June 22, 1989

Docket No.: 50-352

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Mr. George A. Hunger, Jr.
Director-Licensing
Philadelphia Electric Company
Correspondence Control Desk
P. O. Box 7520
Philadelphia, Pennsylvania 19101

Dear Mr. Hunger:

SUBJECT: CLARIFICATION OF TECHNICAL SPECIFICATIONS (TAC NO. 61000)

RE: LIMERICK GENERATING STATION, UNIT 1

The Commission has issued the enclosed Amendment No. 29 to Facility Operating License No. NPF-39 for the Limerick Generating Station, Unit 1. This amendment consists of changes to the Technical Specifications (TSs) in response to your application dated February 14, 1986.

This amendment makes administrative changes to the Technical Specifications (TSs) to achieve consistency, remove outdated material, make minor text changes and correct errors.

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

Sincerely,

Original signed by
Richard J. Clark

Richard J. Clark, Project Manager
Project Directorate I-2
Division of Reactor Projects I/II
Office of Nuclear Reactor Regulation

Enclosures:
1. Amendment No. 29 to License No. NPF-39
2. Safety Evaluation

cc w/enclosures:
See next page

DF01
1/1

[HUN LETTER]

*Previously concurred

PDI-2/LA	PDI-2/PM*	OGC*	PDI-2/D
MO'Brien	RClark:tr	SHLewis	WButler
6/1/89	05/31/89	06/05/89	6/21/89

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

June 22, 1989

Docket No.: 50-352

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Philadelphia Electric Company
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P. O. Box 7520
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See next page

Mr. George A. Hunger, Jr.
Philadelphia Electric Company

Limerick Generating Station
Units 1 & 2

cc:

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

PHILADELPHIA ELECTRIC COMPANY

DOCKET NO. 50-352

LIMERICK GENERATING STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 29
License No. NPF-39

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

   A. The application for amendment by Philadelphia Electric Company (the licensee) dated February 14, 1986, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   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 2.C.(2) of Facility Operating License No. NPF-39 is hereby amended to read as follows:

   Technical Specifications

   The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 29 , are hereby incorporated into this license. Philadelphia Electric Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective within 30 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/S/

Walter R. Butler, Director
Project Directorate I-2
Division of Reactor Projects I/II

Attachment:
Changes to the Technical
Specifications

Date of Issuance: June 22, 1989

Previously concurred*

PDI-2/LA*	PDI-2/PM*	OGC*	PDI-2/D*
MO'Brien	RClark:tr	SHLewis	WButler
06/22/89	05/31/89	06/05/89	06/07/89

3. This license amendment is effective within 30 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Walter R. Butler

Walter R. Butler, Director
Project Directorate I-2
Division of Reactor Projects I/II

Attachment:
Changes to the Technical
Specifications

Date of Issuance: June 22, 1989

ATTACHMENT TO LICENSE AMENDMENT NO. 29

FACILITY OPERATING LICENSE NO. NPF-39

DOCKET NO. 50-352

Replace the following pages of the Appendix A Technical Specifications with the attached page. The revised pages are identified by Amendment number and contain vertical lines indicating the area of change. Overleaf pages are provided to maintain document completeness.*

Remove	Insert
3/4 1-1	3/4 1-1*
3/4 1-2	3/4 1-2
3/4 3-7	3/4 3-7*
3/4 3-8	3/4 3-8
3/4 3-21	3/4 3-21
3/4 3-22	3/4 3-22
3/4 3-23	3/4 3-23
3/4 3-24	3/4 3-24*
3/4 3-85	3/4 3-85
3/4 3-86	3/4 3-86*
3/4 3-93	3/4 3-93*
3/4 3-94	3/4 3-94
3/4 3-99	3/4 3-99*
3/4 3-100	3/4 3-100
3/4 4-19	3/4 4-19
3/4 4-20	3/4 4-20*
3/4 5-3	3/4 5-3*
3/4 5-4	3/4 5-4
3/4 5-5	3/4 5-5
3/4 5-6	3/4 5-6*
3/4 6-9	3/4 6-9
3/4 6-10	3/4 6-10

Remove	Insert
3/4 6-11	3/4 6-11*
3/4 6-12	3/4 6-12
3/4 6-17	3/4 6-17
3/4 6-18	3/4 6-18
3/4 6-23	3/4 6-23
3/4 6-24	3/4 6-24*
3/4 6-41	3/4 6-41*
3/4 6-42	3/4 6-42
3/4 6-47	3/4 6-47
3/4 6-48	3/4 6-48*
3/4 6-52	3/4 6-52
-	-
3/4 7-9	3/4 7-9
3/4 7-10	3/4 7-10
3/4 7-21	3/4 7-21*
3/4 7-22	3/4 7-22
B 3/4 6-1	B 3/4 6-1*
B 3/4 6-2	B 3/4 6-2
6-13	6-13*
6-14	6-14
6-15	6-15*
6-16	6-16

1.0 DEFINITIONS

The following terms are defined so that uniform interpretation of these specifications may be achieved. The defined terms appear in capitalized type and shall be applicable throughout these Technical Specifications.

ACTION

1.1 ACTION shall be that part of a Specification which prescribes remedial measures required under designated conditions.

AVERAGE PLANAR EXPOSURE

1.2 The AVERAGE PLANAR EXPOSURE shall be applicable to a specific planar height and is equal to the sum of the exposure of all the fuel rods in the specified bundle at the specified height divided by the number of fuel rods in the fuel bundle.

AVERAGE PLANAR LINEAR HEAT GENERATION RATE

1.3 The AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) shall be applicable to a specific planar height and is equal to the sum of the LINEAR HEAT GENERATION RATES for all the fuel rods in the specified bundle at the specified height divided by the number of fuel rods in the fuel bundle.

CHANNEL CALIBRATION

1.4 A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel output such that it responds with the necessary range and accuracy to known values of the parameter which the channel monitors. The CHANNEL CALIBRATION shall encompass the entire channel including the sensor and alarm and/or trip functions, and shall include the CHANNEL FUNCTIONAL TEST. The CHANNEL CALIBRATION may be performed by any series of sequential, overlapping or total channel steps such that the entire channel is calibrated.

CHANNEL CHECK

1.5 A CHANNEL CHECK shall be the qualitative assessment of channel behavior during operation by observation. This determination shall include, where possible, comparison of the channel indication and/or status with other indications and/or status derived from independent instrument channels measuring the same parameter.

CHANNEL FUNCTIONAL TEST

1.6 A CHANNEL FUNCTIONAL TEST shall be:

a. Analog channels - the injection of a simulated signal into the channel as close to the sensor as practicable to verify OPERABILITY including alarm and/or trip functions and channel failure trips.

b. Bistable channels - the injection of a simulated signal into the sensor to verify OPERABILITY including alarm and/or trip functions.

The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping or total channel steps such that the entire channel is tested.

3/4.1.2 REACTIVITY ANOMALIES

LIMITING CONDITION FOR OPERATION

3.1.2 The reactivity equivalence of the difference between the actual ROD DENSITY and the predicted ROD DENSITY shall not exceed 1% $\Delta k/k$.

APPLICABILITY: OPERATIONAL CONDITION 1 and 2.

ACTION:

With the reactivity equivalence difference exceeding 1% $\Delta k/k$:

a. Within 12 hours perform an analysis to determine and explain the cause of the reactivity difference; operation may continue if the difference is explained and corrected.

b. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.1.2 The reactivity equivalence of the difference between the actual ROD DENSITY and the predicted ROD DENSITY shall be verified to be less than or equal to 1% $\Delta k/k$:

a. During the first startup following CORE ALTERATIONS, and

b. At least once per 31 effective full power days during POWER OPERATION.

c. The provisions of Specification 4.0.4 are not applicable.

TABLE 4.3.1.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION[a]	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. Intermediate Range Monitors:				
a. Neutron Flux - High	S/U,S(b)	S/U(c), W	R	2
	S	W(j)	R	3, 4, 5
b. Inoperative	N.A.	W(j)	N.A.	2, 3, 4, 5
2. Average Power Range Monitor[f]:				
a. Neutron Flux -	S/U,S(b)	S/U(c), W	SA	2
Upscale, Setdown	S	W(j)	SA	3, 5
b. Neutron Flux - Upscale				
1) Flow Biased	S,D(g)	S/U(c), W	W(d)(e),SA,	1
2) High Flow Clamped	S	S/U(c), W	W(d)(e), SA	1
c. Inoperative	N.A.	W(j)	N.A.	1, 2, 3, 5
d. Downscale	S	W	SA	1
3. Reactor Vessel Steam Dome Pressure - High	S	M	R	1, 2(h)
4. Reactor Vessel Water Level - Low, Level 3	S	M	R	1, 2
5. Main Steam Line Isolation Valve - Closure	N.A.	M	R	1
6. Main Steam Line Radiation - High	S	M	R	1, 2(h)
7. Drywell Pressure - High	S	M	R	1, 2

TABLE 4.3.1.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
8. Scram Discharge Volume Water Level - High				
a. Level Transmitter	S	M	R	1, 2, 5[i]
b. Float Switch	N.A.	M	R	1, 2, 5[i]
9. Turbine Stop Valve - Closure	N.A.	M	R	1
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	N.A.	M	R	1
11. Reactor Mode Switch Shutdown Position	N.A.	R	N.A.	1, 2, 3, 4, 5
12. Manual Scram	N.A.	M	N.A.	1, 2, 3, 4, 5

(a) Neutron detectors may be excluded from CHANNEL CALIBRATION.
(b) The IRM and SRM channels shall be determined to overlap for at least ½ decades during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for at least ½ decades during each controlled shutdown, if not performed within the previous 7 days.
(c) Within 24 hours prior to startup, if not performed within the previous 7 days.
(d) This calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER ≥ 25% of RATED THERMAL POWER. Adjust the APRM channel if the absolute difference is greater than 2% of RATED THERMAL POWER. Any APRM channel gain adjustment made in compliance with Specification 3.2.2 shall not be included in determining the absolute difference.
(e) This calibration shall consist of the adjustment of the APRM flow biased channel to conform to a calibrated flow signal.
(f) The LPRMs shall be calibrated at least once per 1000 effective full power hours (EFPH) using the TIP system.
(g) Verify measured core flow (total core flow) to be greater than or equal to established core flow at the existing loop flow (APRM % flow). During the startup test program, data shall be recorded for the parameters listed to provide a basis for establishing the specified relationships. Comparisons of the actual data in accordance with the criteria listed shall commence upon the conclusion of the startup test program.
(h) This function is not required to be OPERABLE when the reactor pressure vessel head is removed per Specification 3.10.1.
(i) With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.
(j) If the RPS shorting links are required to be removed per Specification 3.9.2, they may be reinstalled for up to 2 hours for required surveillance. During this time, CORE ALTERATIONS shall be suspended, and no control rod shall be moved from its existing position.

