April 6, 1994

Docket No. 50-293

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Mr. E. Thomas Boulette, Ph.D
Senior Vice President - Nuclear
Boston Edison Company
Pilgrim Nuclear Power Station
RFD #1 Rocky Hill Road
Plymouth, Massachusetts 02360

Dear Mr. Boulette:

SUBJECT: ISSUANCE OF AMENDMENT NO. 151 TO FACILITY OPERATING LICENSE NO. DPR-35, PILGRIM NUCLEAR POWER STATION (TAC NOS. M83787, M87191, M88390)

The Commission has issued the enclosed Amendment No. 151 to Facility Operating License No. DPR-35 for the Pilgrim Nuclear Power Station. This amendment is in response to your applications dated June 7, 1993, August 9, 1993, and December 10, 1993.

This amendment revises the Technical Specification (TS) to support a 24-month fuel cycle. The TS changes include extending surveillance intervals and adjusting setpoints as justified in the Safety Evaluation.

A copy of the related Safety Evaluation is also enclosed. Notice of Issuance will be included in the Commission's biweekly Federal Register Notice.

Sincerely,

Original signed by
Ronald B. Eaton, Senior Project Manager
Project Directorate I-3
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Enclosures:
1. Amendment No. 151 to License No. DPR-35
2. Safety Evaluation

cc w/enclosures:
See next page

*See previous concurrence

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

April 6, 1994

Docket No. 50-293

Mr. E. Thomas Boulette, Ph.D
Senior Vice President - Nuclear
Boston Edison Company
Pilgrim Nuclear Power Station
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Plymouth, Massachusetts 02360

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Ronald B. Eaton, Senior Project Manager
Project Directorate I-3
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

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1. Amendment No. 151 to
   License No. DPR-35
2. Safety Evaluation

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See next page

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

BOSTON EDISON COMPANY

DOCKET NO. 50-293

PILGRIM NUCLEAR POWER STATION

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No.151
License No. DPR-35

1. The Nuclear Regulatory Commission (the Commission or the NRC) has found that:

   A. The applications for amendment filed by the Boston Edison Company (the licensee) dated June 7, 1993, August 9, 1993, and December 10, 1993, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance: (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 3.B of Facility Operating License No. DPR-35 is hereby amended to read as follows:

Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 151, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This amendment is effective as of the date of issuance. Implementation of the extended surveillance intervals will in some cases be put into effect within 90 days. For instrumentation requiring setpoint changes, implementation of the extended surveillance intervals will not be put into effect until the changes are made.

FOR THE NUCLEAR REGULATORY COMMISSION

Walter R. Butler

Walter R. Butler, Director
Project Directorate I-3
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Technical
Specifications

Date of Issuance: April 6, 1994

ATTACHMENT TO LICENSE AMENDMENT NO. 151

FACILITY OPERATING LICENSE NO. DPR-35

DOCKET NO. 50-293

Replace the following pages of the Appendix A Technical Specifications with the attached pages. The revised pages are identified by Amendment number and contain vertical lines indicating the area of change.

Remove	Insert
4	4
5a	5a
27	27
29	29
32	32
40	40
45	45
46a	46a
47	47
48	48
49	49
50	50
50a	50a
53	53
53a	53a
55a	55a
59a	59a
60	60
61	61
62	62
63	63
64	64
68	68
69	69
77	77
125b	125b
137a	137a
137b	137b
137c	137c
158	158
158B	158B
158C	158C
169	169
172	172
173	173
190	190
193	193
193a	193a
194a	194a
196	196
197	197
201	201

1. At least one door in each access opening is closed.

2. The standby gas treatment system is operable.

3. All automatic ventilation system isolation valves are operable or secured in the isolated position.

O. Operating Cycle - Interval between the end of one refueling outage and the end of the next subsequent refueling outage.

P. Refueling Frequencies

1. Refueling Outage - Refueling outage is the period of time between the shutdown of the unit prior to a refueling and the startup of the plant after that refueling. For the purpose of designating frequency of testing and surveillance, a refueling outage shall mean a regularly scheduled outage; however, where such outages occur within 11 months of completion of the previous refueling outage, the required surveillance testing need not be performed until the next regularly scheduled outage (Definitions U and V apply).

2. Refueling Interval - Refueling interval applies only to ASME Code, Section XI IWP and IWV surveillance tests. For the purpose of designating frequency of these code tests, a refueling interval shall mean at least once every 24 months.

Q. Alteration of the Reactor Core - The act of moving any component in the region above the core support plate, below the upper grid and within the shroud. Normal control rod movement with the control rod drive hydraulic system is not defined as a core alteration. Normal movement of in-core instrumentation is not defined as a core alteration.

R. Reactor Vessel Pressure - Unless otherwise indicated, reactor vessel pressures listed in the Technical Specifications are those measured by the reactor vessel steam space detectors.

S. Thermal Parameters

1. Minimum Critical Power Ratio (MCPR) - the value of critical power ratio associated with the most limiting assembly in the reactor core. Critical Power Ratio (CPR) is the ratio of that power in a fuel assembly, which is calculated to cause some point in the assembly to experience boiling transition, to the actual assembly operating power.

2. Transition Boiling - Transition boiling means the boiling regime between nucleate and film boiling. Transition boiling is the regime in which both nucleate and film boiling occur intermittently with neither type being completely stable.

3. Total Peaking Factor - The ratio of the fuel rod surface heat flux to the heat flux of an average rod in an identical geometry fuel assembly operating at the core average bundle power.

1.0 DEFINITIONS (Continued)

U. Surveillance Frequency - Each Surveillance Requirement shall be performed within the specified surveillance interval with a maximum allowable extension not to exceed 25 percent of the specified surveillance interval.

The Surveillance Frequency establishes the limit for which the specified time interval for Surveillance Requirements may be extended. It permits an allowable extension of the normal surveillance interval to facilitate surveillance schedule and consideration of plant operating conditions that may not be suitable for conducting the surveillance; e.g., transient conditions or other ongoing surveillance or maintenance activities. It is not intended that this provision be used repeatedly as a convenience to extend surveillance intervals beyond that specified for surveillances that are not performed during refueling outages. The limitation of Definition "U" is based on engineering judgment and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the Surveillance Requirements. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval.

V. Surveillance Interval - The surveillance interval is the calendar time between surveillance tests, checks, calibrations, and examinations to be performed upon an instrument or component when it is required to be operable. These tests may be waived when the instrument, component, or system is not required to be operable, but the instrument, component, or system shall be tested prior to being declared operable. The operating cycle interval is 24 months and the 25% tolerance given in Definition "U" is applicable. The refueling interval is 24 months and the 25% tolerance specified in definition "U" is applicable.

W. Fire Suppression Water System - A fire suppression water system shall consist of: a water source(s); gravity tank(s) or pump(s); and distribution piping with associated sectionalizing control or isolation valves. Such valves shall include hydrant post indicator valves and the first valve ahead of the water flow alarm device on each sprinkler, hose standpipe or spray system riser.

X. Staggered Test Basis - A staggered test basis shall consist of: (a) a test schedule for n systems, subsystems, trains, or other designated components obtained by dividing the specified test interval into n equal subintervals; (b) the testing of one system, subsystem, train or other designated components at the beginning of each subinterval.

Y. Source Check - A source check shall be the qualitative assessment of channel response when the channel sensor is exposed to a radioactive source.

PNPS Table 3.1.1 REACTOR PROTECTION SYSTEM (SCRAM) INSTRUMENTATION REQUIREMENT

Operable Inst. Channels per Trip System (1) Minimum	Operable Inst. Channels per Trip System (1) Avail.	Trip Function	Trip Level Setting	Modes in Which Function Must Be Operable: Refuel (7)	Modes in Which Function Must Be Operable: Startup/Hot Standby	Modes in Which Function Must Be Operable: Run	Action (1)
1	1	Mode Switch in Shutdown		X	X	X	A
1	1	Manual Scram		X	X	X	A
		IRM					
3	4	High Flux	≤120/125 of full scale	X	X	(5)	A
3	4	Inoperative		X	X	(5)	A
		APRM					
2	3	High Flux	(15)	(17)	(17)	X	A or B
2	3	Inoperative	(13)	X	X(9)	X	A or B
2	3	High Flux (15%)	≤15% of Design Power	X	X	(16)	A or B
2	2	High Reactor Pressure	≤1063.5 psig	X(10)	X	X	A
2	2	High Drywell Pressure	≤2.22 psig	X(8)	X(8)	X	A
2	2	Reactor Low Water Level	≥11.7 In. Indicated Level	X	X	X	A
		SDIV High Water Level:	≤38 Gallons	X(2)	X	X	A
2	2	East					
2	2	West					
2	2	Main Condenser Low Vacuum	≥23 In. Hg Vacuum	X(3)	X(3)	X	A or C
2	2	Main Steam Line High Radiation	≤7x Normal Full Power Background (18)	X	X	X(18)	A or C
4	4	Main Steam Line Isolation Valve Closure	≤10% Valve Closure	X(3)(6)	X(3)(6)	X(6)	A or C
2	2	Turbine Control Valve Fast Closure	≥150 psig Control Oil Pressure at Acceleration Relay	X(4)	X(4)	X(4)	A or D
4	4	Turbine Stop Valve Closure	≤10% Valve Closure	X(4)	X(4)	X(4)	A or D

NOTES FOR TABLE 3.1.1 (Cont'd)

2. Permissible to bypass, with control rod block, for reactor protection system reset in refuel and shutdown positions of the reactor mode switch.
3. Permissible to bypass when reactor pressure is $\leq$576 psig.
4. Permissible to bypass when turbine first stage pressure is $\leq$112 psig.
5. IRM's are bypassed when APRM's are onscale and the reactor mode switch is in the run position.
6. The design permits closure of any two lines without a scram being initiated.
7. When the reactor is subcritical, fuel is in the reactor vessel and the reactor water temperature is less than 212°F, only the following trip functions need to be operable:

    A. Mode switch in shutdown
    B. Manual scram
    C. High flux IRM
    D. Scram discharge volume high level
    E. APRM (15%) high flux scram

8. Not required to be operable when primary containment integrity is not required.
9. Not required while performing low power physics tests at atmospheric pressure during or after refueling at power levels not to exceed 5 MW(t).
10. Not required to be operable when the reactor pressure vessel head is not bolted to the vessel.
11. Deleted
12. Deleted
13. An APRM will be considered inoperable if there are less than 2 LPRM inputs per level or there is less than 50% of the normal complement of LPRM's to an APRM.
14. Deleted
15. The APRM high flux trip level setting shall be as specified in the CORE OPERATING LIMITS REPORT, but shall in no case exceed 120% of rated thermal power.
16. The APRM (15%) high flux scram is bypassed when in the run mode.
17. The APRM flow biased high flux scram is bypassed when in the refuel or startup/hot standby modes.
18. Within 24 hours prior to the planned start of hydrogen injection with the reactor power at greater than 20% rated power, the normal full power radiation background level and associated trip setpoints may be changed based on a calculated value of the radiation level expected during the injection of hydrogen. The background radiation level and associated trip setpoints may be adjusted based on either calculations or measurements of actual radiation levels resulting from hydrogen injection. The background radiation level shall be determined and associated trip setpoints shall be set within 24 hours of re-establishing normal radiation levels after completion of hydrogen injection and prior to withdrawing control rods at reactor power levels below 20% rated power.

