1

The primary AC distribution system for Unit 2 consists of ~~three~~ two four 4.~~16~~ kV emergency ~~Engineered Safety Feature (ESF)~~ buses each having ~~an~~ offsite source~~s~~ of power as well as ~~a dedicated~~ its onsite emergency diesel generator (DG) source. Each 4.~~16~~ kV ~~ESF~~ emergency bus is ~~normally~~ connected to ~~a~~ normal source ~~startup auxiliary transformer (SAT) (2D)~~ of power via either emergency auxiliary transformer no. 2 or no. 3. During a loss of the normal supply of offsite power ~~source~~ to the 4.~~16~~ kV ~~ESF~~ emergency buses, the alternate supply breaker from ~~SAT 2C~~ the alternate supply of offsite power for the 4 kV emergency buses attempts to close. If all offsite sources are unavailable, the onsite emergency DGs supply power to the 4.~~16~~ kV ~~ESF~~ buses. (However, these supply breakers are not governed by this LCO; they are governed by LCO 3.8.1, "AC Sources-Operating.") P1 P5 P1

The secondary plant distribution system for Unit 2 includes ~~600~~ 480 VAC ~~emergency buses 2C and 2D and associated~~ load centers ~~, and transformers~~ E124, E224, E324, and E424. P1

~~The 120 VAC vital buses 2YV1, 2YV2, 2YV3, and 2YV4 are arranged in four load groups and are normally powered from DC. The alternate power supply for the vital buses is a Class 1E constant voltage source transformer powered from the same division as the associated inverter, and its use is governed by LCO 3.8.7, "Inverters—Operating." Each constant voltage source transformer is powered from AC.~~ P1 B

There are two independent 125/250 VDC ~~station service~~ electrical power distribution subsystems for Unit 2 ~~and three independent 125 VDC DG electrical power distribution subsystems~~ that support the necessary power for ESF functions. P1

P1 P5 INSERT BKGD ¶

The list of all required Unit 2 distribution buses is presented in Table B 3.8.~~9~~ 7 P4-1. P1

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the ~~F~~SAR, ~~Chapter [6] (Ref. 1) and~~ Chapter [~~15~~] 14 B4 (Ref. ~~2~~ 1 P3), assume Engineered Safety Feature (ESF) P2 P5 systems are OPERABLE. The P2

(continued)

<FOR UNIT 3 ONLY>

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.~~9~~ 7 P4 Distribution Systems—Operating

BASES

P1

BACKGROUND

The onsite Class 1E AC and DC electrical power distribution system is divided into redundant and independent AC and DC, ~~and AC vital bus~~ electrical power distribution subsystems. P1 P5

The primary AC distribution system for Unit 3 consists of ~~three~~ four 4.~~16~~ kV ~~Engineered Safety Feature (ESF)~~ emergency buses each having ~~an~~ two offsite sources of power as well as ~~a~~ its ~~dedicated~~ onsite diesel emergency generator (DG) source. Each 4.~~16~~ kV ~~ESF~~ emergency bus is ~~normally~~ connected to ~~a~~ normal source supply of ~~startup auxiliary transformer (SAT) (2D)~~ power via either emergency auxiliary transformer no. 2 or no. 3. During a loss of the normal offsite power ~~source~~ to the 4.~~16~~ kV ~~ESF~~ emergency buses, the alternate supply breaker from ~~SAT 2C~~ the alternate supply of offsite power for the 4 kV emergency buses attempts to close. If all offsite sources are unavailable, the onsite emergency DGs supply power to the 4.~~16~~ kV ~~ESF~~ buses. (However, these supply breakers are not governed by this LCO; they are governed by LCO 3.8.1 "AC Sources—Operating.") P1 P5 P1

The secondary plant distribution system for Unit 3 includes ~~600~~ 480 VAC ~~emergency buses 2C and 2D and associated~~ load centers ~~, and transformers~~ E134, E234, E334, and E434. P1