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
6. PRIMARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level		
1. Low, Low - Level 2	≥ -38 inches*	≥ -45 inches
2. Low, Low, Low, Level 1	≥ -129 inches*	≥ -136 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. North Stack Effluent Radiation - High	≤ 2.1 μCi/cc	≤ 4.0 μCi/cc
d. Deleted		
e. Reactor Enclosure Ventilation Exhaust Duct - Radiation - High	≤ 1.35 mR/h	≤ 1.5 mR/h
f. Outside Atmosphere To Reactor Enclosure Δ Pressure - Low	≥ 0.1" of H_2O	≥ 0.0" of H_2O
g. Outside Atmosphere to Refueling Area Δ Pressure - Low	≥ 0.1" of H_2O	≥ 0.0" of H_2O
h. Drywell Pressure - High/ Reactor Pressure - Low	≤ 1.68 psig/ ≥ 455 psig (decreasing)	≤ 1.88 psig/ ≥ 435 psig (decreasing)
i. Primary Containment Instrument Gas to Drywell Δ Pressure-Low	≥ 2.0 psig	≥ 1.9 psig
j. Manual Initiation	N.A.	N.A.

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
7. SECONDARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level - Low, Low - Level 2	≥ -38 inches*	≥ -45 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c.1. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High	≤ 2.0 mR/h	≤ 2.2 mR/h
2. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High	≤ 2.0 mR/h	≤ 2.2 mR/h
d. Reactor Enclosure Ventilation Exhaust Duct Radiation - High	≤ 1.35 mR/h	≤ 1.5 mR/h
e. Outside Atmosphere To Reactor Enclosure Δ Pressure - Low	≥ 0.1" of H_2O	≥ 0.0" of H_2O
f. Outside Atmosphere To Refueling Area Δ Pressure - Low	≥ 0.1" of H_2O	≥ 0.0" of H_2O
g. Reactor Enclosure Manual Initiation	N.A.	N.A.
h. Refueling Area Manual Initiation	N.A.	N.A.

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

**The low setpoints are for the RWCU Heat Exchanger Rooms; the high setpoints are for the pump rooms.

TABLE 3.3.2-3

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
1. MAIN STEAM LINE ISOLATION	
a. Reactor Vessel Water Level	
1) Low, Low - Level 2	$\leq 13^{(a)}$**
2) Low, Low, Low - Level 1	≤ 1.0*/$\leq 13^{(a)}$**
b. Main Steam Line Radiation - High[(b)]	≤ 1.0*/$\leq 13^{(a)}$**
c. Main Steam Line Pressure - Low	≤ 1.0*/$\leq 13^{(a)}$**
d. Main Steam Line Flow - High	≤ 0.5*/$\leq 13^{(a)}$**
e. Condenser Vacuum - Low	N.A.
f. Outboard MSIV Room Temperature - High	N.A.
g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High	N.A.
h. Manual Initiation	N.A.
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION	
a. Reactor Vessel Water Level Low - Level 3	$\leq 13^{(a)}$
b. Reactor Vessel (RHR Cut-In Permissive) Pressure - High	N.A.
c. Manual Initiation	N.A.
3. REACTOR WATER CLEANUP SYSTEM ISOLATION	
a. RWCS Δ Flow - High	≤ 13##
b. RWCS Area Temperature - High	N.A.
c. RWCS Area Ventilation Δ Temperature - High	N.A.
d. SLCS Initiation	N.A.
e. Reactor Vessel Water Level - Low, Low - Level 2	$\leq 13^{(a)}$
f. Manual Initiation	N.A.

TABLE 3.3.2-3 (Continued)

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION	
a. HPCI Steam Line Δ Pressure - High	≤ 13[a]
b. HPCI Steam Supply Pressure - Low	≤ 13[a]
c. HPCI Turbine Exhaust Diaphragm Pressure - High	N.A.
d. HPCI Equipment Room Temperature - High	N.A.
e. HPCI Equipment Room Δ Temperature - High	N.A.
f. HPCI Pipe Routing Area Temperature - High	N.A.
g. Manual Initiation	N.A.
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION	
a. Reactor Steam Line Δ Pressure - High	≤ 13[a]
b. RCIC Steam Supply Pressure - Low	≤ 13[a]
c. RCIC Turbine Exhaust Diaphragm Pressure - High	N.A.
d. RCIC Equipment Room Temperature - High	N.A.
e. RCIC Equipment Room Δ Temperature - High	N.A.
f. RCIC Pipe Routing Area Temperature - High	N.A.
g. Manual Initiation	N.A.

TABLE 3.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	REQUIRED NUMBER OF CHANNELS	MINIMUM CHANNELS OPERABLE	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. Reactor Vessel Pressure	2	1	1,2	80
2. Reactor Vessel Water Level	2	1	1,2	80
3. Suppression Chamber Water Level	2	1	1,2	80
4. Suppression Chamber Water Temperature	8, 6 locations	6, 1/location	1,2	80
5. Suppression Chamber Air Temperature	1	1	1,2	80
6. Drywell Pressure	2	1	1,2	80
7. Drywell Air Temperature	1	1	1,2	80
8. Drywell Oxygen Concentration Analyzer	2	1	1,2	80
9. Drywell Hydrogen Concentration Analyzer	2	1	1,2	80
10. Safety/Relief Valve Position Indicators	1/valve	1/valve	1,2	80
11. Primary Containment Post-LOCA Radiation Monitors	4	2	1,2,3	81
12. North Stack Wide Range Accident Monitor**	3*	3*	1,2,3	81
13. Neutron Flux	2	1	1,2	80

Table 3.3.7.5-1 (Continued)

ACCIDENT MONITORING INSTRUMENTATION

TABLE NOTATIONS

*Three noble gas detectors with overlapping ranges (10^{-7} to 10^{-1}, 10^{-4} to 10^{2}, 10^{-1} to 10^{5} μCi/cc).
**High range noble gas monitor.

ACTION STATEMENTS

ACTION 80 -

a. With the number of OPERABLE accident monitoring instrumentation channels less than the Required Number of Channels shown in Table 3.3.7.5-1, restore the inoperable channel(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

b. With the number of OPERABLE accident monitoring instrumentation channels less than the Minimum Channels OPERABLE requirements of Table 3.3.7.5-1, restore the inoperable channel(s) to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours.

ACTION 81 - With the number of OPERABLE accident monitoring instrumentation channels less than required by the Minimum Channels OPERABLE requirement, initiate the preplanned alternate method of monitoring the appropriate parameters within 72 hours, and

a. Either restore the inoperable channel(s) to OPERABLE status within 7 days of the event, or

b. Prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within 14 days following the event outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system to OPERABLE status.

TABLE 3.3.7.9-1

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION				TOTAL NUMBER OF INSTRUMENTS*		
FIRE ZONE	STRUCTURE	ELEV.	AREA	HEAT (x/y)	SMOKE (x/y)	FLAME (x/y)
1L	Control	200'	Control Structure Chillers and Chilled Water Pump Area 258	NA	3/0	NA
1M	Control	200'	Control Structure Chillers and Chilled Water Pump Area 263	NA	3/0	NA
2	Control	217'	13-kV Switchgear Area 336	NA	34/0	NA
3	Control	217'	Battery Room 323 (1D)	1/0	1/0	NA
4	Control	217'	Battery Room 324 (1C)	1/0	1/0	NA
7	Control	239'	Corridor 437	NA	5/0	NA
8	Control	239'	Battery Room 425 (1B1/1B2)	1/0	2/0	NA
9	Control	239'	Battery Room 436 (1A1/1A2)	1/0	2/0	NA
12	Control	239'	4-kV Switchgear Compartment 434 (D13)	2/0	2/0	NA
13	Control	239'	4-kV Switchgear Compartment 435 (D11)	2/0	2/0	NA
14	Control	239'	4-kV Switchgear Compartment 432 (D14)	2/0	2/0	NA
15	Control	239'	4-kV Switchgear Compartment 433 (D12)	2/0	2/0	NA
20	Control	254'	Static Inverter Room Unit 1, Area 452	NA	4/0	NA
22	Control	254'	Cable Spreading Room Unit 1, Area 449	NA	14/0	NA
24A	Control	269'	Control Room 533	NA	23(a)/0 11(b)/0	NA
24B	Control	269'	Control Room Utility Room 529	NA	1/0	NA
24C	Control	269'	Control Room Office 531	NA	1/0	NA
24D	Control	269'	Control Room Shift Supt. 532	NA	1/0	NA
24E	Control	269'	Control Room Shop 534	NA	1/0 (Photo-Elect)	NA
24F	Control	269'	Control Room Instrument Lab 535	NA	1/0 (Photo-Elect)	NA
24G	Control	269'	Control Room Shift Supt. 532A	NA	1/0	NA

TABLE 3.3.7.9-1 (Continued)

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION				TOTAL NUMBER OF INSTRUMENTS*		
FIRE ZONE	STRUCTURE	ELEV.	AREA	HEAT (x/y)	SMOKE (x/y)	FLAME (x/y)
25	Control	289'	Auxiliary Equipment Room 542	0/112 (PGCC Floor) 0/13 (Non-PGCC Floor)	57/0 (Ceiling) 56/0 (PGCC Floor) 14/0 (Non-PGCC Floor) 32/0 (Terminal Cabinets)	NA
26	Control	289'	Remote Shutdown Panel Area 540	0/4 (Non-PGCC Floor)	3/0 (Ceiling Level) 2/0 (Non-PGCC Floor)	NA
27	Control	304'	Control Structure Fan Room 619	0/23 4/0 (inside plenum)	10/0	NA
28A	Control	332'	SGTS Access Area 625 (SGTS Room Ventilation Exhaust)	4/0 (inside plenum)	NA	NA
28B	Control	332'	SGTS Filter Compartment 624	4/0 (inside plenum)	NA	NA
28C	Control	332'	Control Room Fresh Air Intake Plenum	NA	3/0	NA
31	Unit 1 Reactor	177'	RHR Heat Exchanger & Pump Room 103 (B&D)	NA	6/0	NA
32	Unit 1 Reactor	177'	RHR Heat Exchanger & Pump Room 102 (A&C)	NA	5/0	NA
33	Unit 1 Reactor	177'	RCIC Pump Room 108	0/3	2/0	NA
34	Unit 1 Reactor	177'	HPCI Pump Room 109	0/4	3/0	NA
35	Unit 1 Reactor	177'	'A' Core Spray Pump Room 110	NA	2/0	NA

TABLE 3.3.7.11-1

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

	INSTRUMENT	MINIMUM CHANNELS OPERABLE	ACTION
1.	GROSS RADIOACTIVITY MONITORS PROVIDING AUTOMATIC TERMINATION OF RELEASE		
	a. Liquid Radwaste Effluent Line	1	100
	b. RHR Service Water System Effluent Line	1/loop	101
2.	GROSS RADIOACTIVITY MONITORS NOT PROVIDING AUTOMATIC TERMINATION OF RELEASE		
	a. Service Water System Effluent Line	1	101
3.	FLOW RATE MEASUREMENT DEVICES		
	a. Liquid Radwaste Effluent Line	1	102
	b. Discharge Line	1	102

TABLE 3.3.7.11-1 (Continued)

ACTION STATEMENTS

ACTION 100 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases may continue for up to 14 days provided that prior to initiating a release:

a. At least two independent samples are analyzed in accordance with Specification 4.11.1.1.1, and

b. At least two technically qualified members of the facility staff independently verify the release rate calculations and discharge line valving;

Otherwise, suspend release of radioactive effluents via this pathway.