TABLE 4.1.2
REACTOR PROTECTION SYSTEM (SCRAM) INSTRUMENT CALIBRATION
MINIMUM CALIBRATION FREQUENCIES FOR REACTOR PROTECTION INSTRUMENT CHANNELS

Instrument Channel	Calibration Test (5)	Minimum Frequency (2)
IRM High Flux	Comparison to APRM on Controlled Shutdowns	Note (4)
	Full Calibration	Once per Operating Cycle
APRM High Flux		
Output Signal	Heat Balance	Once every 3 Days
Flow Bias Signal	Calibrate Flow Comparator and Flow Bias Network	At Least Once Every 18 Months
	Calibrate Flow Bias Signal (1)	Every 3 Months
LPRM Signal	TIP System Traverse	Every 1000 Effective Full Power Hours
High Reactor Pressure	Note (7)	Note (7)
High Drywell Pressure	Note (7)	Note (7)
Reactor Low Water Level	Note (7)	Note (7)
High Water Level in Scram Discharge Tanks	Note (7)	Note (7)
Turbine Condenser Low Vacuum	Note (7)	Note (7)
Main Steam Line Isolation Valve Closure	Note (6)	Note (6)
Main Steam Line High Radiation	Standard Current Source (3)	Every 3 Months
Turbine First Stage Pressure Permissive	Note (7)	Note (7)
Turbine Control Valve Fast Closure	Standard Pressure Source	Every 3 Months
Turbine Stop Valve Closure	Note (6)	Note (6)
Reactor Pressure Permissive	Note (7)	Note (7)

3.1 BASES (Cont'd)

Scram Discharge Instrument Volume

The control rod drive scram system is designed so that all of the water that is discharged from the reactor by a scram can be accommodated in the discharge piping. The two scram discharge volumes have a capacity of 48 gallons of water each and are at the low points of the scram discharge piping.

During normal operation the scram discharge volume system is empty; however, should it fill with water, the water discharged to the piping could not be accommodated which would result in slow scram times or partial control rod insertion. To preclude this occurrence, redundant and diverse level detection devices in the scram discharge instrument volumes have been provided. The instruments are set to alarm, initiate a control rod block, and scram the reactor at three different progressively increasing water levels in the volume. As indicated above, there is sufficient volume in the piping to accommodate the scram without impairment of the scram times or amount of insertion of the control rods. This function shuts the reactor down while sufficient volume remains to accommodate the discharged water and precludes the situation in which a scram would be required but not be able to perform its function properly.

4.1 BASES

The reactor protection system is made up of two independent trip systems. There are usually four channels to monitor each parameter with two channels in each trip system. The outputs of the channels in a trip system are combined in a logic so that either channel will trip that trip system. The tripping of both trip systems will produce a reactor scram. The system meets the intent of IEEE-279 for nuclear power plant protection systems. Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with General Electric Company Topical Report NEDC-30851P-A, "Technical Specification Improvement Analysis for BWR Reactor Protection System," as approved by the NRC and documented in the safety evaluation report (NRC letter to T. A. Pickens from A. Thadani dated July 15, 1987).

A comparison of Tables 4.1.1 and 4.1.2 indicates that two instrument channels have not been included in the latter table. These are: mode switch in shutdown and manual scram. All of the devices or sensors associated with these scram functions are simple on-off switches and, hence, calibration during operation is not applicable (i.e., the switch is either on or off).

The sensitivity of LPRM detectors decreases with exposure to neutron flux at a slow and approximately constant rate. This is compensated for in the APRM system by calibrating every three days using heat balance data and by calibrating individual LPRM's every 1000 effective full power hours using TIP traverse data.

PNPS TABLE 3.2.A
INSTRUMENTATION THAT INITIATES PRIMARY CONTAINMENT ISOLATION

Operable Instrument Channels Per Trip System (1) Minimum	Available	Instrument	Trip Level Setting	Action (2)
2(7)	2	Reactor Low Water Level	≥11.7" indicated level (3)	A and D
1	1	Reactor High Pressure	≤110 psig	D
2	2	Reactor Low-Low Water Level	at or above -46.3 in. indicated level (4)	A
2	2	Reactor High Water Level	≤45.3" indicated level (5)	B
2(7)	2	High Drywell Pressure	≤2.22 psig	A
2	2	High Radiation Main Steam Line Tunnel (9)	≤7 times normal rated full power background	B
2	2	Low Pressure Main Steam Line	≥810 psig (8)	B
2(6)	2	High Flow Main Steam Line	≤136% of rated steam flow	B
2	2	Main Steam Line Tunnel Exhaust Duct High Temperature	≤170°F	B
2	2	Turbine Basement Exhaust Duct High Temperature	≤150°F	B
1	1	Reactor Cleanup System High Flow	≤300% of rated flow	C
2	2	Reactor Cleanup System High Temperature	≤150°F	C

3. Instrument set point corresponds to 137.96 inches above top of active fuel.

4. Instrument set point corresponds to 79.96 inches above top of active fuel.

5. Not required in Run Mode (bypassed by Mode Switch).

6. Two required for each steam line.

7. These signals also start SBGTS and initiate secondary containment isolation.

8. Only required in Run Mode (interlocked with Mode Switch).

9. Within 24 hours prior to the planned start of hydrogen injection with the reactor power at greater than 20% rated power, the normal full power radiation background level and associated trip setpoints may be changed based on a calculated value of the radiation level expected during the injection of hydrogen. The background radiation level and associated trip setpoints may be adjusted based on either calculations or measurements of actual radiation levels resulting from hydrogen injection. The background radiation level shall be determined and associated trip setpoints shall be set within 24 hours of re-establishing normal radiation levels after completion of hydrogen injection and prior to withdrawing control rods at reactor power levels below 20% rated power.

TABLE 3.2.B

INSTRUMENTATION THAT INITIATES OR CONTROLS THE CORE AND CONTAINMENT COOLING SYSTEMS

Minimum # of Operable Instrument Channels Per Trip System (1)	Trip Function	Trip Level Setting	Remarks
2	Reactor Low-Low Water Level	at or above -46.3 in. indicated level (4)	1. In conjunction with Low Reactor Pressure, initiates Core Spray and LPCI. 2. In conjunction with High Drywell Pressure, 94.4 - 115.6 second time delay and LPCI or Core Spray pump interlock initiates Auto Blowdown (ADS). 3. Initiates HPCI; RCIC. 4. Initiates starting of Diesel Generators.
2	Reactor High Water Level	≤ +45.3" indicated level	Trips HPCI and RCIC turbines.
1	Reactor Low Level (inside shroud)	>-151" indicated level	Prevents inadvertent operation of containment spray during accident condition. (Indicative of 2/3 core coverage)
2	Containment High Pressure	$1.55 \le p \le 1.82$ psig	Prevents inadvertent operation of containment spray during accident condition. Instrument is set to trip at or before 1.82 increasing and reset at or before 1.55 decreasing.

TABLE 3.2.B (Cont'd)

INSTRUMENTATION THAT INITIATES OR CONTROLS THE CORE AND CONTAINMENT COOLING SYSTEMS

Minimum # of Operable Instrument Channels Per Trip System (1)	Trip Function	Trip Level Setting	Remarks
2	High Drywell Pressure	≤2.22 psig	1. Initiates Core Spray; LPCI; HPCI. 2. In conjunction with Low-Low Reactor Water Level, 94.4 - 115.6 second time delay and LPCI or Core Spray pump running, initiates Auto Blowdown (ADS) 3. Initiates starting of Diesel Generators 4. In conjunction with Reactor Low Pressure initiates closure of HPCI vacuum breaker containment isolation valves.
1	Reactor Low Pressure	400 psig ± 5	Permissive for Opening Core Spray and LPCI Admission valves.
1	Reactor Low Pressure	≤110 psig	In conjunction with PCIS signal permits closure of RHR (LPCI) injection valves.
1	Reactor Low Pressure	400 psig ± 5	In conjunction with Low-Low Reactor Water Level initiates Core Spray and LPCI.
2	Reactor Low Pressure	900 psig ± 5	Prevents actuation of LPCI break detection circuit.
2	Reactor Low Pressure	80 psig ± 5	Isolates HPCI and in conjunction with High Drywell Pressure initiates closure of HPCI vacuum breaker containment isolation valves.

PNPS TABLE 3.2.B (Cont'd)
INSTRUMENTATION THAT INITIATES OR CONTROLS THE CORE AND CONTAINMENT COOLING SYSTEMS

Minimum # of Operable Instrument Channels Per Trip System (1)	Trip Function	Trip Level Setting	Remarks
1	Core Spray Pump Start Timer	0.21 < t < 1 sec.	Initiates sequential starting of CSCS pumps on any auto start.
1	LPCI Pump Start Timer	4.16 < t < 5.84 sec.	
1	LPCI Pump Start Timer	9.5 < t < 11.5 sec.	
1	Auto Blowdown Timer	≥ 94.4, ≤115.6 sec.	In conjunction with Low Low Reactor Water Level, High Drywell Pressure and LPCI or Core Spray Pump running interlock, initiates Auto Blowdown.
2	ADS Drywell Pressure Bypass Timer	9 ≤ t ≤ 15.4 min.	Permits starting CS and LPCI pumps and actuating ADS SRV's if RPV water level is low and drywell pressure is not high.
2	RHR (LPCI) Pump Discharge Pressure interlock	150 ± 10 psig	Defers ADS actuation pending confimation of Low Pressure core cooling system operation. (LPCI or Core Spray Pump running interlock.)
2	Core Spray Pump Discharge Pressure Interlock	150 ± 10 psig	
2	Emergency Bus Voltage Relay	20-25% of rated voltage resets at less than or equal to 50%	1. Permits closure of the Diesel Generator to an unloaded emergency bus. 2. Permits starting of CSCS 4 kV motors.