~~The 120 VAC vital buses 2YV1, 2YV2, 2YV3, and 2YV4 are arranged in four load groups and are normally powered from DC. The alternate power supply for the vital buses is a Class 1E constant voltage source transformer powered from the same division as the associated inverter, and its use is governed by LCO 3.8.7, "Inverters—Operating." Each constant voltage source transformer is powered from AC.~~ P1

There are two independent 125/250 VDC ~~station service~~ electrical power distribution subsystems for Unit 3 ~~and three independent 125 VDC DG electrical power distribution subsystems~~ that support the necessary power for ESF functions. P1

INSERT BKGD P1 P5

The list of all required Unit 3 distribution buses is presented in Table B 3.8.~~8~~ 7.1. P1 P4

B

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the ~~F~~ UFSAR, ~~Chapter [6] (Ref. 1) and~~ Chapter ~~[15]~~ 14 (Ref. ~~2~~ 1), assume ~~ESF~~ Engineered Safety Feature systems are OPERABLE. The P2 B4 P3 P2 P5

(continued)

INSERT LCO

(P4)

<For Unit 2>

In addition, since some components required by Unit 2 receive power through Unit 3 electrical power distribution subsystems (e.g., Standby Gas Treatment (SGT) System, emergency heat sink components, and DC control power for two of the four 4 kV emergency buses, as well as control power for two of the diesel generators), the Unit 3 AC and DC electrical power distribution subsystems needed to support the required equipment must also be OPERABLE. The Unit 3 electrical power distribution subsystems that may be required are listed in Unit 3 Table B 3.8.7-1.

<For Unit 3>

In addition, since some components required by Unit 3 receive power through Unit 2 electrical power distribution subsystems (e.g., Containment Atmospheric Dilution (CAD) System, Standby Gas Treatment (SGT) System, Emergency Service Water System, Main Control Room Emergency Ventilation (MCREV) System, and DC control power for two of the four 4 kV emergency buses, as well as control power for two of the diesel generators), the Unit 2 AC and DC electrical power distribution subsystems needed to support the required equipment must also be OPERABLE. The Unit 2 electrical power distribution subsystems that may be required are listed in Unit 2 Table B 3.~~4~~.7-1.

8

B

1

INSERT LCO - 2 (P5)

electrical power distribution component (i.e., bus, load center, or distribution panel)

electrical power distribution components

B

Based on the number of safety significant electrical loads associated with each ~~bus~~ electrical power distribution component (i.e., bus, load center, or distribution panel) listed in Table B 3.8.7-1, if one or more of the ~~buses~~ electrical power distribution components within a division (listed in Table 3.8.7-1) becomes inoperable, entry into the appropriate ACTIONS of LCO 3.8.7 is required. Other ~~buses~~ electrical power distribution components, such as motor control centers (MCC) and distribution panels, which help comprise the AC and DC distribution systems are not listed in Table B 3.8.7-1. The loss of electrical loads associated with these ~~buses~~ electrical power distribution components may not result in a complete loss of a redundant safety function necessary to shut down the reactor and maintain it in a safe condition. Therefore, should one or more of these ~~buses~~ electrical power distribution components become inoperable due to a failure not affecting the OPERABILITY of ~~a bus~~ an electrical power distribution component listed in Table B 3.8.7-1 (e.g., a breaker supplying a single MCC fails open), the individual loads on the ~~bus~~ electrical power distribution component would be considered inoperable, and the appropriate Conditions and Required Actions of the LCOs governing the individual loads would be entered. If however, one or more of these ~~buses~~ electrical power distribution components is inoperable due to a failure also affecting the OPERABILITY of ~~a bus~~ an electrical power distribution component listed in Table B 3.8.7-1 (e.g., loss of a 4 kV emergency bus, which results in de-energization of all ~~buses~~ electrical power distribution components powered from the 4 kV emergency bus), while these ~~buses~~ electrical power distribution components and individual loads are still considered inoperable, the Conditions and Required Actions of the LCO for the individual loads are not required to be entered, since LCO 3.0.6 allows this exception (i.e., the loads are inoperable due to the inoperability of a support system governed by a Technical Specification; the 4 kV emergency bus).