ACTION 101 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue for up to 30 days provided that, at least once per 8 hours, grab samples are collected and analyzed for gross radioactivity (beta or gamma). Beta is analyzed at a limit of detection of at least 1N7 microcurie/mL. Gamma is analyzed at a limit of detection of at least 5N7 microcurie/mL.

ACTION 102 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue for up to 30 days provided the flow rate is estimated at least once per 4 hours during actual releases. Pump curves generated in situ may be used to estimate flow.

SURVEILLANCE REQUIREMENTS (Continued)

4.4.6.1.2 The reactor coolant system temperature and pressure shall be determined to be to the right of the criticality limit line of Figure 3.4.6.1-1 curves C and C' within 15 minutes prior to the withdrawal of control rods to bring the reactor to criticality and at least once per 30 minutes during system heatup.

4.4.6.1.3 The reactor vessel material surveillance specimens shall be removed and examined, to determine changes in reactor pressure vessel material properties, as required by 10 CFR Part 50, Appendix H in accordance with the schedule in Table 4.4.6.1.3-1. The results of these examinations shall be used to update the curves of Figure 3.4.6.1-1.

4.4.6.1.4 The reactor flux wire specimens shall be removed at the first refueling outage and examined to determine reactor pressure vessel fluence as a function of time and power level and used to modify Figure B 3/4 4.6-1. The results of these fluence determinations shall be used to adjust the curves of Figure 3.4.6.1-1, as required.

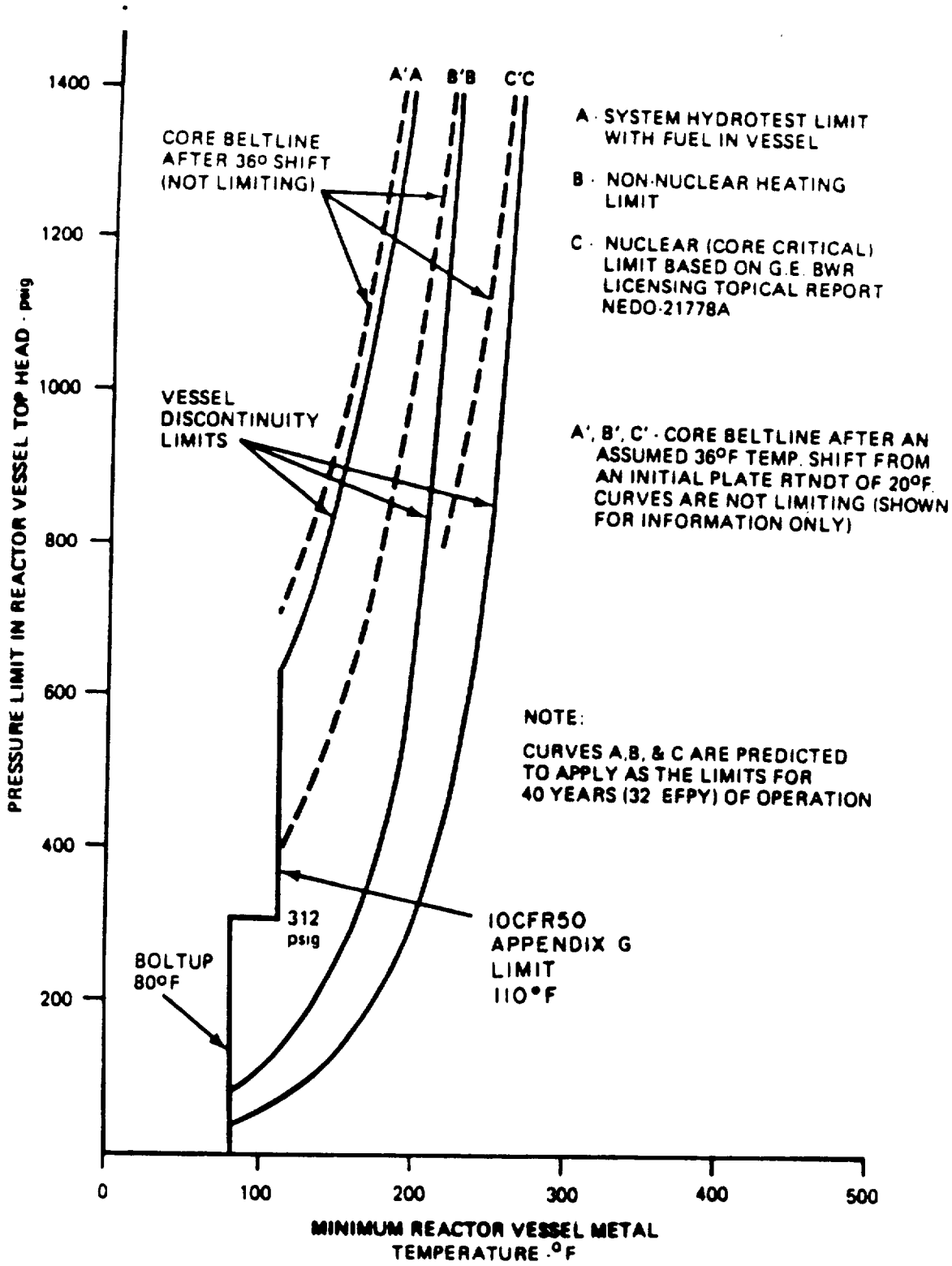
4.4.6.1.5 The reactor vessel flange and head flange temperature shall be verified to be greater than or equal to 80°F:

a. In OPERATIONAL CONDITION 4 when reactor coolant system temperature is:

   1. $\leq$ 100°F, at least once per 12 hours.

   2. $\leq$ 90°F, at least once per 30 minutes.

b. Within 30 minutes prior to and at least once per 30 minutes during tensioning of the reactor vessel head bolting studs.



MINIMUM REACTOR PRESSURE VESSEL METAL TEMPERATURE VS. REACTOR VESSEL PRESSURE

FIGURE 3.4.6.1-1

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

d. For the ADS:

1. With one of the above required ADS valves inoperable, provided the HPCI system, the CSS and the LPCI system are OPERABLE, restore the inoperable ADS valve to OPERABLE status within 14 days or be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to $\leq$ 100 psig within the next 24 hours.

2. With two or more of the above required ADS valves inoperable, be in at least HOT SHUTDOWN within 12 hours and reduce reactor steam dome pressure to $\leq$ 100 psig within the next 24 hours.

e. With a CSS and/or LPCI header ΔP instrumentation channel inoperable, restore the inoperable channel to OPERABLE status within 72 hours or determine the ECCS header ΔP locally at least once per 12 hours; otherwise, declare the associated CSS and/or LPCI, as applicable, inoperable.

f. In the event an ECCS system is actuated and injects water into the reactor coolant system, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date. The current value of the useage factor for each affected safety injection nozzle shall be provided in this Special Report whenever its value exceeds 0.70.

SURVEILLANCE REQUIREMENTS

4.5.1 The emergency core cooling systems shall be demonstrated OPERABLE by:

a. At least once per 31 days:

1. For the CSS, the LPCI system, and the HPCI system:

a) Verifying by venting at the high point vents that the system piping from the pump discharge valve to the system isolation valve is filled with water.

b) Verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct* position.

2. For the LPCI system, verifying that both LPCI system subsystem cross-tie valves (HV-51-182 A, B) are closed with power removed from the valve operators.

3. For the HPCI system, verifying that the HPCI pump flow controller is in the correct position.

4. For the CSS and LPCI system, performance of a CHANNEL FUNCTIONAL TEST of the injection header ΔP instrumentation.

b. Verifying that, when tested pursuant to Specification 4.0.5:

1. Each CSS pump in each subsystem develops a flow of at least 3175 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of $\geq$ 105 psid plus head and line losses.

2. Each LPCI pump in each subsystem develops a flow of at least 10,000 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of $\geq$ 20 psid plus head and line losses.

3. The HPCI pump develops a flow of at least 5600 gpm against a test line pressure which corresponds to a reactor vessel pressure of 1000 psig plus head and line losses when steam is being supplied to the turbine at 1000, +20, -80 psig.**

c. At least once per 18 months:

1. For the CSS, the LPCI system, and the HPCI system, performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence and verifying that each automatic valve in the flow path actuates to its correct position. Actual injection of coolant into the reactor vessel may be excluded from this test.

---

*Except that an automatic valve capable of automatic return to its ECCS position when an ECCS signal is present may be in position for another mode of operation.

**The provisions of Specification 4.0.4 are not applicable, provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 200 psig within the following 72 hours.

SURVEILLANCE REQUIREMENTS (Continued)

2. For the HPCI system, verifying that:

   a) The system develops a flow of at least 5600 gpm against a test line pressure corresponding to a reactor vessel pressure of ≥ 200 psig plus head and line losses, when steam is being supplied to the turbine at 200 + 15, - 0 psig.**

   b) The suction is automatically transferred from the condensate storage tank to the suppression chamber on a condensate storage tank water level - low signal and on a suppression chamber - water level high signal.

3. Performing a CHANNEL CALIBRATION of the CSS, LPCI, and HPCI system discharge line "keep filled" alarm instrumentation.

4. Performing a CHANNEL CALIBRATION of the CSS header ΔP instrumentation and verifying the setpoint to be ≤ the allowable value of 4.4 psid.

5. Performing a CHANNEL CALIBRATION of the LPCI header ΔP instrumentation and verifying the setpoint to be ≤ the allowable value of 3.0 psid.

d. For the ADS:

1. At least once per 31 days, performing a CHANNEL FUNCTIONAL TEST of the accumulator backup compressed gas system low pressure alarm system.

2. At least once per 18 months:

   a) Performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence, but excluding actual valve actuation.

   b) Manually opening each ADS valve when the reactor steam dome pressure is greater than or equal to 100 psig** and observing that either:

      1) The control valve or bypass valve position responds accordingly, or

      2) There is a corresponding change in the measured steam flow.

   c) Performing a CHANNEL CALIBRATION of the accumulator backup compressed gas system low pressure alarm system and verifying an alarm setpoint of 90 ± 2 psig on decreasing pressure.

**The provisions of Specification 4.0.4 are not applicable, provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If HPCI or ADS OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 200 psig or 100 psig, respectively within the following 72 hours.

3/4 5.2 ECCS - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.5.2 At least two of the following shall be OPERABLE:

a. Core spray system (CSS) subsystems with a subsystem comprised of:

1. Two OPERABLE CSS pumps, and

2. An OPERABLE flow path capable of taking suction from at least one of the following water sources and transferring the water through the spray sparger to the reactor vessel:

a) From the suppression chamber, or

b) When the suppression chamber water level is less than the limit or is drained, from the condensate storage tank containing at least 135,000 available gallons of water, equivalent to a level of 29 feet.

b. Low pressure coolant injection (LPCI) system subsystems with a subsystem comprised of:

1. One OPERABLE LPCI pump, and

2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

APPLICABILITY: OPERATIONAL CONDITIONS 4 and 5*.