TABLE 3.2.B (Cont'd)

INSTRUMENTATION THAT INITIATES OR CONTROLS THE CORE AND CONTAINMENT COOLING SYSTEMS

Minimum # of Operable Instrument Channels Per Trip System (1)	Trip Function	Trip Level Setting	Remarks
2	Startup Transformer Loss of Voltage	At 0 Volts between $0.96 \leq t \leq 1.34$ seconds Time Delay.	1. Trips Startup Transformer to Emergency Bus Breaker. 2. Locks out automatic closure of Startup Transformer to Emergency Bus. 3. Initiates starting of Diesel Generators in conjunction with loss of auxiliary transformer. 4. Prevents simultaneous starting of CSCS components. 5. Starts load shedding logic for Diesel Operation in conjunction with (a) Low Low Reactor Water Level and Low Reactor Pressure or (b) High drywell pressure or (c) Core Standby Cooling System components in service in conjunction with Auxiliary Transformer breaker open.

TABLE 3.2.B (Cont'd)
INSTRUMENTATION THAT INITIATES OR CONTROLS THE CORE AND CONTAINMENT COOLING SYSTEMS

Minimum # of Operable Instrument Channels Per Trip System (1)	Trip Function	Trip Level Setting	Remarks
2	Startup Transformer Degraded Voltage	3878.7V ± .51% with 10.24 ± 0.36 seconds time delay.	1. Trips Startup Transformer to Emergency Bus Breaker. 2. Locks out automatic closure of Startup Transformer to Emergency Bus. 3. Initiates starting of Diesel Generators in conjunction with loss of auxiliary transformer. 4. Prevents simultaneous starting of CSCS components. 5. Starts load shedding logic for Diesel Operation in conjunction with a) Low Low Reactor Water Level and Low Reactor Pressure or b) High drywell pressure or c) Core Standby Cooling System components in service in conjunction with Auxiliary Transformer breaker open.

NOTES FOR TABLE 3.2.B

1. Whenever any CSCS subsystem is required by Section 3.5 to be operable, there shall be two (Note 5) operable trip systems. If the first column cannot be met for one of the trip systems, that system shall be repaired or the reactor shall be placed in the Cold Shutdown Condition within 24 hours after this trip system is made or found to be inoperable.

2. Close isolation valves in RCIC subsystem.

3. Close isolation valves in HPCI subsystem.

4. Instrument set point corresponds to 79.96 inches above top of active fuel.

5. RCIC has only one trip system for these sensors.

TABLE 3.2.B.1

INSTRUMENTATION THAT MONITORS EMERGENCY BUS VOLTAGE

Minimum # of Operable Instrument Channels Per Trip system	Function	Setting	Remarks
1	Emergency 4160V Buses A5 & A6 Degraded Voltage Annunciation (1)	3958.5V + 0.5%, -0.24% with 10.24 ± 0.36 seconds seconds time delay	Alerts Operator to possible degraded voltage conditions. Provides permissive to initiate load shedding in conjunction with LOCA signal.

(1) In the event that the alarm system is determined inoperable, commence logging safety related bus voltage every ½ hour until such time as the alarm is restored to operable status.

TABLE 3.2.C-2

CONTROL ROD BLOCK INSTRUMENTATION SETPOINTS

Trip Function	Trip Setpoint
APRM Upscale	(1) (2)
APRM Inoperative	Not Applicable
APRM Downscale	$\geq$ 2.5 Indicated on Scale
Rod Block Monitor (Power Dependent)	(1) (3)
Rod Block Monitor Inoperative	Not Applicable
Rod Block Monitor Downscale	(1) (3)
IRM Downscale	$\geq$ 5/125 of Full Scale
IRM Detector not in Startup Position	Not Applicable
IRM Upscale	$\leq$ 108/125 of Full Scale
IRM Inoperative	Not Applicable
SRM Detector not in Startup Position	Not Applicable
SRM Downscale	$\geq$ 3 counts/second
SRM Upscale	$\leq 10^5$ counts/second
SRM Inoperative	Not Applicable
Scram Discharge Instrument Volume Water Level - High	$\leq$ 17 gallons
Scram Discharge Instrument Volume - Scram Trip Bypassed	Not Applicable
Recirculation Flow Converter - Upscale	$\leq$ 120/125 of Full Scale
Recirculation Flow Converter - Inoperative	Not Applicable
Recirculation Flow Converter - Comparator Mismatch	$\leq$ 8% Flow Deviation

(1) The trip level setting shall be as specified in the CORE OPERATING LIMITS REPORT.

(2) When the reactor mode switch is in the refuel or startup positions, the APRM rod block trip setpoint shall be less than or equal to 13% of rated thermal power, but always less than the APRM flux scram trip setting.

(3) The RBM bypass time delay (t_{d2}) shall be < 2.0 seconds.

TABLE 3.2-G

INSTRUMENTATION THAT INITIATES RECIRCULATION PUMP TRIP
AND
ALTERNATE ROD INSERTION

Minimum Number of Operable or Tripped Instrument Channels Per Trip System (1)	Trip Function	Trip Level Setting
2	High Reactor Dome Pressure	1175 ± 5 PSIG
2	Low-Low Reactor Water Level	≥-46.3" indicated level

Actions (1) There shall be two (2) operable trip systems for each function.

(a) If the minimum number of operable or tripped instrument channels for one (1) trip system cannot be met, restore the trip system to operable status within 14 days or be in at least hot shutdown within 24 hours.

(b) If the minimum operability conditions (1.a) cannot be met for both (2) trip systems, be in at least hot shutdown within 24 hours.

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TABLE 4.2.A

MINIMUM TEST AND CALIBRATION FREQUENCY FOR PCIS

	Instrument Channel (5)	Instrument Functional Test	Calibration Frequency	Instrument Check
1)	Reactor High Pressure	(1)	Once/3 months	None
2)	Reactor Low-Low Water Level	Once/3 Months (7)	(7)	Once/day
3)	Reactor High Water Level	Once/3 Months (7)	(7)	Once/day
4)	Main Steam High Temp.	(1)	Once/3 months	None
5)	Main Steam High Flow	Once/3 Months (7)	(7)	Once/day
6)	Main Steam Low Pressure	Once/3 Months (7)	(7)	Once/day
7)	Reactor Water Cleanup High Flow	(1)	Once/3 months	Once/day
8)	Reactor Water Cleanup High Temp.	(1)	Once/3 months	None

	Logic System Functional Test (4) (6)	Frequency
1)	Main Steam Line Isolation Vvs. Main Steam Line Drain Vvs. Reactor Water Sample Vvs.	Once/operating cycle
2)	RHR - Isolation Vv. Control Shutdown Cooling Vvs. Head Spray Discharge to Radwaste	Once/operating cycle
3)	Reactor Water Cleanup Isolation	Once/operating cycle
4)	Drywell Isolation Vvs. TIP Withdrawal Atmospheric Control Vvs. Sump Drain Valves	Once/operating cycle
5)	Standby Gas Treatment System Reactor Building Isolation	Once/operating cycle

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TABLE 4.2.B
MINIMUM TEST AND CALIBRATION FREQUENCY FOR CSCS

	Instrument Channel	Instrument Functional Test	Calibration Frequency	Instrument Check
1)	Reactor Water Level	(1) (7)	(7)	Once/day
2)	Drywell Pressure	(1) (7)	(7)	Once/day
3)	Reactor Pressure	(1) (7)	(7)	Once/day
4)	Auto Sequencing Timers	NA	Once/operating cycle	None
5)	ADS - LPCI or CS Pump Disch. Pressure Interlock	(1)	Once/3 months	None
6)	Start-up Transf. (4160V)			
	a. Loss of Voltage Relays	Monthly	Once/operating cycle	None
	b. Degraded Voltage Relays	Monthly	Once/operating cycle	None
7)	Trip System Bus Power Monitors	Once/operating cycle	NA	Once/day
8)	Recirculation System d/p	(1)	Once/3 months	Once/day
9)	Core Spray Sparger d/p	NA	Once/18 months	Once/day
10)	Steam Line High Flow (HPCI & RCIC)	(1)	Once/3 months	None
11)	Steam Line High Temp. (HPCI & RCIC)	(1)	Once/3 months	None
12)	Safeguards Area High Temp.	(1)	Once/3 months	None
13)	RCIC Steam Line Low Pressure	(1)	Once/3 months	None
14)	HPCI Suction Tank Levels	(1)	Once/3 months	None
15)	Emergency 4160V Buses A5 & A6 Loss of Voltage Relays	Monthly	Once/operating Cycle	None

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TABLE 4.2.B

MINIMUM TEST AND CALIBRATION FREQUENCY FOR CSCS

Logical System Functional Test (4) (6)	Frequency	Remarks
1) Core Spray Subsystem	Once/operating cycle	
2) Low Press. Coolant Injection Subsystem	Once/operating cycle	
3) Containment Spray Subsystem	Once/operating cycle	
4) HPCI Subsystem	Once/operating cycle	
5) HPCI Subsystem Auto Isolation	Once/operating cycle	
6) ADS Subsystem	Once/operating cycle	
7) RCIC Subsystem Auto Isolation	Once/operating cycle	
8) Diesel Generator Initiation	Once/operating cycle	
9) Area Cooling for Safeguard System	Once/operating cycle	

PNPS TABLE 4.2.C
MINIMUM TEST AND CALIBRATION FREQUENCY FOR CONTROL ROD BLOCKS ACTUATION

Instrument Channel	Instrument Functional Test	Calibration	Instrument Check
APRM - Downscale	Once/3 Months	Once/3 Months	Once/Day
APRM - Upscale	Once/3 Months	Once/3 Months	Once/Day
APRM - Inoperative	Once/3 Months	Not Applicable	Once/Day
IRM - Upscale	(2) (3)	Startup or Control Shutdown	(2)
IRM - Downscale	(2) (3)	Startup or Control Shutdown	(2)
IRM - Inoperative	(2) (3)	Not Applicable	(2)
RBM - Upscale	Once/3 Months	Once/6 Months	Once/Day
RBM - Downscale	Once/3 Months	Once/6 Months	Once/Day
RBM - Inoperative	Once/3 Months	Not Applicable	Once/Day
SRM - Upscale	(2) (3)	Startup or Control Shutdown	(2)
SRM - Inoperative	(2) (3)	Not Applicable	(2)
SRM - Detector Not in Startup Position	(2) (3)	Not Applicable	(2)
SRM - Downscale	(2) (3)	Startup or Control Shutdown	(2)
IRM - Detector Not in Startup Position	(2) (3)	Not Applicable	(2)
Scram Discharge Instrument Volume Water Level-High	Once/3 Months	Refuel	Not Applicable
Scram Discharge Instrument Volume-Scram Trip Bypassed	Once/3 Months	Not Applicable	Not Applicable
Recirculation Flow Converter	Not Applicable	Once/Operating Cycle	Once/Day
Recirculation Flow Converter-Upscale	Once/3 Months	Once/3 Months	Once/Day
Recirculation Flow Converter-Inoperative	Once/3 Months	Not Applicable	Once/Day
Recirculation Flow Converter-Comparator Off Limits	Once/3 Months	Once/3 Months	Once/Day
Recirculation Flow Process Instruments	Not Applicable	Once/Operating Cycle	Once/Day