B

B

(P4)

INSERT A.1 & B.1 (pg 2 of 2)

1

<For Unit 3>

A.1

Pursuant to LCO 3.0.6, the DC Sources—Operating ACTIONS would not be entered even if the AC electrical power distribution subsystem inoperability resulted in de-energization of a required battery charger. Therefore, the Required Actions of Condition A are modified by a Note to indicate that when Condition A results in de-energization of a required Unit 2 battery charger, Actions for LCO 3.8.4 must be immediately entered. This allows Condition A to provide requirements for the loss of a Unit 2 AC electrical power distribution subsystem without regard to whether a battery charger is de-energized. LCO 3.8.4 provides the appropriate restriction for a de-energized battery charger.

If one or more of the required Unit 2 AC electrical power distribution subsystems are inoperable, and a loss of function has not occurred as described in Condition F, the remaining AC electrical power distribution subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure could, however, result in the loss of certain safety functions, continued power operation should not exceed 7 days. The 7 day Completion Time takes into account the capacity and capability of the remaining AC electrical power distribution subsystems, and is based on the shortest restoration time allowed for the systems affected by the inoperable AC electrical power distribution subsystem in the respective system Specification. B

B.1

If one of the Unit 2 DC electrical power distribution subsystems is inoperable, the remaining DC electrical power distribution subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure could, however, result in the loss of safety function, continued power operation should not exceed 12 hours. The 12 hour Completion Time reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power distribution subsystem and takes into consideration the importance of the Unit 2 DC electrical power distribution subsystem.

BASES

ACTIONS A.1 (continued) 3.8.7.a

~~this~~ LCO was initially not met, instead of at the time Condition ~~A~~ was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet ~~the~~ LCO indefinitely.

3.8.7.a

B.1

<Modified by BWR-03 C.1, R.1>

With one AC vital bus inoperable, the remaining OPERABLE AC vital buses are capable of supporting the minimum safety functions necessary to shut down the unit and maintain it in the safe shutdown condition. Overall reliability is reduced, however, since an additional single failure could result in the minimum required ESF functions not being supported. Therefore, the required AC vital bus must be restored to OPERABLE status within 2 hours.

Condition B represents one AC vital bus without power; potentially both the DC source and the associated AC source are nonfunctioning. In this situation the plant is significantly more vulnerable to a complete loss of all noninterruptible power. It is, therefore, imperative that the operator's attention focus on stabilizing the plant, minimizing the potential for loss of power to the remaining vital buses, and restoring power to the affected AC vital buses.

This 2 hour limit is more conservative than Completion Times allow for the majority of components that are without adequate vital AC power. Taking exception to LCO 3.0.2 for components without adequate vital AC power, that would have Required Action Completion Times shorter than 2 hours if declared inoperable, is acceptable because of:

a. The potential for decreased safety when requiring a change in plant conditions (i.e., requiring a shutdown) while not allowing stable operations to continue;

(continued)

Insert ACTIONS

P4

The ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

B

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3,

B

GENERIC CHANGES (continued)

C_{28} This change is consistent with approved generic change CEOG-01, C4.

C_{29} This change is consistent with approved generic change BWR-18, C2, Revision 0 and Revision 1.

C_{30} This change is consistent with generic change WSTS-5. B

NON-BRACKETED PLANT SPECIFIC CHANGES

P_1 These changes (including additions and deletions) reflect the PBAPS specific design, Licensing Basis, and/or nomenclature.

P_2 The reference(s) has been revised (including deletions) and/or renumbered to reflect the appropriate plant specific PBAPS Unit 2 and 3 reference(s).

P_3 This sentence has been deleted since a qualified offsite circuit is described in the Background and LCO section of the Bases and the UFSAR is referenced in the Background section.

P_4 This change was made to be consistent with changes made to the PBAPS Specifications (including adding Bases subsections to account for additional Actions and Surveillance Requirements).

P_5 Plant specific rewording, additional information/detail, grammatical, and/or punctuation changes were made to improve the clarity and readability of the Bases.