ACTION:

a. With one of the above required subsystems inoperable, restore at least two subsystems to OPERABLE status within 4 hours or suspend all operations with a potential for draining the reactor vessel.

b. With both of the above required subsystems inoperable, suspend CORE ALTERATIONS and all operations with a potential for draining the reactor vessel. Restore at least one subsystem to OPERABLE status within 4 hours or establish SECONDARY CONTAINMENT INTEGRITY within the next 8 hours.

---

*The ECCS is not required to be OPERABLE provided that the reactor vessel head is removed, the cavity is flooded, the spent fuel pool gates are removed, and water level is maintained within the limits of Specifications 3.9.8 and 3.9.9.

DRYWELL AND SUPPRESSION CHAMBER INTERNAL PRESSURE

LIMITING CONDITION FOR OPERATION

3.6.1.6 Drywell and suppression chamber internal pressure shall be maintained between -1.0 and +2.0 psig.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

With the drywell and/or suppression chamber internal pressure outside of the specified limits, restore the internal pressure to within the limit within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.6 The drywell and suppression chamber internal pressure shall be determined to be within the limits at least once per 12 hours.

DRYWELL AVERAGE AIR TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.6.1.7 Drywell average air temperature shall not exceed 135°F.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

With the drywell average air temperature greater than 135°F, reduce the average air temperature to within the limit within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.7 The drywell average air temperature shall be the volumetric average of the temperatures at the following locations and shall be determined to be within the limit at least once per 24 hours:

	Approximate Elevation	Number of Installed Sensors*
a.	330'	3
b.	320'	3
c.	260'	3
d.	248'	6

*At least one reading from each elevation is required for a volumetric average calculation.

DRYWELL AND SUPPRESSION CHAMBER PURGE SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.1.8 The drywell and suppression chamber purge system may be in operation for up to 90 hours each 365 days with the supply and exhaust isolation valves in one supply line and one exhaust line open for inerting, deinerting, or pressure control.*

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With a drywell and/or suppression chamber purge supply and/or exhaust isolation valve open, except as permitted above, close the valve(s) within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.8 Before being opened, the drywell and suppression chamber purge supply and exhaust butterfly isolation valves shall be verified not to have been open for more than 90 hours in the previous 365 days.*

*Valves open for pressure control are not subject to the 90 hour per 365 day limit provided the 1-inch/2-inch bypass line is being utilized.

3/4.6.2 DEPRESSURIZATION SYSTEMS

SUPPRESSION CHAMBER

LIMITING CONDITION FOR OPERATION

3.6.2.1 The suppression chamber shall be OPERABLE with:

a. The pool water:

1. Volume* between 122,120 ft^3 and 134,600 ft^3, equivalent to a level between 22' 0" and 24' 3", and a

2. Maximum average temperature of 95°F except that the maximum average temperature may be permitted to increase to:

a) 105°F during testing which adds heat to the suppression chamber.

b) 110°F with THERMAL POWER less than or equal to 1% of RATED THERMAL POWER.

c) 120°F with the main steam line isolation valves closed following a scram.

b. Drywell-to-suppression chamber bypass leakage less than or equal to 10% of the acceptable $A/\sqrt{K}$ design value of 0.0500 ft^2.

c. At least eight suppression pool water temperature instrumentation indicators, one in each of the eight locations.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With the suppression chamber water level outside the above limits, restore the water level to within the limits within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With the suppression chamber average water temperature greater than 95°F, restore the average temperature to less than or equal to 95°F within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours, except, as permitted above:

1. With the suppression chamber average water temperature greater than 105°F during testing which adds heat to the suppression chamber, stop all testing which adds heat to the suppression chamber and restore the average temperature to less than 95°F within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With the suppression chamber average water temperature greater than:

a) 95°F for more than 24 hours and THERMAL POWER greater than 1% of RATED THERMAL POWER, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b) 110°F, place the reactor mode switch in the Shutdown position and operate at least one residual heat removal loop in the suppression pool cooling mode.

*Includes the volume inside the pedestal.

3/4.6.3 PRIMARY CONTAINMENT ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.3 The primary containment isolation valves and the instrumentation line excess flow check valves shown in Table 3.6.3-1 shall be OPERABLE with isolation times less than or equal to those shown in Table 3.6.3-1.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one or more of the primary containment isolation valves shown in Table 3.6.3-1 inoperable, maintain at least one isolation valve OPERABLE in each affected penetration that is open and within 4 hours either:

   1. Restore the inoperable valve(s) to OPERABLE status, or
   2. Isolate each affected penetration by use of at least one deactivated automatic valve secured in the isolated position,* or
   3. Isolate each affected penetration by use of at least one closed manual valve or blind flange.*
   4. The provisions of Specification 3.0.4 are not applicable provided that within 4 hours the affected penetration is isolated in accordance with ACTION a.2. or a.3. above, and provided that the associated system, if applicable, is declared inoperable and the appropriate ACTION statements for that system are performed.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one or more of the instrumentation line excess flow check valves shown in Table 3.6.3-1 inoperable, operation may continue and the provisions of Specifications 3.0.3 and 3.0.4 are not applicable provided that within 4 hours either:

   1. The inoperable valve is returned to OPERABLE status, or
   2. The instrument line is isolated and the associated instrument is declared inoperable.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

---

*Isolation valves closed to satisfy these requirements may be reopened on an intermittent basis under administrative control.

SURVEILLANCE REQUIREMENTS

4.6.3.1 Each primary containment isolation valve shown in Table 3.6.3-1 shall be demonstrated OPERABLE prior to returning the valve to service after maintenance, repair or replacement work is performed on the valve or its associated actuator, control or power circuit by cycling the valve through at least one complete cycle of full travel and verifying the specified isolation time.

4.6.3.2 Each primary containment automatic isolation valve shown in Table 3.6.3-1 shall be demonstrated OPERABLE during COLD SHUTDOWN or REFUELING at least once per 18 months by verifying that on a containment isolation test signal each automatic isolation valve actuates to its isolation position.

4.6.3.3 The isolation time of each primary containment power operated or automatic valve shown in Table 3.6.3-1 shall be determined to be within its limit when tested pursuant to Specification 4.0.5.

4.6.3.4 Each instrumentation line excess flow check valve shown in Table 3.6.3-1 shall be demonstrated OPERABLE at least once per 18 months by verifying that the valve checks flow.

4.6.3.5 Each traversing in-core probe system explosive isolation valve shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying the continuity of the explosive charge.

b. At least once per 18 months by removing the explosive squib from the explosive valve, such that each explosive squib in each explosive valve will be tested at least once per 90 months, and initiating the explosive squib. The replacement charge for the exploded squib shall be from the same manufactured batch as the one fired or from another batch which has been certified by having at least one of that batch successfully fired. No squib shall remain in use beyond the expiration of its shelf-life and/or operating life, as applicable.

TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX. ISOL. TIME. IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
028B	DRYWELL H2/02 SAMPLE	SV57-133		5	B,H,R,S	11	57
			SV57-143	5	B,H,R,S	11	
			SV57-195	5	B,H,R,S	11	
030B-1	DRYWELL PRESSURE INSTRUMENTATION		HV42-147A	45		10	42
035B	TIP PURGE	59-1056(CK) (DOUBLE "O" RING)		NA			59
			HV59-131	7	B,H,S	16	
035C-G	TIP DRIVES	XV59-141A-E (DOUBLE "O" RING)		NA	B,H	11,16,21	59
			XV59-140A-E	NA		11,16	
037A-D	CRD INSERT LINES	BALL CHECK		NA		12	47
			HCU	NA		12	
038A-D	CRD WITHDRAW LINES SDV VENTS & DRAINS		HCU	NA		12	47
			XV47-1F010	25		30	
			XV47-1F180	30		30	
			XV47-1F011	25		30	
			XV47-1F181	30		30	
039A(B)	DRYWELL SPRAY	HV51-1F021A(B)		160		4,11	51
			HV51-1F016A(B)	160		11	
040E	DRYWELL PRESSURE INSTRUMENTATION		HV42-147D	45		10	42
040F-2	CONTAINMENT INSTRUMENT GAS -SUCTION	HV59-101		45	C,H,S	5	59
			HV59-102	7	C,H,S		

TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX. ISOL. TIME. IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
040G-1	ILRT DATA ACQUISITION	60-1057		NA		11	60
			60-1058	NA		11	
040G-2	ILRT DATA ACQUISITION	60-1071		NA		11	60
			60-1070	NA		11	
040H-1	CONTAINMENT INSTRUMENT GAS SUPPLY - HEADER 'A'	59-1005A(CK)		NA			59
			HV59-129A	7	C,H,S		
042	STANDBY LIQUID CONTROL	48-1F007(CK) (X-116)		NA			48
			HV48-1F006A	60		29	
043B	MAIN STEAM SAMPLE	HV41-1F084		10	B,D		41
			HV41-1F085	10	B,D		
044	RWCU ALTERNATE RETURN	41-1017		NA		5,31	41
			41-1016(X-9A, X-9B)	NA			
			PSV41-112	NA			
045A(B,C,D)	LPCI INJECTION 'A'(B,C,D)	HV51-1F041A*(B,C*, D*)(CK)		NA		9,22	51
		HV51-142A*(B,C*, D*)		7		9,22	
			HV51-1F017A* (B,C*,D*)	38			
050A-1	DRYWELL PRESSURE INSTRUMENTATION		HV42-147B	45		10	42
053	DRYWELL CHILLED WATER SUPPLY - LOOP 'A'	HV87-128*		60	C,H	11	87
			HV87-120A*	60	C,H	11	
			HV87-125A*	60	C,H	11	

TABLE 3.6.3-1
PRIMARY CONTAINMENT ISOLATION VALVES
NOTATION

NOTES

1. Instrumentation line isolation provisions consist of an orifice and excess flow-check valve or remote manual isolation valve. The excess flow-check valve is subjected to operability testing, but no Type C test is performed or required. The line does not isolate during a LOCA and can leak only if the line or instrument should rupture. Leaktightness of the line is verified during the integrated leak rate test (Type A test).

2. Penetration is sealed by a blind flange or door with double O-ring seals. These seals are leakage rate tested by pressurizing between the O-rings.

3. Inboard butterfly valve tested in the reverse direction.

4. Inboard gate valve tested in the reverse direction.

5. Inboard globe valve tested in the reverse direction.

6. The MSIVs and this penetration are tested by pressurizing between the valves. Testing of the inboard valve in the reverse direction tends to unseat the valve and is therefore conservative. The valves are Type C tested at a test pressure of 22 psig.

7. Gate valve tested in the reverse direction.

8. Electrical penetrations are tested by pressurizing between the seals.

9. The isolation provisions for this penetration consist of two isolation valves and a closed system outside containment. Because a water seal is maintained in these lines by the safeguard piping fill system, the inboard valve may be tested with water. The outboard valve will be pneumatically tested.

10. The valve does not receive an isolation signal but remains open to measure containment conditions post-LOCA. Leaktightness of the penetration is verified during the Type A test. Type C test is not required.