Logic System Functional Test (4) (6)

System Logic Check	Once/Operating cycle

PNPS

TABLE 4.2.D

MINIMUM TEST AND CALIBRATION FREQUENCY FOR RADIATION MONITORING SYSTEMS

	Instrument Channels	Instrument Functional Test	Calibration	Instrument Check (2)
1)	Refuel Area Exhaust Monitors - Upscale	(1)	Once/3 months	Once/day
2)	Refuel Area Exhaust Monitors - Downscale	(1)	Once/3 months	Once/day

	Logic System Functional Test (4) (6)	Frequency
1)	Reactor Building Isolation	Once/operating cycle
2)	Standby Gas Treatment System Actuation	Once/operating cycle

3.2 In addition to reactor protection instrumentation which initiates a reactor scram, protective instrumentation has been provided which initiates action to mitigate the consequences of accidents which are beyond the operator's ability to control, or terminates operator errors before they result in serious consequences. This set of specifications provides the limiting conditions of operation for the primary system isolation function, initiation of the core cooling systems, control rod block, and standby gas treatment systems. The objectives of the Specifications are, (i) to assure the effectiveness of the protective instrumentation when required by preserving its capability to tolerate a single failure of any component of such systems even during periods when portions of such systems are out of service for maintenance, and (ii) to prescribe the trip settings required to assure adequate performance. When necessary, one channel may be made inoperable for brief intervals to conduct required functional tests and calibrations.

Some of the settings on the instrumentation that initiate or control core and containment cooling have tolerances explicitly stated where the high and low values are both critical and may have a substantial effect on safety. The set points of other instrumentation, where only the high or low end of the setting has a direct bearing on safety, are chosen at a level away from the normal operating range to prevent inadvertent actuation of the safety system involved and exposure to abnormal situations.

Actuation of primary containment valves is initiated by protective instrumentation shown in Table 3.2.A which senses the conditions for which isolation is required. Such instrumentation must be available whenever primary containment integrity is required.

The instrumentation which initiates primary system isolation is connected in a dual bus arrangement.

The low water level instrumentation closes all isolation valves except those in Groups 1, 4 and 5. This trip setting is adequate to prevent core uncovery in the case of a break in the largest line assuming a 60 second valve closing time. Required closing times are less than this.

The low low reactor water level instrumentation closes the Main Steam Line Isolation Valves, Main Steam Drain Valves, Recirc Sample Valves (Group 1) activates the CSCS subsystems, starts the emergency diesel generators and trips the recirculation pumps. This trip setting level was chosen to be high enough to prevent spurious actuation but low enough to initiate CSCS operation and primary system isolation so that no fuel damage will occur and so that post accident cooling can be accomplished and the guidelines of 10 CFR 100 will not be violated. For large breaks up to the complete circumferential break of a 28-inch recirculation line and with the trip setting given above, CSCS initiation and primary system isolation are initiated in time to meet the above criteria.

3.2 BASES (Cont'd)

The high drywell pressure instrumentation is a diverse signal to the water level instrumentation and in addition to initiating CSCS, it causes isolation of Group 2 isolation valves. For the breaks discussed above, this instrumentation will initiate CSCS operation at about the same time as the low low water level instrumentation; thus the results given above are applicable here also. The low low water level instrumentation initiates protection for the full spectrum of loss-of-coolant accidents and causes isolation of Group 1 isolation valves.

Venturis are provided in the main steam lines as a means of measuring steam flow and also limiting the loss of mass inventory from the vessel during a steam line break accident. The primary function of the instrumentation is to detect a break in the main steam line. For the worst case accident, main steam line break outside the drywell, the steam flow trip setting in conjunction with the flow limiters and main steam line valve closure, limits the mass inventory loss such that fuel is not uncovered, fuel temperatures remain approximately 1000°F and release of radioactivity to the environs is well below 10 CFR 100 guidelines.

Temperature monitoring instrumentation is provided in the main steam line tunnel and the turbine basement to detect leaks in these areas. Trips are provided on this instrumentation and when exceeded, cause closure of isolation valves. The setting of 170°F for the main steam line tunnel detector is low enough to detect leaks of the order of 5 to 10 gpm; thus, it is capable of covering the entire spectrum of breaks. For large breaks, the high steam flow instrumentation is a backup to the temperature instrumentation.

High radiation monitors in the main steam line tunnel have been provided to detect gross fuel failure as in the control rod drop acci-

4.2 BASES (Cont'd)

The automatic pressure relief instrumentation can be considered to be a 1 out of 2 logic system and the discussion above applies also.

The instrumentation which is required for the recirculation pump trip and alternate rod insertion systems incorporate analog transmitters. The transmitter calibration frequency is once per refueling outage, which is consistent with both the equipment capabilities and the requirements for similar equipment used at Pilgrim. The Trip Unit Calibration and Instrument Functional Test is specified at monthly, which is the same frequency specified for other similar protective devices. An instrument check is specified at once per day; this is considered to be an appropriate frequency, commensurate with the design applications and the fact that the recirculation pump trip and alternate rod insertion systems are backups to existing protective instrumentation.

Control Rod Block and PCIS instrumentation common to RPS instrumentation have surveillance intervals and maintenance outage times selected in accordance with NEDC-30851P-A, Supplements 1 and 2 as approved by the NRC and documented in SERs (letters to D. N. Grace from C. E. Rossi dated September 22, 1988 and January 6, 1989).

A logic system functional test interval of 24 months was selected to minimize the frequency of safety system inoperability due to testing and to minimize the potential for inadvertent safety system trips and their attendant transients.

LIMITING CONDITIONS FOR OPERATION

3.6.C.2 Leakage Detection Systems (Cont'd)

2. One channel of a drywell atmospheric particulate radioactivity monitoring system, or

3. One channel of a drywell atmospheric gaseous radioactivity monitoring system.

b. 1. At least one drywell sump monitoring system shall be Operable; otherwise, be in Hot Shutdown within the next 12 hours and in Cold Shutdown within the following 24 hours.

2. At least one gaseous or particulate radioactivity monitoring channel must be Operable; otherwise, reactor operation may continue for up to 31 days provided grab samples are obtained and analyzed every 24 hours, or be in Hot Shutdown within the next 12 hours and in Cold Shutdown within the following 24 hours.

c. With no required leakage detection systems Operable, be in Cold Shutdown within 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.C.2 Leakage Detection Systems (Cont'd)

2. An instrument channel calibration at least once per operating cycle.

b. For each required drywell atmospheric radioactivity monitoring system perform:

1. An instrument check at least once per day,

2. An instrument functional test at least once per 31 days, and

3. An instrument channel calibration at least once per operating cycle.

LIMITING CONDITIONS FOR OPERATION

3.6.I Shock Suppressors (Snubbers)

1. During all modes of operation except Cold Shutdown and Refuel, all safety-related snubbers listed in PNPS Procedures shall be operable except as noted in 3.6.I.2 through 3.6.I.3 below.

   An Inoperable Snubber is a properly fabricated, installed and sized snubber which cannot pass its functional test.

   Upon determination that a snubber is either improperly fabricated, installed or sized, the corrective action will be as specified for an inoperable snubber in Section 3.6.I.2.

2. From and after the time that a snubber is determined to be inoperable, replace or repair the snubber during the next 72 hours, and initiate an engineering evaluation to determine if the components supported by the snubber(s) were adversely affected by the inoperability of the snubbers and to ensure that the supported component remains capable of meeting its intended function in the specific safety system involved.

   Further corrective action for this snubber, and all generically susceptible snubbers, shall be determined by an engineering evaluation.

3. From and after the time a snubber is determined to be inoperable, improperly fabricated, improperly installed or improperly sized, if the requirements of Section(s) 3.6.I.1 and 3.6.I.2 cannot be met, then the affected safety system, or affected portions of that system, shall be declared inoperable, and the limiting condition for that system entered, as appropriate.

SURVEILLANCE REQUIREMENTS

4.6.I Shock Suppressors (Snubbers)

The following surveillance requirements apply to all safety related hydraulic and mechanical snubbers listed in PNPS Procedures.

The required visual inspection interval varies inversely with the observed cumulative number of inoperable snubbers found during an inspection. Inspections performed before that interval has elapsed may be used as a new reference point to determine the next inspection. However, the results of such early inspections performed before the original time interval has elapsed may not be used to lengthen the required interval.

Number of snubbers found inoperable during inspection or during inspection interval:

Inoperable Snubbers	Subsequent Visual Inspection Interval
0	24 Months ± 25%
1	18 Months ± 25%
2	12 Months ± 25%
3,4	6 Months ± 25%
5,6,7	124 Days ± 25%
8,9	62 Days ± 25%
10 or more	31 Days ± 25%

The required inspection interval shall not be lengthened more than one step at a time.

Snubbers may be categorized in two groups, "accessible" or "inaccessible" based on their accessibility for inspection during reactor operation. These two groups may be inspected independently according to the above schedule.

1. Visual Inspection Acceptance Criteria

A. Visual inspections shall verify:

3.6.I Shock Suppressors (Snubbers)

4. Snubbers may be added to, or removed from, per 10 CFR 50.59, safety related systems without prior NRC approval. The addition or deletion of snubbers shall be reported to the NRC in accordance with 10 CFR 50.59.

4.6.I Shock Suppressors (Snubbers)

1. That there are no visible indications of damage or impaired operability.

2. Attachments to the foundation or support structure are such that the functional capability of the snubber is not suspect.

B. Snubbers which appear INOPERABLE as a result of visual inspections may be determined OPERABLE for the purpose of establishing the next visual inspection interval provided that:

1. The cause of the rejection is clearly established and remedied for that particular snubber, and

2. The affected snubber is functionally tested, when necessary, in the as found condition and determined OPERABLE per specifications 4.6.I.2.B., 4.6.I.2.C., as applicable.