P_6 Generic change NRC-15, C1 added an allowance to SR 3.8.4.8 to perform a modified performance discharge test, instead of a performance discharge test. In addition, the Note to SR 3.8.4.7 was modified to only allow the newly added modified performance discharge test to be substituted for the service test once per 60 months. Bases were added to fully describe the newly added modified performance discharge test; however, the Bases description was added to SR 3.8.4.7, in the Note discussion. Normally, the SR that actually requires the test would have the Bases discussion, not an SR that has a Note describing that one SR can be substituted for another. Therefore, the Bases discussion added by NRC-15, C1 has been moved to the Bases for SR 3.8.4.8, since SR 3.8.4.8 is the SR that requires the modified performance test to be performed in the first place. Minor changes to the wording have also been made, as described in Items P_4 and P_8.

NON-BRACKETED PLANT SPECIFIC CHANGES (continued)

P_{10} The change added by BWR-08, C1, Revision 1 has not been adopted. Stating where the DC bus must be powered from is not needed. The DC bus is normally powered from either the associated battery or charger. The DC Sources Specification (LCO 3.8.4) precludes the cross-tieing of DC power supplies. If the DC bus was cross-tied to a different DC source, the DC source would be inoperable per LCO 3.8.4. In addition, a similar requirement was not added to the AC distribution Action Bases, even though they are capable of being cross-tied. Again, the AC Sources Specification (LCO 3.8.1) controls the cross-tie capability and requirements if cross-tied.

P_{11} PBAPS design has cross-tie capability for some of the distribution buses. The AC and DC sources Specifications allow cross-tieing of sources while shutdown. Therefore, cross-tie capability allowances for buses have also been provided.

P_{12} Specification 5.5.9.a which specifies new fuel oil requirements has been revised to allow for the verification of limits by the use of comparison to the supplier's certificate as approved in PBAPS Amendments 173 and 176 dated 4/23/93. The Bases for SR 3.8.3.3 have also been revised to allow for the verification of new fuel oil limits by the use of comparison to the supplier's certificate and acceptance criteria as approved in PBAPS Amendments 173 and 176 dated 4/23/93.

P_{13} For the Battery Performance Test or Modified Test, the PBAPS Bases state the Frequencies are in accordance with IEEE-450, 1987. However, the Frequency "24 months when battery has reached 85% of the expected life with capacity $\geq$ 100% of the manufacturer's rating" is not in accordance with IEEE-450, 1987. The previous wording was approved in Generic Change WOG-14, C1, and was based on a draft version of IEEE-450. As a result, the Bases have been modified to discuss a more appropriate basis for this Frequency. A

P_{14} Battery Cell Parameters support the operation of the DC electrical power subsystems and the Battery Cell Parameter Specification is required to be applicable during the same Modes and conditions as in Specification 3.8.4,"DC Sources-Operating," and Specification 3.8.5,"DC Sources-Shutdown". The same safety analyses discussions as those discussed in the Bases for Specification 3.8.4,"DC Sources-Operating," and Specification 3.8.5,"DC Sources-Shutdown" are also applicable to the Battery Cell Parameter Specification. As a result, the Bases for the Battery Cell Parameter Specification in the Applicable Safety Analyses Section have been revised accordingly.

NON-BRACKETED PLANT SPECIFIC CHANGES (continued)