11. All isolation barriers are located outside containment.

12. Leakage monitoring of the control rod drive insert and withdraw line is provided by Type A leakage rate test. Type C test is not required.

13. The motor operators on HV-13-109 and HV-13-110 are not connected to any power supply.

14. Valve is provided with a separate testable seal assembly, with double concentric O-ring seals installed between the pipe flange and valve flange facing primary containment. Leakage through these seals is included within the Type C leakage rate for this penetration.

TABLE 3.6.3-1
PRIMARY CONTAINMENT ISOLATION VALVES
NOTATION

NOTES (Continued)

15. Check valve used instead of flow orifice.

16. Penetration is sealed by a flange with double O-ring seals. These seals are leakage rate tested by pressurizing between the O-rings. Both the TIP Purge Supply (Penetration 35B) and the TIP Drive Tubes (Penetration 35C-G) are welded to their respective flanges. Leakage through these seals is included in the Type C leakage rate total for this penetration. The ball valves (XV-141A-E) are Type C tested. It is not practicable to leak test the shear valves (XV-140A-E) because squib firing is required for closure. Shear valves (XV-140A-G) are normally open.

17. Instrument line isolation provisions consist of an excess flow check valve. Because the instrument line is connected to a closed cooling water system inside containment, no flow orifice is provided. The excess flow check valves are subject to operability testing, but no Type C test is performed nor required. The line does not isolate during a LOCA and can leak only if the line or instrument should rupture. Leaktightness of the line is verified during the integrated leak rate test (Type A test).

18. In addition to double "O" ring seals, this penetration is tested by pressurizing volume between doors per Specification 4.6.1.3.

19. The RHR system safety pressure relief valves will be exempted from the initial LLRT. The relief valves in these lines will be exposed to containment pressure during the initial ILRT and all subsequent ILRTs. In addition, modifications will be performed at the first refueling to facilitate local testing or removal and bench testing of the relief valves during subsequent LLRTs. Those relief valves which are flanged to facilitate removal will be equipped with double O-ring seal assemblies on the flange closest to primary containment by the end of the first refueling outage. These seals will be leak rate tested by pressurizing between the O-rings, and the results added into the Type C total for this penetration.

20. See Specification 3.3.2, Table 3.3.2-1, for a description of the PCRVICS isolation signal(s) that initiate closure of each automatic isolation valve. In addition, the following non-PCRVICS isolation signals also initiate closure of selected valves:

    EA Main steam line high pressure, high steam line leakage flow, low MSIV-LCS dilution air flow

    LFHP With HPCI pumps running, opens on low flow in associated pipe, closes when flow is above setpoint

    LFRC With RCIC pump running, opens on low flow in associated pipe, closes when flow is above setpoint

    LFCH With CSS pump running, opens on low flow in associated pipe, closes when flow is above setpoint

    LFCC Steam supply valve fully closed or RCIC turbine stop valve fully closed

All power operated isolation valves may be opened or closed remote manually.

3/4.6.5 SECONDARY CONTAINMENT

REFUELING AREA SECONDARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.5.1.2 REFUELING AREA SECONDARY CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: OPERATIONAL CONDITION *.

ACTION:

Without REFUELING AREA SECONDARY CONTAINMENT INTEGRITY, suspend handling of irradiated fuel in the secondary containment, CORE ALTERATIONS and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.5.1.2 REFUELING AREA SECONDARY CONTAINMENT INTEGRITY shall be demonstrated by:

a. Verifying at least once per 24 hours that the pressure within the refueling area secondary containment is greater than or equal to 0.25 inch of vacuum water gauge.

b. Verifying at least once per 31 days that:

   1. All refueling area secondary containment equipment hatches and blowout panels are closed and sealed.

   2. At least one door in each access to the refueling area secondary containment is closed.

   3. All refueling area secondary containment penetrations not capable of being closed by OPERABLE secondary containment automatic isolation dampers/valves and required to be closed during accident conditions are closed by valves, blind flanges, slide gate dampers or deactivated automatic dampers/valves secured in position.

c. At least once per 18 months:

   Operating one standby gas treatment subsystem for one hour and maintaining greater than or equal to 0.25 inch of vacuum water gauge in the refueling area secondary containment at a flow rate not exceeding 764 cfm.

*Required when (1) irradiated fuel is being handled in the refueling area secondary containment, or (2) during CORE ALTERATIONS, or (3) during operations with a potential for draining the reactor vessel, with the vessel head removed and fuel in the vessel.

REACTOR ENCLOSURE SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.5.2.1 The reactor enclosure secondary containment ventilation system automatic isolation valves shown in Table 3.6.5.2.1-1 shall be OPERABLE with isolation times less than or equal to the times shown in Table 3.6.5.2.1-1.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

With one or more of the reactor secondary containment ventilation system automatic isolation valves shown in Table 3.6.5.2.1-1 inoperable, maintain at least one isolation valve OPERABLE in each affected penetration that is open and within 8 hours either:

a. Restore the inoperable valves to OPERABLE status, or

b. Isolate each affected penetration by use of at least one deactivated valve secured in the isolation position, or

c. Isolate each affected penetration by use of at least one closed manual valve, blind flange or slide gate damper.

Otherwise, in OPERATIONAL CONDITION 1, 2 or 3, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.5.2.1 Each reactor enclosure secondary containment ventilation system automatic isolation valve shown in Table 3.6.5.2.1-1 shall be demonstrated OPERABLE:

a. Prior to returning the valve to service after maintenance, repair or replacement work is performed on the valve or its associated actuator, control or power circuit by cycling the valve through at least one complete cycle of full travel and verifying the specified isolation time.

b. At least once per 18 months by verifying that on a containment isolation test signal each isolation valve actuates to its isolation position.

c. By verifying the isolation time to be within its limit at least once per 92 days.

STANDBY GAS TREATMENT SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.5.3 Two independent standby gas treatment subsystems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, and *.

ACTION:

a. With one standby gas treatment subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days, or:

   1. In OPERATIONAL CONDITION 1, 2, or 3, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

   2. In Operational Condition *, suspend handling of irradiated fuel in the secondary containment, CORE ALTERATIONS and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

b. With both standby gas treatment subsystems inoperable in Operational Condition *, suspend handling of irradiated fuel in the secondary containment, CORE ALTERATIONS or operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3. are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.5.3 Each standby gas treatment subsystem shall be demonstrated OPERABLE:

a. At least once per 31 days by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the subsystem operates with the heaters OPERABLE.

*Required when (1) irradiated fuel is being handled in the refueling area secondary containment, or (2) during CORE ALTERATIONS, or (3) during operations with a potential for draining the reactor vessel with the vessel head removed and fuel in the vessel.

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.3 The reactor core isolation cooling (RCIC) system shall be OPERABLE with an OPERABLE flow path capable of automatically taking suction from the suppression pool and transferring the water to the reactor pressure vessel.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3 with reactor steam dome pressure greater than 150 psig.

ACTION:

a. With the RCIC system inoperable, operation may continue provided the HPCI system is OPERABLE; restore the RCIC system to OPERABLE status within 14 days. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to less than or equal to 150 psig within the following 24 hours.

b. In the event the RCIC system is actuated and injects water into the reactor coolant system, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date.

SURVEILLANCE REQUIREMENTS

4.7.3 The RCIC system shall be demonstrated OPERABLE:

a. At least once per 31 days by:

1. Verifying by venting at the high point vents that the system piping from the pump discharge valve to the system isolation valve is filled with water.

2. Verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

3. Verifying that the pump flow controller is in the correct position.

b. At least once per 92 days by verifying that the RCIC pump develops a flow of greater than or equal to 600 gpm in the test flow path with a system head corresponding to reactor vessel operating pressure when steam is being supplied to the turbine at 1000 + 20, - 80 psig.*

*The provisions of Specification 4.0.4 are not applicable, provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam pressure to less than 150 psig within the following 72 hours.

SURVEILLANCE REQUIREMENTS (Continued)

c. At least once per 18 months by:

1. Performing a system functional test which includes simulated automatic actuation and restart and verifying that each automatic valve in the flow path actuates to its correct position. Actual injection of coolant into the reactor vessel may be excluded.

2. Verifying that the system will develop a flow of greater than or equal to 600 gpm in the test flow path when steam is supplied to the turbine at a pressure of 150 + 15, - 0 psig.*

3. Verifying that the suction for the RCIC system is automatically transferred from the condensate storage tank to the suppression pool on a condensate storage tank water level-low signal.

4. Performing a CHANNEL CALIBRATION of the RCIC system discharge line "keep filled" level alarm instrumentation.

*The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the tests. If OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam pressure to less than 150 psig within the following 72 hours.

SURVEILLANCE REQUIREMENTS (Continued)

4.7.6.1.3 The diesel-driven fire pump starting 24-volt battery bank and charger shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that:

1. The electrolyte level of each cell is above the plates,

2. The pilot cell specific gravity, corrected to 77°F and full electrolyte level, is greater than or equal to 1.260, and

3 The overall battery voltage is greater than or equal to 24 volts.

b. At least once per 92 days by verifying that the specific gravity is appropriate for continued service of the battery.

c. At least once per 18 months by verifying that:

1. The batteries, cell plates, and battery racks show no visual indication of physical damage or abnormal deterioration, and

2. Battery-to-battery and terminal connections are clean, tight, free of corrosion, and coated with anticorrosion material.

SPRAY AND/OR SPRINKLER SYSTEMS

LIMITING CONDITION FOR OPERATION

3.7.6.2 The following spray and sprinkler systems shall be OPERABLE:

Fire Zone	Description
	Reactor Enclosure Hatchway Water Curtains:
	1. EL 253'
	2. EL 283'
	3. EL 313'
	Fire Area Separation Water Curtains:
48A	1. Area 602, EL 313'
45A	2. Area 402, EL 253'
44	3. Area 304, EL 217' (2 curtains)
22	Cable Spreading Room, Room 450, EL 254',
27	Control Structure Fan Room, EL 304'
27	CREFAS System Filters, EL 304'
28B	SGTS Filters, Compartment 624 and SGTS Access Area 625, EL 332'
33	RCIC Pump Room, Room 108, EL 177'
34	HPCI Pump Room, Room 109, EL 177'
41	RECW Area, EL 201'
42A	Safeguard System Access Area 200, EL 201'
44	Safeguard System Access Area 304, EL 217' (Partial) (2 systems)
45A	CRD Hydraulic Equipment Area 402, Reactor Enclosure, EL 253' (Partial)
45B	Neutron Monitoring System Area 406, El 253' (Partial)
47A	General Equipment Area 500 and Corridor 506, Reactor Enclosure, EL 283' (Partial)
51A & B	Reactor Enclosure Recirculation System Filters, EL 331'
79,80,81,82	Diesel Generator cells (4 Cells)

APPLICABILITY: Whenever equipment protected by the spray and/or sprinkler systems is required to be OPERABLE.

ACTION:

a. With one or more of the above required spray and/or sprinkler systems inoperable, within 1 hour establish a continuous fire watch with backup fire suppression equipment for those areas in which redundant systems or components could be damaged; for other areas, establish an hourly fire watch patrol.

b. The provisions of Specification 3.0.3 are not applicable.