C. For any snubber determined inoperable per specification 4.6.I.2, clearly establish the cause of rejection and remedy the problem for that snubber, and any generically susceptible snubber.

2. Functional Tests (Hydraulic and Mechanical Snubbers)

A. Schedule

At least once per operating cycle, a representative sample (12.5% of the total of each type: hydraulic, mechanical) of snubbers in use in the plant shall be functionally tested, either in place or in a bench test. For each snubber that does not meet the functional test acceptance criteria of

4.6.I Shock Suppressors (Snubbers)

Specification 4.6.I.2.B, or 4.6.I.2.C, as applicable, an additional 12.5% of that type of snubber shall be functionally tested.

B. General Snubber Functional Test Acceptance Criteria (Hydraulic and Mechanical)

The general snubber functional test shall verify that:

1. Activation (restraining action) is achieved within the specified range of velocity or acceleration in both tension and compression.

2. Snubber release, or bleedrate, as applicable, where required, is within the specified range in compression or tension. For snubbers specifically required not to displace under continuous load, the ability of the snubber to withstand load without displacement shall be verified.

C. Mechanical Snubbers Functional Test Acceptance Criteria

The mechanical snubber functional test shall verify that:

1. The force that initiates free movement of the snubber rod in either tension or compression is less than the specified maximum drag force. Drag force shall not have increased more than 50% since the last functional test.

3. Snubber Service Life Monitoring

A. A record of the service life

3.7.B Standby Gas Treatment System and Control Room High Efficiency Air Filtration System

1. Standby Gas Treatment System

a. Except as specified in 3.7.B.1.c below, both trains of the standby gas treatment system and the diesel generators required for operation of such trains shall be operable at all times when secondary containment integrity is required or the reactor shall be shutdown in 36 hours.

b. (1.) The results of the in-place cold DOP tests on HEPA filters shall show $\geq$99% DOP removal. The results of halogenated hydrocarbon tests on charcoal adsorber banks shall show $\geq$99% halogenated hydrocarbon removal.

(2.) The results of the laboratory carbon sample analysis shall show $\geq$95% methyl iodide removal at a velocity within 10% of system design, 0.5 to 1.5 mg/m^3 inlet methyl iodide concentration, $\geq$70% R.H. and $\geq$190°F. The analysis results are to be verified as acceptable within 31 days after sample removal, or declare that train inoperable and take the actions specified 3.7.B.1.c.

4.7.B Standby Gas Treatment System and Control Room High Efficiency Air Filtration System

1. Standby Gas Treatment System

a. (1.) At least once per operating cycle, it shall be demonstrated that pressure drop across the combined high efficiency filters and charcoal adsorber banks is less than 8 inches of water at 4000 cfm.

(2.) At least once per operating cycle, demonstrate that the inlet heaters on each train are operable and are capable of an output of at least 14 kW.

(3.) The tests and analysis of Specification 3.7.B.1.b. shall be performed at least once per operating cycle or following painting, fire or chemical release in any ventilation zone communicating with the system while the system is operating that could contaminate the HEPA filters or charcoal adsorbers.

(4.) At least once per operating cycle, automatic initiation of each branch of the standby gas treatment system shall be demonstrated, with Specification 3.7.B.1.d satisfied.

3.7.B (Continued)

2. Control Room High Efficiency Air Filtration System

* a. Except as specified in Specification 3.7.B.2.c below, both trains of the Control Room High Efficiency Air Filtration System used for the processing of inlet air to the control room under accident conditions and the diesel generator(s) required for operation of each train of the system shall be operable whenever secondary containment integrity is required and during fuel handling operations.

b. (1.) The results of the in-place cold DOP tests on HEPA filters shall show $\geq$99% DOP removal. The results of the halogenated hydrocarbon tests on charcoal adsorber banks shall show $\geq$99% halogenated hydrocarbon removal when test results are extrapolated to the initiation of the test.

(2.) The results of the laboratory carbon sample analysis shall show $\geq$95% methyl iodide removal at a velocity within 10% of system design, 0.05 to 0.15 mg/m^3 inlet methyl iodide concentration, $\geq$70% R.H., and $\geq$125°F. The analysis results are to be verified as acceptable within 31 days after sample removal, or declare that train inoperable and take the actions specified in 3.7.B.2.c.

4.7.B (Continued)

2. Control Room High Efficiency Air Filtration System

a. At least once per operating cycle the pressure drop across each combined filter train shall be demonstrated to be less than 6 inches of water at 1000 cfm or the calculated equivalent.

b. (1.) The tests and analysis of Specification 3.7.B.2.b shall be performed once per operating cycle or following painting, fire or chemical release in any ventilation zone communicating with the system while the system is operating.

(2.) In-place 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 which could affect the HEPA filter bank bypass leakage.

(3.) Halogenated hydrocarbon testing shall be performed after each complete or partial replacement of the charcoal adsorber bank or after any structural maintenance on the system housing which could affect the charcoal adsorber bank bypass leakage.

(4.) Each train shall be operated with the heaters in automatic for at least 15 minutes every month.

(5.) The test and analysis of Specification 3.7.B.2.b.(2) shall be performed after every 720 hours of system operation.

* During RFO #9, one train can be without its safety-related bus and/or its emergency diesel generator without entering the LCO action statement provided the conditions listed on page 158A are met.

3.7.B (Continued)

* c. From and after the date that one train of the Control Room High Efficiency Air Filtration System is made or found to be incapable of supplying filtered air to the control room for any reason, reactor operation or refueling operations are permissible only during the succeeding 7 days providing that within 2 hours all active components of the other CRHEAF train shall be demonstrated operable. If the system is not made fully operable within 7 days, reactor shutdown shall be initiated and the reactor shall be in cold shutdown within the next 36 hours and irradiated fuel handling operations shall be terminated within 2 hours. Fuel handling operations in progress may be completed.

d. Fans shall operate within ±10% of 1000 cfm.

4.7.B (Continued)

c. At least once per operating cycle demonstrate that the inlet heaters on each train are operable and capable of an output of at least 14 kw.

d. Perform an instrument functional test on the humidistats controlling the heaters once per operating cycle.

* During RFO #9, one train can be without its safety-related bus and/or its emergency diesel generator without entering the LCO action statement provided the conditions listed on page 158A are met.

3.7.A & 4.7.A Primary Containment

Group 6 - process lines are normally in use and it is therefore not desirable to cause spurious isolation due to high drywell pressure resulting from non-safety related causes. To protect the reactor from a possible pipe break in the system, isolation is provided by high temperature in the cleanup system area or high flow through the inlet to the cleanup system. Also, since the vessel could potentially be drained through the cleanup system, a low level isolation is provided.

Group 7 - The HPCI vacuum breaker line is designed to remain operable when the HPCI system is required. The signals which initiate isolation of the HPCI vacuum breaker line are indicative of a break inside containment and reactor pressure below that at which HPCI can operate.

The maximum closure time for the automatic isolation valves of the primary containment and reactor vessel isolation control system have been selected in consideration of the design intent to prevent core uncovering following pipe breaks outside the primary containment and the need to contain released fission products following pipe breaks inside the primary containment.

In satisfying this design intent an additional margin has been included in specifying maximum closure times. This margin permits identification of degraded valve performance, prior to exceeding the design closure times.

In order to assure that the doses that may result from a steam line break do not exceed the 10CFR100 guidelines, it is necessary that no fuel rod perforation resulting from the accident occur prior to closure of the main steam line isolation valves. Analyses indicate that fuel rod cladding perforations would be avoided for main steam valve closure times, including instrument delay, as long as 10.5 seconds.

These valves are highly reliable, have low service requirements and most are normally closed. The initiating sensors and associated trip channels are also checked to demonstrate the capability for automatic isolation. The test interval of once per operating cycle for automatic initiation results in a failure probability of 1.1×10^{-7} that a line will not isolate. More frequent testing for valve operability results in a greater assurance that the valve will be operable when needed.

The main steam line isolation valves are functionally tested on a more frequent interval to establish a high degree of reliability.

The primary containment is penetrated by several small diameter instrument lines connected to the reactor coolant system. Each instrument line contains a 0.25 inch restricting orifice inside the primary containment. A program for periodic testing and examination of the excess flow check valves is in place.

Primary Containment Painting

The interiors of the drywell and suppression chamber are painted to prevent rusting. The inspection of the paint during each major refueling outage assures the paint is intact. Experience at Pilgrim Station and other BWRs with this type of paint indicates that the inspection interval is adequate.

BASES:

3.7.B.1 and 4.7.B.1 - Standby Gas Treatment System

The Standby Gas Treatment System is designed to filter and exhaust the reactor building atmosphere to the stack during secondary containment isolation conditions. Upon containment isolation, both standby gas treatment fans are designed to start to bring the reactor building pressure negative so that all leakage should be in-leakage. After a preset time delay, the standby fan automatically shuts down so the reactor building pressure is maintained approximately 1/4 inch of water negative. Should one system fail to start, the redundant system is designed to start automatically. Each of the two trains has 100% capacity.

High Efficiency Particulate Air (HEPA) filters are installed before and after the charcoal adsorbers to minimize potential release of particulates to the environment and to prevent clogging of the iodine adsorbers. The charcoal adsorbers are installed to reduce the potential release of radioiodine to the environment. The in-place test results should indicate a system leak tightness of less than 1 percent bypass leakage for the charcoal adsorbers and a HEPA filter efficiency of at least 99 percent removal of cold DOP particulates. The laboratory carbon sample test results should indicate a methyl iodide removal efficiency of at least 95 percent for expected accident conditions. The specified efficiencies for the charcoal and particulate filters is sufficient to preclude exceeding 10 CFR 100 guidelines for the accidents analyzed. The analysis of the loss of coolant accident assumed a charcoal adsorber efficiency of 95% and TID 14844 fission product source terms, hence, installing two banks of adsorbers and filters in each train provides adequate margin. A 14 kW heater maintains relative humidity below 70% in order to ensure the efficient removal of methyl iodide on the impregnated charcoal adsorbers. Considering the relative simplicity of the heating circuit, the test frequency of once/operating cycle is adequate to demonstrate operability.

Air flow through the filters and charcoal adsorbers for 15 minutes each month assures operability of the system. Since the system heaters are automatically controlled, the air flowing through the filters and adsorbers will be $\leq$70% relative humidity and will have the desired drying effect.