P_{15} The requirements of the Diesel Fuel Oil Testing Program in Specification 5.5.9 were developed using the phrase "in accordance with procedures based on applicable ASTM Standards." This was done to provide the capability for justified variances between the ASTM Standards and the implementing procedures. The problem with the wording in NUREG-1433, "in accordance with applicable ASTM Standards," is that it invokes all the requirements of the documents referenced by the ASTM Standards and requires verbatim compliance. The documents referenced by the ASTM Standards, as well as the ASTM Standards, do not address issues related to verbatim compliance very well. As a result, while other approaches to meeting requirements should be acceptable (such as using new glassware for determining kinematic viscosity versus using glassware that has been cleaned in chromic acid), they are not acceptable since the ASTM Standards and the associated referenced documents do not include these approaches. However, the proposed wording, "in accordance with procedures based on applicable ASTM Standards," was not acceptable to the NRC. Following discussions between the NRC and PECO Energy regarding verbatim compliance with ASTM Standards, agreement was reached on the method to address the concern. Per the agreement, a letter to the NRC has been submitted identifying the PBAPS exceptions to the applicable ASTM Standards regarding diesel fuel oil testing to clarify what "in accordance with applicable ASTM Standards" means. The wording in Specification 5.5.9 regarding "procedures based on applicable ASTM Standards" has been revised to reflect the wording of NUREG-1433 (in accordance with applicable ASTM Standards). Specification 5.5.9.c, which specifies requirements for total particulate concentration, has also been revised to include a specific reference to the applicable ASTM Standard (in accordance with ASTM D2276, Method A). The Bases for SR 3.8.3.3 have also been revised to reference, for each ASTM Standard for which an exception was identified, the letter to the NRC identifying and justifying each of the PBAPS exceptions to the applicable ASTM Standards regarding diesel fuel oil testing. B

CTS 4.9.A.1.2.d.1.d) utilizes the ASTM D4176-82 clear and bright test to provide a qualitative assessment of the acceptability of new diesel fuel oil with regard to water and sediment content. The ASTM clear and bright test is a visual check for evidence of water and particulate contamination performed after drawing a fuel oil sample for field testing. The visual check is accomplished by swirling the sample so a vortex is formed. Sediment and water will accumulate on the bottom of the container directly beneath the vortex and very fine suspended solids or water will render the product hazy. The ASTM clear and bright test should only be used for fuel oil meeting

NON-BRACKETED PLANT SPECIFIC CHANGES

P_{15} (cont'd) the color requirements of ASTM D4176-82 (ASTM color of 5 or less). ASTM D4176-82 does not recommend the clear and bright test be performed on fuels darker than ASTM 5 since the presence of free water or particulates could be obscured. The intentional addition of dyes to fuel oil by suppliers (such as to identify sulfur content) makes the fuel oil darker than ASTM 5 and results in the need to use another method for determining water and sediment content of the fuel oil. To address the method for determining the presence of water and sediment in new diesel fuel oil that has been dyed, the requirements of Specification 5.5.9 (Diesel Fuel Oil Testing Program) and the Bases for SR 3.8.3.3 are proposed to be revised to allow the use of the ASTM D975-81 water and sediment by centrifuge test in lieu of the ASTM D4176-82 clear and bright test. The Bases for SR 3.8.3.3 will also be revised to reflect the use of the ASTM water and sediment by centrifuge test when dyes have intentionally been added to new fuel oil.

This change provides an alternate test for verifying the acceptability of new fuel oil with regard to water and sediment content. Excessive water and sediment in diesel fuel oil could have an immediate detrimental impact on diesel engine combustion and as a result diesel generator OPERABILITY. The ASTM D975-81 water and sediment by centrifuge test provides a quantitative assessment of water and sediment content. The use of the ASTM water and sediment by centrifuge test ensures that excessive water and sediment content, in new diesel fuel oil that has been dyed, will be detected (and not obscured by the presence of the dye) prior to addition to the storage tanks. The sensitivity of the ASTM water and sediment by centrifuge test for water and sediment is not affected by the presence of dyes in the fuel oil. For fuel oil with dyes, the sensitivity for detection of water and sediment of the ASTM water and sediment by centrifuge test is better than that provided by the ASTM clear and bright test. The ASTM water and sediment by centrifuge test is also the same test performed to quantitatively determine water and sediment content within 31 days following sampling and addition (after the new fuel has been added to the storage tank) in accordance with Specification 5.5.9.b and the Bases for SR 3.8.3.3. Regulatory Guide 1.137, Fuel Oil Systems for Standby Diesel Generators, also identifies that the water and sediment by centrifuge test provides an acceptable method for ensuring the initial and continuing quality of diesel fuel oil with respect to water and sediment content. Therefore, this alternate test provides adequate assurance, prior to storage tank addition, that the water and sediment content of the new dyed fuel oil will maintain diesel generator OPERABILITY. 3