3/4.6.1 PRIMARY CONTAINMENT

3/4.6.1.1 PRIMARY CONTAINMENT INTEGRITY

PRIMARY CONTAINMENT INTEGRITY ensures that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the safety analyses. This restriction, in conjunction with the leakage rate limitation, will limit the SITE BOUNDARY radiation doses to within the limits of 10 CFR Part 100 during accident conditions.

3/4.6.1.2 PRIMARY CONTAINMENT LEAKAGE

The limitations on primary containment leakage rates ensure that the total containment leakage volume will not exceed the value assumed in the safety analyses at the peak accident pressure of 44.02 psig, P_a. As an added conservatism, the measured overall integrated leakage rate is further limited to less than or equal to 0.75 L_a during performance of the periodic tests to account for possible degradation of the containment leakage barriers between leakage tests.

Operating experience with the main steam line isolation valves has indicated that degradation has occasionally occurred in the leak tightness of the valves; therefore the special requirement for testing these valves.

The surveillance testing for measuring leakage rates is consistent with the requirements of Appendix J of 10 CFR Part 50 with the exception of exemptions granted for leak testing of the main steam isolation valves, the airlock, TIP shear valves and RHR relief valves.

3/4.6.1.3 PRIMARY CONTAINMENT AIR LOCKS

The limitations on closure and leak rate for the primary containment air locks are required to meet the restrictions on PRIMARY CONTAINMENT INTEGRITY and the primary containment leakage rate given in Specifications 3.6.1.1 and 3.6.1.2. The specification makes allowances for the fact that there may be long periods of time when the air locks will be in a closed and secured position during reactor operation. Only one closed door in each air lock is required to maintain the integrity of the containment.

3/4.6.1.4 MSIV LEAKAGE CONTROL SYSTEM

Calculated doses resulting from the maximum leakage allowance for the main steamline isolation valves in the postulated LOCA situations would be a small fraction of the 10 CFR Part 100 guidelines, provided the main steam line system from the isolation valves up to and including the turbine condenser remains intact. Operating experience has indicated that degradation has occasionally occurred in the leak tightness of the MSIVs such that the specified leakage requirements have not always been maintained continuously. The requirement for the leakage control system will reduce the untreated leakage from the MSIVs when isolation of the primary system and containment is required.

3/4.6.1.5 PRIMARY CONTAINMENT STRUCTURAL INTEGRITY

This limitation ensures that the structural integrity of the containment will be maintained comparable to the original design standards for the life of the unit. Structural integrity is required to ensure that the containment will withstand the maximum pressure of 44.02 psig in the event of a LOCA. A visual inspection in conjunction with Type A leakage tests is sufficient to demonstrate this capability.

3/4.6.1.6 DRYWELL AND SUPPRESSION CHAMBER INTERNAL PRESSURE

The limitations on drywell and suppression chamber internal pressure ensure that the containment peak pressure of 44.02 psig does not exceed the design pressure of 55 psig during LOCA conditions or that the external pressure differential does not exceed the design maximum external pressure differential of 5.0 psid. The limit of - 1.0 to + 2.0 psig for initial containment pressure will limit the total pressure to 44.02 psig which is less than the design pressure and is consistent with the safety analysis.

3/4.6.1.7 DRYWELL AVERAGE AIR TEMPERATURE

The limitation on drywell average air temperature ensures that the containment peak air temperature does not exceed the design temperature of 340°F during steam line break conditions and is consistent with the safety analysis.

3/4.6.1.8 DRYWELL AND SUPPRESSION CHAMBER PURGE SYSTEM

The drywell and suppression chamber purge supply and exhaust isolation valves are required to be closed during plant operation except as required for inerting, deinerting and pressure control. The 90 hours per 365 day limit on purge valve operation is imposed to protect the integrity of the SGTS filters. Analysis indicates that should a LOCA occur while this pathway is being utilized, the associated pressure surge through the (18 or 24") purge lines will adversely affect the integrity of SGTS. This limit is not imposed, however, on the subject valves when pressure control is being performed through the 2-inch bypass line, since a pressure surge through this line does not threaten the OPERABILITY of SGTS.

SAFETY LIMIT VIOLATION (Continued)

b. A Safety Limit Violation Report shall be prepared. The report shall be reviewed by the NRB. This report shall describe (1) applicable circumstances preceding the violation, (2) effects of the violation upon unit components, systems, or structures, and (3) corrective action taken to prevent recurrence.

c. The Safety Limit Violation Report shall be submitted to the Commission, the NRB, Plant Manager, and the Vice President, Limerick Generating Station, within 14 days of the violation.

d. Critical operation of the unit shall not be resumed until authorized by the Commission.

6.8 PROCEDURES AND PROGRAMS

6.8.1 Written procedures shall be established, implemented, and maintained covering the activities referenced below:

a. The applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978.

b. The applicable procedures required to implement the requirements of NUREG-0737 and Supplement 1 to NUREG-0737.

c. Refueling operations.

d. Surveillance and test activities of safety-related equipment.

e. Security Plan implementation.

f. Emergency Plan implementation.

g. Fire Protection Program implementation.

h. PROCESS CONTROL PROGRAM implementation.

i. OFFSITE DOSE CALCULATION MANUAL implementation.

j. Quality Assurance Program for effluent and environmental monitoring, using the guidance of Regulatory Guide 4.15, February 1979.

6.8.2 Each procedure of Specification 6.8.1, and changes thereto, shall be reviewed in accordance with Specification 6.5.1.6 and shall be approved by the Plant Manager or designee prior to implementation and reviewed periodically as set forth in administrative procedures.

6.8.3 Temporary changes to procedures of Specification 6.8.1 may be made provided:

a. The intent of the original procedure is not altered;

b. The change is approved by two members of the unit management staff, at least one of whom holds a Senior Operator license on the unit affected; and

c. The change is documented, reviewed by the PORC, and approved by the Plant Manager or designee within 14 days of implementation.

OCT 3 1 1988

PROCEDURES AND PROGRAMS (Continued)

6.8.4 The following programs shall be established, implemented, and maintained:

a. Primary Coolant Sources Outside Containment

A program to reduce leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. The systems include the core spray, high pressure coolant injection, reactor core isolation cooling, residual heat removal, post-accident sampling system, safeguard piping fill system, control rod drive scram discharge system, and containment air monitor systems. The program shall include the following:

1. Preventive maintenance and periodic visual inspection requirements, and

2. Integrated leak test requirements for each system at refueling cycle intervals or less.

b. In-Plant Radiation Monitoring

A program which will ensure the capability to accurately determine the airborne iodine concentration in vital areas under accident conditions. This program shall include the following:

1. Training of personnel,

2. Procedures for monitoring, and

3. Provisions for maintenance of sampling and analysis equipment.

c. Post-accident Sampling

A program which will ensure the capability to obtain and analyze reactor coolant, radioactive iodines and particulates in plant gaseous effluents, and containment atmosphere samples under accident conditions. The program shall include the following:

1. Training of personnel,

2. Procedures for sampling and analysis, and

3. Provisions for maintenance of sampling and analysis equipment.

6.9 REPORTING REQUIREMENTS

ROUTINE REPORTS

6.9.1 In addition to the applicable reporting requirements of Title 10, Code of Federal Regulations, the following reports shall be submitted to the Regional Administrator of the Regional Office of the NRC unless otherwise noted.

STARTUP REPORT

6.9.1.1 A summary report of plant startup and power escalation testing shall be submitted following (1) receipt of an Operating License, (2) amendment to the license involving a planned increase in power level, (3) installation of fuel that has a different design or has been manufactured by a different fuel supplier, and (4) modifications that may have significantly altered the nuclear, thermal, or hydraulic performance of the unit.

6.9.1.2 The startup report shall address each of the tests identified in Subsection 14.2.12 of the Final Safety Analysis Report and shall include a description of the measured values of the operating conditions or characteristics obtained during the test program and a comparison of these values with design predictions and specifications. Any corrective actions that were required to obtain satisfactory operation shall also be described. Any additional specific details required in license conditions based on other commitments shall be included in this report.

6.9.1.3 Startup reports shall be submitted within (1) 90 days following completion of the startup test program, (2) 90 days following resumption or commencement of commercial power operation, or (3) 9 months following initial criticality, whichever is earliest. If the startup report does not cover all three events (i.e., initial criticality, completion of startup test program, and resumption or commencement of commercial operation) supplementary reports shall be submitted at least every 3 months until all three events have been completed.

ANNUAL REPORTS*

6.9.1.4 Annual reports covering the activities of the unit as described below for the previous calendar year shall be submitted prior to March 1 of each year. The initial report shall be submitted prior to March 1 of the year following initial criticality.

6.9.1.5 Reports required on an annual basis shall include:

a. A tabulation on an annual basis of the number of station, utility, and other personnel (including contractors) receiving exposures greater than 100 mrem/yr and their associated man-rem exposure according to work and job functions** (e.g., reactor operations and surveillance, inservice inspection, routine maintenance, special maintenance [describe maintenance], waste processing, and refueling). The dose assignments to various duty functions may be estimated based on pocket

*A single submittal may be made for a multiple unit station.
**This tabulation supplements the requirements of §20.407 of 10 CFR Part 20.

ANNUAL REPORTS (Continued)

dosimeter, thermoluminescent dosimeter (TLD), or film badge measurements. Small exposures totalling less than 20% of the individual total dose need not be accounted for. In the aggregate, at least 80% of the total whole-body dose received from external sources should be assigned to specific major work functions;

b. Documentation of all challenges to safety/relief valves; and

c. Any other unit unique reports required on an annual basis.

d. The results of specific activity analysis in which the primary coolant exceeded the limits of Specification 3.4.5. The following information shall be included: (1) Reactor power history starting 48 hours prior to the first sample in which the limit was exceeded; (2) Results of the last isotopic analysis for radioiodine performed prior to exceeding the limit, results of analysis while limit was exceeded and results of one analysis after the radioiodine activity was reduced to less than limit. Each result should include date and time of sampling and the radioiodine concentrations; (3) Cleanup system flow history starting 48 hours prior to the first sample in which the limit was exceeded; (4) Graph of the I-131 concentration and one other radioiodine isotope concentration in microcuries per gram as a function of time for the duration of the specific activity above the steady-state level; and (5) The time duration when the specific activity of the primary coolant exceeded the radioiodine limit.

MONTHLY OPERATING REPORTS

6.9.1.6 Routine reports of operating statistics and shutdown experience, including documentation of all challenges to the the main steam system safety/relief valves, shall be submitted on a monthly basis to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555, with a copy to the Regional Administrator of the Regional Office of the NRC no later than the 15th of each month following the calendar month covered by the report.

ANNUAL RADIOLOGICAL ENVIRONMENTAL OPERATING REPORT*

6.9.1.7 Routine Annual Radiological Environmental Operating Reports covering the operation of the unit during the previous calendar year shall be submitted prior to May 1 of each year. The initial report shall be submitted prior to May 1 of the year following initial criticality.