Tests of impregnated charcoal identical to that used in the filters indicate that shelf life of five years leads to only minor decreases in methyl iodide removal efficiency. Hence, the frequency of laboratory carbon sample analysis is adequate to demonstrate acceptability. Since adsorbers must be be removed to perform this analysis this frequency also minimizes the system out of service time as a result of surveillance testing. In addition, although the halogenated hydrocarbon testing is basically a leak test, the adsorbers have charcoal of known efficiency and holding capacity for elemental iodine and/or methyl iodide, the testing also gives an indication of the relative efficiency of the installed system. The 31 day requirement for the ascertaining of test results ensures that the ability of the charcoal to perform its designed function is demonstrated and known in a timely manner.

The required Standby Gas Treatment System flow rate is that flow, less than or equal to 4000 CFM which is needed to maintain the Reactor Building at a 0.25 inch of water negative pressure under calm wind conditions. This capability is adequately demonstrated during Secondary Containment Leak Rate Testing performed pursuant to Technical Specification 4.7.C.1.c.

3.7.B.1 and 4.7.B.1 (continued)

The test frequencies are adequate to detect equipment deterioration prior to significant defects, but the tests are not frequent enough to load the filters or adsorbers, thus reducing their reserve capacity too quickly. The filter testing is performed pursuant to appropriate procedures reviewed and approved by the Operations Review Committee pursuant to Section 6 of these Technical Specifications. The in-place testing of charcoal filters is performed by injecting a halogenated hydrocarbon into the system upstream of the charcoal adsorbers. Measurements of the concentration upstream and downstream are made. The ratio of the inlet and outlet concentrations gives an overall indication of the leak tightness of the system. A similar procedure substituting dioctyl phthalate for halogenated hydrocarbon is used to test the HEPA filters.

Pressure drop tests across filter and adsorber banks are performed to detect plugging or leak paths though the filter or adsorber media. Considering the relatively short times the fans will be run for test purposes, plugging is unlikely and the test interval of once per operating cycle is reasonable.

System drains and housing gasket doors are designed such that any leakage would be in-leakage from the Standby Gas Treatment System Room. This ensures that there will be no bypass of process air around the filters or adsorbers.

Only one of the two Standby Gas Treatment Systems (SBGTS) is needed to maintain the secondary containment at a 0.25 inch of water negative pressure upon containment isolation. If one system is found to be inoperable, there is no immediate threat to the containment system performance and reactor operation or refueling activities may continue while repairs are being made. In the event one SBGTS is inoperable, the redundant system's active components will be tested within 2 hours. This substantiates the availability of the operable system and justifies continued reactor or refueling operations.

If both trains of SBGTS are inoperable, the plant is brought to a condition where the SBGTS is not required.

TABLE 4.8-2

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

Instrument	Instrument Check	Source Check	Channel Calibration	Channel Functional Test
1. Gross Beta or Gamma Radioactivity Monitors Providing Alarm and Automatic Isolation				
a. Liquid Radwaste Effluents Line	1	NA	Once per 18 months[2]	Quarterly
2. Flow Rate Measurement Devices				
a. Liquid Radwaste Effluent Line	1	NA	Once per 18 months	Quarterly

[1]During or prior to release via this pathway.

[2]Previously established calibration procedures will be used for these requirements.

TABLE 4.8-4
RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

Instrument	Instrument Check	Source Check	Instrument Calibration	Instrument Functional Test
1. Main Stack Effluent Monitoring System				
a. Noble Gas Activity Monitor (Two Channels)	Daily[1]	Monthly	Once per 18 Months[4]	Quarterly
b. Iodine Sampler Cartridge	NA	NA	NA	NA
c. Particulate Sampler Filter	NA	NA	NA	NA
d. Effluent System Flow Rate Measuring Device	Daily[1]	NA	Once per 18 Months	Quarterly
e. Sampler Flow Rate Measuring Device	Daily[1]	NA	Once per 18 Months	Quarterly
2. Reactor Building Ventilation Effluent Monitoring System				
a. Noble Gas Activity Monitor	Daily[1]	Monthly	Once per 18 Months[4]	Quarterly
b. Iodine Sampler Cartridge	NA	NA	NA	NA
c. Particulate Sampler Filter	NA	NA	NA	NA
d. Effluent System Flow Rate Measuring Device	Daily[1]	NA	Once per 18 Months	Quarterly

TABLE 4.8-4 (continued)
RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

Instrument	Instrument Check	Source Check	Instrument Calibration	Instrument Functional Test
e. Sampler Flow Rate Measuring Device	Daily[1]	NA	Once per 18 Months	Quarterly
3. Steam Jet Air Ejector Radioactivity Monitor				
a. Noble Gas Activity Monitor	Daily[3]	NA	Once per operating cycle[4]	Quarterly
4. Augmented Offgas Treatment System Explosive Gas Monitoring System				
a. Hydrogen Monitor	Daily[2]	NA	Quarterly[5]	Monthly

1 During releases via this pathway

2 During augmented offgas treatment system operation.

3 During operation of the steam jet air ejector.

4 Previously established calibration procedures will be used for these requirements.

5 Calibrate at 2 points with standard gas samples differing by at least 1% but not exceeding 4%.

LIMITING CONDITIONS FOR OPERATION

SURVEILLANCE REQUIREMENTS

4.9.A <u>Auxiliary Electrical Equipment Surveillance</u> (Cont'd)

1. Verifying de-energization of the emergency buses and load shedding from the emergency buses.

2. Verifying the diesel starts from ambient condition on the auto-start signal, energizes the emergency buses with permanently connected loads, energizes the auto-connected emergency loads through the load sequence, and operates for $\geq$ 5 minutes while its generator is loaded with the emergency loads.

   During performance of this surveillance verify that HPCI and RCIC inverters do not trip.

   The results shall be logged.

c. Once per operating cycle with the diesel loaded per 4.9.A.1.b verify that on diesel generator trip, secondary (offsite) AC power is automatically connected within 11.8 to 13.2 seconds | to the emergency service buses and emergency loads are energized through the load sequencer in the same manner as described in 4.9.A.1.b.1.

   The results shall be logged.

3.9.B Operation with Inoperable Equipment

Whenever the reactor is in Run Mode or Startup Mode with the reactor not in a Cold Condition, the availability of electric power shall be as specified in 3.9.B.1, 3.9.B.2, 3.9.B.3, 3.9.B.4, and 3.9.B.5.

1. From and after the date that incoming power is not available from the startup or shutdown transformer, continued reactor operation is permissible under this condition for seven days. During this period, both diesel generators and associated emergency buses must be demonstrated to be operable.

2. From and after the date that incoming power is not available from both startup and shutdown transformers, continued operation is permissible, provided both diesel generators and associated emergency buses are demonstrated to be operable, all core and containment cooling systems are operable, reactor power level is reduced to 25% of design and the NRC is notified within one (1) hour as required by 10CFR50.72.

3. From and after the date that one of the diesel generators or associated emergency bus is made or found to be inoperable for any reason, continued reactor operation is permissible in accordance with Specification 3.5.F if Specification 3.9.A.1 and 3.9.A.2.a are satisfied.

4. From and after the date that one of the diesel generators or associated emergency buses and either the shutdown or startup transformer power source are made

4.9.A Auxiliary Electrical Equipment Surveillance (Cont'd)

3. Emergency 4160V Buses A5-A6 Degraded Voltage Annunciation System.

   a. Once each operating cycle, calibrate the alarm sensor.

   b. Once each 31 days perform a channel functional test on the alarm system.

   c. In the event the alarm system is determined inoperable under 3.b above, commence logging safety related bus voltage every 30 minutes until such time as the alarm is restored to operable status.

4. RPS Electrical Protection Assemblies

   a. Each pair of redundant RPS EPAs shall be determined to be operable at least once per 6 months by performance of an instrument functional test.

   b. Once per 18 months, each pair of redundant RPS EPAs shall be determined to be operable by performance of an instrument calibration and by verifying tripping of the circuit breakers upon the simulated conditions for automatic actuation of the protective relays within the following limits: |

   Overvoltage $\leq$ 132 volts
   Undervoltage $\geq$ 108 volts
   Underfrequency $\geq$ $57H_z$

LIMITING CONDITION FOR OPERATION

SURVEILLANCE REQUIREMENTS

3.9 AUXILIARY ELECTRICAL SYSTEM (Cont)

B. Operation with Inoperable Equipment (Cont)

or found to be inoperable for any reason, continued reactor operation is permissible in accordance with Specification 3.5.F, provided either of the following conditions are satisfied:

a. The startup transformer and both offsite 345 kV transmission lines are available and capable of automatically supplying auxiliary power to the emergency 4160 volt buses.

b. A transmission line and associated shutdown transformer are available and capable of automatically supplying auxiliary power to the emergency 4160 volt buses.

5. From and after the date that one of the 125 or 250 volt battery systems is made or found to be inoperable for any reason, continued reactor operation is permissible during the succeeding three days within electrical safety considerations, provided repair work is initiated in the most expeditious manner to return the failed component to an operable state, and Specification 3.5.F is satisfied.

6. With the emergency bus voltage less than 3958.5V but above 3878.7V(excluding transients) during normal operation, transfer the safety related buses to the diesel generators. If grid voltage continues to degrade be in at least Hot Shutdown within the next 4 hours and in Cold Shutdown within the following 12 hours unless the grid conditions improve.

deliver full flow. Periodic testing of the various components, plus a functional test once per cycle, is sufficient to maintain adequate reliability.

Although station batteries will deteriorate with time, utility experience indicates there is almost no possibility of precipitous failure. The type of surveillance described in this specification has been demonstrated over the years to provide an indication of a cell becoming irregular or unserviceable long before it becomes a failure.

The Service Discharge Test provides indication of the batteries' ability to satisfy the design requirements (battery duty cycle) of the associated dc system. This test will be performed using simulated or actual loads at the rates and for the duration specified in the design load profile. A once per cycle testing interval was chosen to coincide with planned outages.

The Performance Discharge Test provides adequate indication and assurance that the batteries have the specified ampere hour capacity. The results of these tests will be logged and compared with the manufacturer's recommendations of acceptability. This test is performed once every five years in lieu of the Service Discharge test that would normally occur within that time frame.

The diesel fuel oil quality must be checked to ensure proper operation of the diesel generators. Water content should be minimized because water in the fuel could contribute to excessive damage to the diesel engine.

The electrical protection assemblies (EPAs) on the RPS inservice power supplies, either two motor generator sets or one motor generator and the alternative supply, consist of protective relays that trip their incorporated circuit breakers on overvoltage, undervoltage, or underfrequency conditions. There are two EPAs in series per power source. It is necessary to periodically test the relays to ensure the sensor is operating correctly and to ensure the trip unit is operable. Based on experience at conventional and nuclear power plants, a six-month frequency for the channel functional test is established. This frequency is consistent with the Standard Technical Specifications.