The Annual Radiological Environmental Operating Reports shall include summaries, interpretations, and an analysis of trends of the results of the radiological

*A single submittal may be made for a multiple unit station.

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

SUPPORTING AMENDMENT NO. 29 TO FACILITY OPERATING LICENSE NO. NPF-39

PHILADELPHIA ELECTRIC COMPANY

LIMERICK GENERATING STATION, UNIT 1

DOCKET NO. 50-352

1.0 INTRODUCTION

By letter dated February 14, 1986, Philadelphia Electric Company (the licensee) requested an amendment to Facility Operating License No. NPF-39 for the Limerick Generating Station, Unit 1. The proposed amendment would make administrative changes to the Technical Specifications (TSs) to achieve consistency, remove outdated material, make minor text changes and correct errors.

2.0 EVALUATION

The proposed changes to the TSs related to 28 items. Because of the diversity of the changes, each item identified in the application is discussed and evaluated separately.

Item 1, Page 3/4 7-22

Section 3.7.6.2, page 3/4 7-22, specifies the fire protection spray and sprinkler systems that shall be operable. After two of the five zones (zones 41 and 42A), there is an asterisk to a note at the bottom of the page. The note states that the two zones were not required to be operable until prior to exceeding 5% of rated thermal power. The note is no longer applicable, since Unit 1 received a full power license on August 8, 1985. The proposed change is to delete the asterisk and note. This is a purely administrative change to delete something that is no longer valid and has no safety significance.

Item 2, Page 6-14

Section 6.8.4 of the Administrative Controls Section of the TSs (page 6-14) specifies certain programs that shall be established, implemented and maintained. Subsection C, which describes the post-accident sampling program, has an asterisk referring to a note at the bottom of the page which states that the program is not required prior to exceeding 5% of rated thermal power. The proposed change is to delete the asterisk and note, since the note was only applicable when Unit 1 had a low power license. This is a purely administrative change that has no safety significance.

Item 3, Page 3/4 3-85

Table 3.3.7.5-1 (page 3/4 3-85) of the TSs lists the accident monitoring instrumentation that is required to be operable. Under applicable operational conditions, four of the instruments have a pound sign (#) in the column referring to a note at the bottom of the page. The note states that these four instruments were not required to be operable until initial criticality. Since Unit 1 has operated for over four years, the note is no longer valid. The proposed changes are to delete the references to the note and the note itself. This is a purely administrative change with no safety significance.

Item 4, Page 3/4 3-21 and Item 5, Page 3/4 3-22

Table 3.3.2-2 (pages 3/4 3-21 and 3/4 3-22) lists the trip setpoints for instrumentation that actuates primary and secondary containment isolation. For the instrumentation that measures differential pressure between the outside atmosphere and the reactor enclosure, the TSs now list the trip setpoint as being equal or greater than 0.1 inch. The proposed revision is to change "inch" to "inches of water", since this is the required unit of measurement (as opposed, for example, to inches of mercury). This is a purely clarifying administrative change that has no safety significance, since the allowable trip setpoints are not being modified.

Item 6, Page 3/4 3-23

Table 3.3.2-3 (page 3/4 3-23) lists the isolation system response time of each isolation trip function. The 26" main steam lines are isolated by the main steam isolation valves (MSIVs) which are spring and/or pneumatic closing, piston-operated valves. They close on loss of pneumatic pressure to the valve operator. The main steam lines are isolated upon a signal of low, low (Level 2) or low, low, low (Level 3) water level in the reactor vessel or upon a signal of high radiation, high steam flow or low pressure in the steam line. The isolation signals not only initiate closure of the MSIVs but also the two small (3") motor operated drain valves. The MSIVs are required to close in a short period of time to limit the radiological consequences and loss of coolant from a steam line break outside containment but not so fast as to cause a significant pressurization transient. This quick closure is assured even upon loss of offsite power by having air operated valves. It is not necessary for the small drain valves to close as quickly as the MSIVs. The motor operated drain valves are normally powered from the safeguards buses. Upon an isolation signal, the power to these drain valves is part of the load that is automatically shed, to be subsequently picked up by the diesel generators. Each diesel generator is capable of attaining rated voltage and frequency within 10 seconds after receiving a starting signal. After rated voltage and frequency are obtained, the diesel generators are connected automatically to their respective emergency

buses. Under accident conditions, the required Class 1E loads of the divisions will be connected in a predetermined sequence to their respective diesel generator. Power to the motor operators on the drain valves is restored in less than 3 seconds after the diesels are up to speed when the 480V load center breaker is closed. In the present Table 3.3.2-3, the listed response time (in seconds) for high radiation or low pressure isolation of the main steam lines is "≦ 1.0*/≦ 13(a)**". Note "(a)" clarifies that the "isolation system instrumentation response time specified includes 10 seconds diesel generator starting and 3 seconds for sequences loading delays." In the present TSs, the response time listed for the Level 1 low water level isolation is ≦ 1.0 seconds with reference to a note that states that this value applies only to the MSIVs. To encompass the drain valve isolation times, the licensee proposes to add "/ ≦ 13(a**" after the present time to be consistent with the response times cited for other isolation functions and to the designation in the BWR standard TSs. The NRC staff has evaluated the proposed change and considers this a clarifying administrative addition with no safety considerations that were not implicit in our original evaluation of the isolation requirements and the associated instrumentation, controls and electrical power systems.

Item 7, Page 3/4 4-19

The requirements on removal of flux wire specimens on page 3/4 4-19 refers to figures B 3/4 4.6-1 and B 3/4 4.6-2. The latter was not included in the TSs issued by the Commission (NUREG-1149). The reference to the second figure is an error which the licensee proposes to correct by the requested changes. The proposed change is acceptable since it corrects an error in the Bases (which are not part of the TSs).

Item 8, Page 3/4 4-23

Section 3/4 4.7 of the TSs, page 3/4 4-23, describes the operability requirements for the MSIVs, specifically, that the valves achieve full closure in no less than 3 and no more than 5 seconds. The action statement provides 8 hours to restore operability prior to isolating the line. The MSIVs are isolation valves and are included with other isolation valves in Table 3.6.3-1 (page 3/4 6-17). The action statement for Table 3.6.3-1 allows four hours to restore operability prior to isolating the penetration. Generally, when there is an apparent conflict in the TS requirements, the more restrictive requirement is controlling. The licensee had proposed to change the 8 hour requirement in section 3/4 4/7 to 4 hours to be consistent. However, there is a basis for the 8 hours and it is in all the BWR standard TSs (NUREG-0123 revision 1, 2 and 3) and in the TSs issued for other plants (e.g. NUREG-1142 for River Bend, NUREG-1202 for Hope Creek, etc.) as well as Limerick's TSs. The 8 hours restoration time applies (vs 4 hours) as long as the MSIVs close within 5 seconds. With agreement of the licensee, this proposed change is not being processed as part of the subject amendment.

Item 9, Page 3/4 5-4, Item 10, Page 3/4 5-5,
Item 21, Page 3/4 7-9, Item 22, Page 3/4 7-10

The High Pressure Coolant Injection (HPCI) System is required to be operable whenever reactor steam dome pressure is more than 200 psig. Likewise, the Automatic Depressurization System (ADS) and Reactor Core Isolation Cooling (RCIC) System are required to be operable whenever the reactor pressure is more than 100 psig and 150 psig, respectively. The HPCI and RCIC systems use turbine-driven pumps and thus require sufficient steam pressure to operate. Testing the ADS valves also requires sufficient steam pressure to verify operability. To allow plants to get out of the shutdown mode, there is a note to the surveillance test requirements that allows the operability tests to be performed "within 12 hours after reactor steam pressure is adequate to perform the test". No directions were given, however, for the condition whereby the surveillance fails and/or HPCI/RCIC/ADS operability cannot be demonstrated during the 12 hour period following the availability of sufficient steam supply. The licensee has proposed to add a clarifying sentence to the existing notes. The added sentence would specify that in the event the system (i.e, HPCI, RCIC or ADS) is not successfully demonstrated to be operable during the 12 hour period, then the reactor dome pressure would be reduced to below that pressure at which the system is required to be operable (i.e., below 200 psig if the HPCI system is found inoperable, below 150 psig if the RCIC is involved and below 100 psig for the ADS system). The staff noted that there was no time limit specified to take this action. As proposed, the wording could be interpreted as requiring an immediate reduction in reactor pressure if the system has not been determined to be operable. The intent of the requirement is that during startup, the operability of the ECCS systems be demonstrated as soon as possible in the startup mode prior to reaching any significant power level. The operability of the systems can be determined within 12 hours but if a problem is detected, it is not always possible to diagnose the cause without steam to operate the turbines. If the HPCI, RCIC or an ADS valve is found to be inoperable while the plant is at power, the LCOs allow operation for 14 days before shutdown is required. If these systems are found to be inoperable during startup, the intent is that the inoperable equipment be fixed before proceeding with power ascension. To provide a reasonable time to troubleshoot potential problems that may be detected in these ECCS systems during startups, the staff and license agreed to a time limit of 72 hours before reactor pressure has to be reduced below the point where the systems are not required to be operable (e.g., below 200 psig for the HPCI system). This clarification only permits the plant to hold pressure at a point where sufficient steam is available to operate the HPCI and RCIC pumps for testing; it does not permit power ascension to continue. The staff concludes that the sentence that is proposed to be added to the note associated with the surveillance requirements is a clarification of the action to be taken. The proposed action is more restrictive than what would be permitted if the plant were at power and is acceptable.

Item 11, Page 3/4 6-9 and B 3/4 6-2

The Bases for Specification 3/4 6.1.6 page B 3/4 6-2, (which discusses the Drywell and Suppression Chamber internal pressure) limits the initial containment pressure prior to a LOCA in order to ensure that the containment peak pressure would not exceed 44.02 psig. The Limiting Condition for Operation on page 3/4 6-9, however, is not in accordance with the Bases and incorrectly restricts the internal pressure to be between 0.0 and +2.0 psig, while the Bases calls for -1.0 to +2.0 psig. The FSAR Section 6.2.1.1.4 evaluated negative pressure in the containment and determined that the primary containment was designed for a negative pressure of -5 psig. In order to achieve consistency and correct these errors, a change is proposed to page 3/4 6-9 to have it agree with the BASES by changing the limitations of the Limiting Condition for Operation to -1.0 to +2.0 psig. Further, the Bases for the drywell and suppression chamber specify that "...-1.0 to +2.0 psig.(is) for initial positive containment pressure ...." As the allowable containment pressure range is actually both negative and positive, the deletion of the word "positive" on page B 3/4 6-2 is proposed as it is incorrect.

The -1.0 psig limit, when viewed from the Bases, is more conservative in that a higher additive pressure would now be required in order to exceed the 44.02 psig peak pressure than was previously required. These proposed changes correct errors in the present TSs and are acceptable.

Item 12, Page 3/4 6-10

The drywell average air temperature is the calculated volumetric average of the temperature readings at four drywell elevations. At elevation 330' there are three installed temperature sensors, and there are also three sensors installed at elevation 320'; three at 260' and six at 248'.

The volumetric calculation requires only that one sensor at each elevation plane be read, without regard to the sensor (compass) location, i.e., only the elevation location is of interest in the calculation and not the azimuth location.

The azimuth has been listed, however, in the surveillance requirements on page 3/4 6-10 as an informational guide so that the exact location of each sensor may be readily ascertained even though the azimuth of each sensor is not a factor in the actual calculations. Because the azimuth of each sensor is listed, the relocation of any of these sensors would require an amendment to the TSs, even though the intent of the Technical Specifications clearly does not require this information as a limit.

Further, some readings taken from these sensors would be erroneous if the sensor azimuth was not changed due to the close proximity of pipes to some of the sensors. Some of these pipes are substantially different in temperature than the ambient drywell air.

The licensee proposes to revise the nomenclature of the drywell temperature sensors from "azimuth" to "quantity" to allow sensor azimuth relocation and preclude erroneous drywell readings and also to eliminate the need for amendments to the TSs each time a drywell modification calls for the relocation of a temperature sensor. In order to allow for physical limitations in the installation of equipment, the licensee also proposes to add the word "Approximate" before elevation.

The drywell average air temperature is required to be maintained below 135°F. The limitation on drywell average air temperature ensures that containment peak air temperature does not exceed the design temperature of 340°F during steam line break conditions. The average temperature is determined by using one reading from each of four elevations spaced over a height of 82 feet.

The purpose of the temperature sensors is to determine the average drywell temperature to ensure that the average temperature does not exceed 135°F. The precise location of a sensor is not important. What is more important is that the sensors are reading ambient drywell air temperatures. The proposed changes to the TSs will permit the licensee to locate the sensors so they are not near steam pipes, coolers or other equipment that would distort the temperatures readings. The proposed changes are to assure that the sensors will more accurately achieve the intended function. The proposed changes to the TSs will support the intended purpose of obtaining representative measurements of ambient air temperatures in the drywell and are acceptable.

Item 13, Page 3/4 6-12

Section 3.6.2.1 of the TSs (page 3/4 6-12) specifies limits on the average temperature of water in the suppression pool. To measure the average temperature, the TSs require that at least eight indicators be operable. There are eight locations in the suppression pool where temperature instruments are located. More than one temperature instrument is located at each location. The present TS's call for the operability of at least eight indicators without a specification as to their location.

The licensee has proposed to modify the TSs by adding an additional limitation that one of the indicators in each of the eight locations be operational. This additional limitation or control will help to ensure that the average temperature is being measured during surveillance testing and is acceptable.

Item 14, Page 3/4 6-47, Item 15, Page 3/4 6-52

Section 3.6.5.1.2 of the TSs (page 3/4 6-47) specifies the operability requirements for the refueling area secondary containment integrity. Section 3.6.5.3 of the TSs specifies the operability requirements for the standby gas treatment system (SGTS). There is a note at the bottom of

each page which states when the systems must be operable. The note states that refueling area secondary containment must be maintained "When irradiated fuel is being handled in the refueling area secondary containment and during core alterations and operations with a potential for draining the reactor." The note on operability for the SGTS is similar. The use of the "and" type logic is incorrect. The present wording could be interpreted as only requiring secondary containment integrity when all three conditions are present. The licensee proposes to replace the word "and" with "or" to correctly state that the systems must be operable when any one or more of the three conditions exist. The proposed changes are clarifications and are acceptable.

Item 16, Page 3/4 6-23, Item 17, Page 3/4 6-42

Table 3.6.3-1 lists the primary containment isolation valves. On page 3/4 6-23 and in note 16 to this table, there is a typographical error in that the penetration number for the tip purge check valve is listed as "035A" when it should be "035B". The proposed change corrects an error and is acceptable.

Item 18, Page 3/4 6-42

There are three pages of notes to Table 3.6.3-1 (mentioned above). Note 17 applies to two excess flow check valves on the recirculation pump cooler flow instrument lines. The instrument lines are connected to a closed cooling water system inside containment and can leak only if the line or instrument should rupture. The note presently states that "leaktightness of the line is verified during the integrated leak rate test (Type A test). To clarify that these excess flow check valves are only tested during the ILRT, the proposed change is to add a sentence stating that "the excess flow check valves are subject to operability testing, but no Type C test is performed or required". The proposed change is acceptable in that it is a clarification and does not modify any of the existing requirements.

Item 19, Page 3/4 6-17, Item 20, Page 3/4 6-18

The instrumentation lines inside containment include lines for Reactor Water Cleanup, Reactor Core Isolation Cooling, High Pressure Coolant Injection, and Drywell Sump level. Although all of these instrument lines might be indirectly described as "reactor" instrument lines, they are generally described by their own system name such as RWCU instrument, or RCIC instrument line. The present TSs on pages 3/4 6-17 and 3/4 6-18 refer to "reactor" instrument lines listed in Table 3.6.3-1 and do not reference the other system instrument lines such as RCIC, HPCI and RWCU that are also listed in Table 3.6.3-1.

The proposed change is to delete "reactor" and reference only "instrumentation" line excess flow check valves. This proposed change would then allow all of the instrument lines to be referenced, rather than only the reactor instrument lines. The proposed change constitutes an additional control and is acceptable.

Item 23, Page 3/4 8-1

Section 3.8.1.1 of the TSs specifies the requirements for A.C. electrical power sources that have to be operable. Action item b. describes the requirements for verifying the operability of the remaining A.C. power sources if two of the four diesel generators become inoperable. Action item e describes the requirements for verifying the operability of all required systems, subsystems, trains, components and devices that depend on the remaining A.C. power sources if two of the four diesel generators become inoperable. Both action items pertain to the same plant condition. Action item e now has a statement referring the operators to also see action item b. The proposed change is to add a similar statement to action item b to "Also see action item e of 3.8.1.1". This is a purely administrative change and is acceptable. However, page 3/4 8-1 is not being revised by this amendment. The clarifying sentence will be included in the more extensive revisions to page 3/4 8-1 which the licensee has proposed in an application dated September 9, 1988 on Diesel Generator Testing. Staff review of the latter has essentially been completed.

Item 24, Page 3/4 6-16

The proposed change is to correct the address and the addressee for the monthly operating reports required to be submitted to the USNRC by Section 6.9.1.6. The reports will be sent to "ATTN: Document Control Desk". This is a purely administrative change with no safety significance and is acceptable.

Item 25, Page 3/4 1-2

In Section 4.1.2, the surveillance requirements on reactivity anomalies require that the reactivity equivalence of the difference between the actual Rod Density and the predicted Rod Density shall be verified to be less than or equal to 1% delta K/K. However, the reactor must first be in operational condition 1 or 2 in order to carry out the surveillance (i.e., in power operation or startup). It seems rather obvious that the reactor has to be critical in order to perform the surveillance and that the reactor has to be in operable condition 2 (startup) in order to go critical. To make this clear, the licensee proposes to add "note C" to Section 4.1.2 to state that "the provisions of Specification 4.0.4 are not applicable". Specification 4.0.4 states:

> Entry into an operational condition or other specified applicable condition shall not be made unless the surveillance requirement(s) associated with the Limiting Condition for Operation have been performed within the applicable surveillance interval or as otherwise specified."

The proposed change would allow entry into conditions 1 or 2 prior to the completion of the surveillance requirements. The proposed change is a clarification and does not change the requirement. The proposed change is acceptable.

Item 26, Page 3/4 3-8

Table 4.3.1.1-1 on "Reactor Protection System Instrumentation Surveillance Requirements" has 10 notes associated with the Table. Note g calls for verification of core flow using baseline data obtained during the startup testing program. All of the startup test programs were completed prior to the commercial operation date (February 1, 1986) so this note is no longer applicable. Deletion of Note g is acceptable.

Item 27, Page 3/4 3-100

Section 3.11.1.1 of the TSs requires that the concentration of radioactive material released in liquid effluents to unrestricted areas shall be limited to the concentrations specified in 10 CFR Part 20, Appendix B, Table II, Column 2 for radionuclides other than dissolved or entrained noble gases. To ensure compliance with this limit, there is a surveillance requirement that specifies that all radioactive liquid wastes shall be sampled and analyzed according to the program in Table 4.11.1.1.1-1 (page 3/4 11-2). The Table specifies the sampling frequency, the minimum analysis frequency, the type of activity to be measured and the lower limit of detection (LLD) for each type of activity. There is a whole page associated with this Table describing how the LLD is defined and how it is determined. For both batch and continuous releases, the LLD for principal gamma emitters is listed as 5×10^{-7} microcuries/ml. The Table also specifies the principal gamma emitters for which the LLD specification applies.

Section 3.3.7.11 of the TSs specifies the operability requirements on the radioactive liquid effluent monitoring instrumentation. This section requires that the instrumentation listed in the associated Table (Table 3.3.11-1) shall be operable with their alarm/trip setpoints set to ensure that the limits of Specification 3.11.1.1 (discussed above) are not exceeded. The notes for this table specify what actions are to be taken if the minimum number of instrument channels are not available. One action specified (when the minimum number of instrument channels is not available) requires sampling and analysis in accordance with Specification 4.11.1.1.1 discussed in the previous paragraph. Another action specified

is to collect and analyse grab samples for gross radioactivity (beta or gamma) at a limit of detection of 10^{-7} microcuries/ml. To be consistent with Specification 4.11.1.1.1, the licensee proposes to changes this LLD to 5×10^{-7} microcuries/ml. The proposed change is acceptable.

Item 28, Page 3/4 3-94

Limerick Units 1 and 2 have a common control room on the 269' elevation. Likewise, the auxiliary equipment room located on the 289' elevation above the control room is common to both units. The auxiliary equipment room is designated as fire zone 25 in the Limerick Fire Protection Evaluation Report (FPER, page 5-40). Table 3.3.7.9-1 of the TSs lists the fire protection instrumentation that must be operable in each fire zone. For Fire Zone 25, the present TSs list fifteen heat detectors as being installed in the raised non-Power Generation Control Complex for Unit 1. However, as shown in Figure B-21 of the FPER, two of the fifteen heat detectors are on the Unit 2 side and will be included in future TSs for Unit 2, but should not have been included in the Zone 25 listing for Unit 1. The proposed change is to revise the number of heat detectors from 15 to 13. The proposed change corrects an error and is acceptable.

3.0 ENVIRONMENTAL CONSIDERATION

This amendment involves changes to a requirement with respect to the installation or use of facility components located within the restricted area as defined in 10 CFR Part 20 and changes to the surveillance requirements. The 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 this amendment involves no significant hazards consideration and there has been no public comment on such finding. Accordingly, this 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 nor environmental assessment need be prepared in connection with the issuance of this amendment.

4.0 CONCLUSION

The Commission made a proposed determination that the amendment involves no significant hazards consideration which was published in the Federal Register (54 FR 18176) on April 27, 1989 and consulted with the State of Pennsylvania. No public comments were received and the State of Pennsylvania did not have any comments.

The staff 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, and

(2) such activities will be conducted in compliance with the Commission's regulations and the issuance of this amendment will not be inimical to the common defense and the security nor to the health and safety of the public.

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Dated: June 22, 1989