The EPAs of the power sources to the RPS shall be determined to be operable by performance of a channel calibration of the relays once per 18 months. During calibration, a transfer to the alternative power source is required; however, prior to switching to alternative feed, de-energization of the applicable MG set power source must be accomplished. This results in a half scram on the channel being calibrated until the alternative power source is connected and the half scram is cleared. Based on operating experience, drift of the EPA protective relays is not significant.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 151 TO FACILITY OPERATING LICENSE NO. DPR-35

BOSTON EDISON COMPANY

PILGRIM NUCLEAR POWER STATION

DOCKET NO. 50-293

1.0 INTRODUCTION

By letters dated June 7, 1993, August 9, 1993, and December 10, 1993, the Boston Edison Company (BECo) proposed changes to the Pilgrim Nuclear Power Station Technical Specifications (TSs) for Operating License No. DPR-35. The proposed changes revise TS surveillance test intervals from 18 to 24 months to accommodate a 24-month fuel cycle. The licensee evaluated the proposed changes in accordance with the guidance provided in NRC Generic Letter (GL) 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-month Fuel Cycle," dated April 2, 1991. The Pilgrim Nuclear Power Station (PNPS) has sufficient fuel loaded for a 24-month operating cycle.

On June 7, 1993, BECo proposed an increase to the surveillance intervals of certain instrumentation, related instrument calibration frequencies, and setpoints. The Instrumentation and Controls Branch (HICB) completed a review of this submittal and issued a Safety Evaluation (SE) on November 17, 1993. On August 9, 1993, BECo requested changes in some specific setpoints to accommodate a 24-month fuel cycle and addressed the design change mechanism to be used for effecting the setpoint changes. BECo also addressed associated procedural controls to be used to maintain control of the critical parameters identified in the calculations. HICB completed a review of the August 9, 1993, submittal and issued a SE on December 1, 1993. In the December 10, 1993 submittal BECo proposed changes in additional setpoints to accommodate the 24-month fuel cycle and provided justification for extending the surveillance interval for those components and systems that are not related to instrument setpoint changes. HICB completed a review of the December 10, 1993, submittal and issued a SE on February 17, 1994. This SE merges the three SEs in a single document.

2.0 BACKGROUND

Improved reactor fuels allow licensees to consider an increase in the duration of the fuel cycle for their facilities and longer fuel cycle increases the time interval between performance of TS surveillance requirements. GL 91-04 outlines generic guidance to licensees for providing the support required to change TS to allow 24 month surveillance intervals. GL 91-04 also includes requirements for evaluation of the impact on safety from an increase in surveillance interval. GL 91-04 further requires that a licensee should address the issue of instrumentation errors/setpoint methodology assumptions when proposing an extended instrumentation surveillance interval. Specifically, the licensee must evaluate the effects of an increased calibration interval on the instrument uncertainties, equipment qualification, and vendor maintenance requirements to ensure that an extended surveillance interval does not result in exceeding the assumptions stated in the safety analysis.

3.0 EVALUATION

3.1 Submittal dated June 7, 1993

BECo has established a Setpoint Control Program that includes instrumentation setpoint calculations to support PNPS TS changes required for a 24-month fuel cycle. A sample setpoint calculation, ABB Impell Project Number 25-226, for Reactor Vessel Low-Low Level Instruments LIS263-72A, B, C, and D, was submitted for staff review.

The licensee used the as-found/as-left instrument calibration data to statistically analyze the probability and confidence level drift errors for the level indication instruments (LISs). The 95%/95% probability and confidence level for the four level switches were statistically analyzed to determine if the data sets were normal or bounded by a normal curve. The results showed that none of the data exhibited time dependency and sufficient data were bounded by the 95% probability/95% confidence values that established that these data are valid estimates of instrument drift. This analysis included 120-day drift data from July 2, 1987, through October 29, 1992, for the LISs; however, the licensee used the manufacturer's drift specification of transmitters because there were not enough data points for a valid statistical analysis of transmitters at this time.

The licensee proposed to change the reactor low-low level trip level setting from -49" to -46" (79.96" above top of active fuel). This trip setpoint was determined from the normal operation lower limit 20" and included errors due to sensor drift, rack equipment drift, sensor tolerance, and rack equipment tolerance. However, after applying additional allowance for errors associated with environmental conditions, circuit leakage, process calibration, rack equipment, and sensor, the analytical limit for reactor low-low level became -56.9" from instrument zero.

BECo requested General Electric Company (GE) to provide a report for the justification of changing the analytical limit for low-low reactor water level from its current -49" from instrument zero to -57" from instrument zero. GE provided a Summary Report (DRF A00-03983) for the justification for changing the analytical limit for low-low reactor water level instruments that provide initiation of the following safety systems:

- o High-pressure coolant injection and reactor core isolation cooling,
- o Emergency diesel generators,
- o Low-pressure coolant injection and Core Spray,
- o Main steam isolation valve closure and isolation valves for drywell equipment,
- o ADS and bypass timer,
- o Recirculation pump trip

The impact of the change in the analytical limits for the above safety system functions for transients, loss-of-coolant accident, breaks outside primary containment and containment isolation were evaluated and determined by GE not to have any adverse impact on plant safety.

The licensee's analysis of the effect of instrument drift requires the following setpoint changes to ensure the extended interval does not result in exceeding an instrument's acceptable setpoint tolerance.

o Reactor Protection System (RPS) (Table 3.1.1)

	from	to
- High Reactor Pressure	1085 psig	1063.5 psig
- High Drywell Pressure	2.5 psig	2.22 psig
- Reactor Low water Level	9 inch	11.7 inch

o Primary Containment Isolation (PCIS) (Table 3.2.A)

- Reactor Low Water Level	9 inch	11.7 inch
- Reactor Low-Low Water Level	-49 inch	-46.3 inch
- Reactor High Water Level	48 inch	45.3 inch
- High Drywell Pressure	2.5 psig	2.22 psig
- Low Pressure Main Steam Line	880 psig	810 psig

o Core Spray and Containment Cooling Systems (Table 3.2.B)

- Reactor Low-Low Water Level	-49 inch	-46.3 inch
- Reactor High Water Level	48 inch	45.3 inch

The following changes were made to NOTES FOR TABLE 3.1.1 RPS:

NOTE 3. Permission to bypass [main condenser low vacuum trip and main steam line isolation valve closure trip] when reactor pressure is 600 psig is changed to 576 psig.

The setpoint change to the turbine first stage pressure bypass in the following note was made to assure a reactor trip at a lower load rejection to prevent the reactor vessel safety valves from operating.

NOTE 4. Permission to bypass [turbine control valve fast closure trip and turbine stop valve closure trip] when turbine first stage pressure is less than 305 psig is changed to 112 psig.

The licensee made the necessary changes to the Table Notes and the BASES sections associated with the above Tables. The Table 3.2 low pressure main steam line setpoint change was submitted in BECo's letter dated May 20, 1993, (Ref. 3). Reactor Protection System (Scram) Instrument Calibration for average power range monitor high flux, output signal, and flow bias signal calibration frequency will remain at 18 months.

The licensee proposes to change following instrument function test frequency from 1 month to 3 months.

Table 4.2.A Minimum Test and Calibration Frequency for Primary Containment Isolation System

- o Reactor low-low water level
- o Reactor high water level
- o Main steam low pressure

Table 4.2.B Minimum Test and Calibration Frequency for Core Standby Cooling Systems

- o Reactor Water Level

The licensee has identified that the basis for change of test frequency for these instruments from 1 month to 3 months is their failures relative to the hours in service for identical components. The licensee used Figure 4.1.1, "Graphical Aid in the Selection of an Adequate Interval Between Test" to determine the 3-month test frequency. This figure is a plot of the number of unsafe failures verse exposure hours [M FACTOR] (number of identical components times instrument operating hours) for various test time intervals. The licensee has provided a safety analysis which determined that operating the plant with the proposed changes to the PNPS TSs will not involve a significant increase in the probability or consequence of an accident previously identified, create the possibility of a new or different kind of accident from any accident previously analyzed, or involve a significant reduction in the margin of safety.

3.2 Submittal dated August 9, 1993

BECo has established a Setpoint Control Program (SCP) that includes instrumentation setpoint calculations to support PNPS technical support changes required for a 24-month fuel cycle. A sample setpoint calculation, ABB Impell Project Number 25-226, for reactor vessel low-low level instruments LIS263-72A, B, C, and D, was submitted on June 7, 1993, for the staff's review. The staff has found acceptable the licensee's method of determining instrument drift error and application of the SCP.

The licensee analysis of the effect of instrument drift requires the following setpoint changes to ensure that the extended interval does not result in exceeding an instrument's acceptable setpoint tolerance.

o Reactor Protection System (RPS) (Table 3.1.1)

	from	to
- Scram Discharge Instrument Volume (SDIV)		
SDIV High Water Level	39 gal	38 gal
- Main Steam Line High Radiation	7x Normal full Power Background	5x

o Core and Containment Cooling Systems (Table 3.2.B)

	from	to
-Reactor Hi water Lv	307 " above vessel zero	-151 " indicated level
-Cont Hi Press	1 less than p less than 2 psig	1.55 less than p less than 1.82 psig

Additional Remarks : Instrumentation set to trip before 1.82 increasing and reset before 1.55 decreasing.

-Hi Drywell Press	2.5 psig	2.22 psig

o Control Rod Block Instrumentation Setpoints Table 3.2.C-2

-SDIV High Water Level,	18 gal	17 gal

o Instrumentation that Initiates Recirculation Pump Trip and Alternate Rod insertion Table 3.2-G

-Hi Reactor Dome Press	1175 + or - 15 psig	1175 + or - 5 psig
-Low-Low Reactor Water Lv	77.26 " above the top of the active fuel	-46.3" indicated Lv

The licensee made the necessary changes to the Table Notes and the BASES sections associated with the above Tables.

The licensee has provided a safety analysis which determined that operating the plant with the proposed changes to the PNPS TSs will not involve a significant increase in the probability or consequence of an accident previously identified, create the possibility of a new or different kind of accident from any accident previously analyzed, or involve a significant reduction in the margin of safety.

3.3 Submittal Dated December 10, 1993

BECo's evaluation was based on the use of historical plant maintenance and surveillance data to support the proposed 24-month surveillance intervals.

<u>Reactor Protection System</u>

TS Table 3.1.1, Item 1 No text change

The reactor mode switch has a specified test interval of once every refueling outage. Extending to a 24-month refueling cycle would result in an increase in the test interval for the reactor mode switch from once every 18 months to once every 24 months.

Logic System Functional Test

	from	to
TS Table 4.2.A, Items 1-5	Once/18 months	Once/operating cycle
TS Table 4.2.B, Items 1-9	Once/18 months	Once/operating cycle
TS Table 4.2.C, System Logic Check	Once/18 months	Once/operating cycle
TS Table 4.2.D, Items 1 and 2	Once/18 months	Once/operating cycle

Logic system functional tests are required to be performed once every 18 months. Changing to a test interval of once per operating cycle would result in an increase in the test interval from once every 18 months to once every 24 months.

TS Table 4.2.G — No text change

The reactor high pressure and reactor low-low water level instrumentation have a specified test interval of once during each refueling outage. Extending to a 24-month refueling cycle would result in an increase in the test interval for the reactor high pressure and reactor low-low water level instrumentation from once every 18 months to once every 24 months.

TS 4.8.H — No text change

The mechanical vacuum pump has a specified test interval of once during each operating cycle. Extending to a 24-month refueling cycle would result in an increase in the test interval for the mechanical vacuum pump from once every 18 months to once every 24 months.

Simulated Automatic Actuations

TS 4.5.A.1.a	No text change
TS 4.5.A.3.a	No text change
TS 4.5.C.1.a	No text change
TS 4.5.D.1.a	No text change
TS 4.5.E.1.a	No text change
TS 4.7.A.2.b.1.a	No text change

Surveillance of simulated automatic actuations are required to be performed prior to startup following a refueling outage. Extending to a 24-month refueling cycle would result in an increase in the test interval for the simulated automatic actuations from once every 18 months to once every 24 months.

Core Standby Cooling System

	from	to
TS Table 4.2.B.7	Once/operating cycle	Once/18 months

The core spray sparger D/P (differental pressure) has a specified test interval of once every operating cycle. Changing the surveillance interval to once every 18 months would not change the amount of time between tests of the core spray sparger D/P.

Reactivity Control

TS 4.3.A.1 No text change

Sufficient control rods are required to be withdrawn following a refueling outage when core alterations are performed to demonstrate that the core can be made subcritical at any time. Because this surveillance is event dependent and not based on time, extending the refueling cycle length does not affect the validity of this demonstration.

Control Rod Drives

TS 4.3.B.1.a No text change
TS 4.3.B.1.b No text change
TS 4.3.C.1 No text change

Control rod coupling integrity is verified when rods are withdrawn for the first time after a refueling outage. Because this surveillance is event dependent and not based on time, extending the refueling cycle length does not affect the validity of this verification.

Standby Liquid Control System

TS 4.4.C.4 No text change

The standby liquid control system solution B^{10} enrichment is tested anytime boron is added and during each refueling outage. Because this surveillance is event dependent and not based on time, extending the refueling cycle length does not affect the validity of this test.

HPCI and RCIC Flow Rate

TS 4.5.C.1.e No text change
TS 4.5.D.1.e No text change

The HPCI pump and RCIC pump have a specified flow rate test interval of once during each operating cycle. Extending to a 24-month refueling cycle would result in an increase in the test interval for the HPCI and RCIC pumps from once every 18 months to once every 24 months.

Automatic Depressurization System

TS 4.5.E.1.b No text change

Each automatic depressurization system relief valve is required to be manually opened once during each operating cycle. Extending to a 24-month refueling cycle would result in an increase in the test interval for the relief valves from once every 18 months to once every 24 months.

Leakage Detection Systems

	from	to
TS 4.6.C.2.a.2	Once/18 months	Once/operating cycle
TS 4.6.C.2.b.3	Once/18 months	Once/operating cycle

The drywell sump monitoring system and the drywell atmospheric radioactivity monitoring system are required to be calibrated at least once every 18 months. Changing to a test interval of once per operating cycle would result in an increase in the test interval for the drywell sump monitoring system and the drywell atmospheric radioactivity monitoring system from once every 18 months to once every 24 months.

Safety and Relief Valves

TS 4.6.D.2 No text change

At least one of the relief/safety valves is required to be disassembled and inspected each refueling outage. Extending to a 24-month refueling cycle would result in an increase in the disassembly interval for the relief/safety valves from once every 18 months to once every 24 months.

Shock Suppressors (Snubbers)

	from	to
TS 4.6.I	Once/18 months	Once/operating cycle

Snubbers are required to be inspected at least once every 18 months. Changing to an inspection interval of once per operating cycle would result in an increase in the surveillance interval for the snubbers from once every 18 months to once every 24 months.

	from	to
TS 4.6.I.2.A	Once/18 months	Once/operating cycle

A representative sample of snubbers are required to be functionally tested at least once every 18 months. Changing to a test interval of once per operating cycle would result in an increase in the surveillance interval for the snubbers from once every 18 months to once every 24 months.

TS 4.6.I.3.B No text change

The installation and maintenance records for each safety related snubber is required to be reviewed at least once per cycle. Extending to a 24-month refueling cycle would result in an increase in the review interval for the snubbers from once every 18 months to once every 24 months.

Suppression Chamber and Drywell Surface

TS 4.7.A.1.e No text change
TS 4.7.A.2.d No text change

The suppression chamber, drywell, and torus interiors are required to be inspected every refueling outage. Extending to a 24-month refueling cycle would result in an increase in the surveillance interval for the suppression chamber, drywell, and torus interiors from once every 18 months to once every 24 months.

Containment Atmospheric Dilution System

TS 4.7.A.7.a No text change

The post-LOCA containment atmosphere dilution system is required to be functionally tested once per operating cycle. Extending to a 24-month refueling cycle would result in an increase in the surveillance interval for the post-LOCA dilution system from once every 18 months to once every 24 months.

Standby Gas Treatment System

	from	to
TS 4.7.B.1.a (1)	Once/18 months	Once/operating cycle
TS 4.7.B.1.a (2)	Once/18 months	Once/operating cycle
TS 4.7.B.1.a (3)	Once/18 months	Once/operating cycle
TS 4.7.B.1.a (41)	Once/18 months	Once/operating cycle

The standby gas treatment system is required to be tested once every 18 months. Changing to a test interval of once per operating cycle would result in an increase in the surveillance interval for the standby gas treatment system from once every 18 months to once every 24 months.

Control Room High Efficiency Air Filtration System

	from	to
TS 4.7.B.2.a	once/18 months	once/operating cycle
TS 4.7.B.2.b	once/18 months	once/operating cycle
TS 4.7.B.2.c	once/18 months	once/operating cycle
TS 4.7.B.2.d	once/18 months	once/operating cycle

The control room high efficiency air filtration system is required to be tested once every 18 months. Changing to a test interval of once per operating cycle would result in an increase in the surveillance interval for the standby gas treatment system from once every 18 months to once every 24 months.

Secondary Containment

TS 4.7.C.1.c	No text change

The secondary containment capability to maintain 1/4 inch of water vacuum is required to be demonstrated at each refueling outage prior to refueling. Extending to a 24-month refueling cycle would result in an increase in the demonstration interval for the secondary containment's capability to maintain a vacuum from once every 18 months to once every 24 months.

Auxiliary Electrical System

TS 4.9.A.1	No text change
TS 4.9.A.2	No text change

The diesel generators and the station and switchyard batteries are required to be tested once per operating cycle. Extending to a 24-month refueling cycle would result in an increase in the surveillance interval for the diesel generators and the station and switchyard batteries from once every 18 months to once every 24 months.

Core Alterations

TS 4.10	No text change

The refueling interlocks and the source range monitors are required to be functionally tested prior to any fuel handling with the head off the reactor vessel. Extending to a 24-month refueling cycle would result in an increase in the test interval for the refueling interlocks and the source range monitors from once every 18 months to once every 24 months.

Alternate Shutdown Panels

TS 4.12 No text change

The alternate shutdown panels are required to be demonstrated OPERABLE once each cycle. Extending to a 24-month refueling cycle would result in an increase in the demonstration interval for the alternate shutdown panels from once every 18 months to once every 24 months.

Correction of Editorial Errors and Addition of Changes

The licensee provided corrections of editorial errors that were contained in the June 7, 1993, and the August 9, 1993 submittals. These corrections were to the following TS and BASES:

TS 3.1.1, page 27
Bases 3.1, pages 39 and 40
TS 3.2.A, page 46a
TS 3.2.B, page 47
TS 4.2.B, page 61
Bases 3.2, page 68

The licensee made the necessary changes to the Table Notes and the BASES sections associated with the above Tables.

The licensee has provided a safety analysis which determined that operating the plant with the proposed changes to the PNPS TSs will not involve a significant increase in the probability or consequence of an accident previously identified, create the possibility of a new or different kind of accident from any accident previously analyzed, or involve a significant reduction in the margin of safety.

4.0 CONCLUSION

The licensee has demonstrated that the proposed changes have a small net effect on safety, that historical plant maintenance and surveillance data support the proposed extended surveillance intervals, and that the assumptions in the plant licensing basis are still bounding with the incorporation of a 24-month surveillance interval. BECo has analyzed instrument drift error associated with the 24-month refuel cycle and adjusted trip setpoints in accordance with their Setpoint Control Program. The licensee provided a safety analysis of these setpoint changes and found no significant effect upon safety. The staff reviewed the licensee's proposed changes to the TSs and find these changes acceptable. We, therefore, find the proposed TS changes to increase the surveillance interval from 18 to 24 months acceptable.

5.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Massachusetts State Official was notified of the proposed issuance of the amendment. The State official had no comments.

6.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and changes surveillance requirements. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration, and there has been no public comment on such finding (59 FR 2863). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

7.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

8.0 REFERENCES

1. Letter from E.T. Boulette, Senior Vice President - Nuclear, Boston Edison Company to NRC, "Proposed Changes to Technical Specifications: Request for Changes Supporting a 24 Month Fuel Cycle," dated June 7, 1993.

2. Generic Letter 91-04 from James G. Partlow, Associate Director for Projects - Office of Nuclear Reactor Regulation - NRC, to All Holders of Operating Licenses or Construction Permits for Nuclear Power Reactors "Guidance on Preparation of a License Amendment Request for Changes in Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991.

3. Letter from E.T. Boulette, Senior Vice President - Nuclear, Boston Edison Company to NRC, "Proposed Changes to Technical specifications: Main Steam Isolation Valve Turbine Inlet Low-Pressure Setpoint," dated May 20, 1993.

4. Letter from E.T. Boulette, Senior Vice President - Nuclear, Boston Edison Company to NRC, "Proposed Changes to Technical Specifications: Request for Changes Supporting a 24 Month Fuel Cycle," (Submittal 2), dated August 9, 1993.

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