August 8, 1984

Docket No.: 50-373

Mr. Dennis L. Farrar
Director of Nuclear Licensing
Commonwealth Edison Company
P. O. Box 767
Chicago, Illinois 60690

Dear Mr. Farrar:

SUBJECT: AMENDMENT NO. 18 TO FACILITY OPERATING LICENSE NO. NPF-11-
LA SALLE COUNTY STATION, UNIT 1

The Nuclear Regulatory Commission has issued the enclosed Amendment No. 18 to Facility Operating License No. NPF-11 for the La Salle County Station, Unit 1. The amendment is in response to Commonwealth Edisons Company's letters dated January 13, 1984, March 22, 1984 and April 5, 1984 which you submitted to revise the La Salle County Station, Unit 1 Technical Specifications to reflect changes incorporated into the La Salle County Station, Unit 2 Technical Specifications.

A copy of the related safety evaluation supporting Amendment No. 18 to Facility Operating License NPF-11 is enclosed.

Sincerely,

A. Schwencer, Chief
Licensing Branch No. 2
Division of Licensing

Enclosures:
1. Amendment No. 18 to NPF-11
2. Staff Evaluation

cc w/enclosures:
See next page

LB#2/DL	LB#2/DL	LB#2/DL	OELD
ABournia:dh	PShuttleworth	ASchwencer	CWoodhead
07/26/84	07/26/84	07/27/84	07/27/84

DISTRIBUTION
See Attached

8/8/84

3. This amendment is effective on the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

A. Schwencer, Chief
Licensing Branch No. 2
Division of Licensing

Attachment:
Changes to the Technical
Specifications

Date of Issuance: August 8, 1984

LB#2/DL	*LB#2/DL	*LB#2/DL	*OELD
ABournia:dh	PShuttleworth	ASchwencer	CWoodhead
07/06/84	07/ /84	07/8 /84	07/ /84

*See previous concurrence

August 8, 1984

AMENDMENT NO. 18 TO FACILITY OPERATING LICENSE NO. NPF-11-
LA SALLE COUNTY STATION, UNIT 1

DISTRIBUTION
Docket File 50-373
NRC PDR
Local PDR
PRC System
NSIC
LB#2 Reading
PShuttleworth
ABournia
TNovak
J Saltzman, SAB
CWoodhead
CMiles
HDenton
JRutbert
AToalston
WMiller, LFMB
NGrace
EJordan
LHarmon
DBrinkman, SSPB

COMMONWEALTH EDISON COMPANY

DOCKET NO. 50-373

LA SALLE COUNTY STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 18
License No. NPF-11

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

   A. The application for amendment filed by the Commonwealth Edison Company, dated January 13, 1984, March 22, 1984 and April 5, 1984, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's 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 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 set forth in 10 CFR Chapter I;

   D. The issuance of this amendment will not be inimical to the common defense and security or 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 the Faciltiy Operating License No. NPF-11 is hereby amended to read as follows:

   (2) Technical Specifications and Environmental Protection Plan

   The Technical Specifications contained in Appendix A, as revised through Amendment No. 18, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This amendment is effective ~~as~~ on the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

A. Schwencer, Chief
Licensing Branch No. 2
Division of Licensing

Attachment:
Changes to the Technical
Specifications

Date of Issuance: July 1984

LB#2/DL	LB#2/DL	LB#2/DL	OELD
ABournia:dh	JPShuttleworth	ASchwencer	TCwoodhead without change
07/26/84	07/26/84	07/27/84	07/27/84

ATTACHMENT TO LICENSE AMENTMENT NO. 18
FACILITY OPERATING LICENSE NO. NPF-11
DOCKET NO. 50-373

Replace the following pages of the Appendix "A" Technical Specification with the enclosed pages. The revised pages are identified by Amendment number and contain verticle lines indicating the area change.

REMOVE	INSERT
II	II
VIII	VIII
XV	XV
no pages	XIX thru XXIII
1-9	1-9
2-1	2-1
2-4	2-4
no pages	2-4(a)
B2-1	B2-1
B2-4	B2-4
3/4 1-1	3/4 1-1
3/4 1-3 thru 3/4 1-6	3/4 1-3 thru 3/4 1-6
3/4 1-8	3/4 1-8
3/4 1-9	3/4 1-9
3/4 1-11	3/4 1-11
3/4 1-14	3/4 1-14
3/4 1-19	3/4 1-19
3/4 2-1	3/4 2-1
3/4 2-3 thru 3/4 2-5	3/4 2-3 thru 3/4 2-5
3/4 3-1	3/4 3-1
3/4 3-4	3/4 3-4
3/4 3-5	3/4 3-5
3/4 3-11	3/4 3-11
3/4 3-14 thru 3/4 3-19	3/4 3-14 thru 3/4 3-19
3/4 3-39	3/4 3-39
3/4 3-41	3/4 3-41
3/4 3-53	3/4 3-53
no pages	3/4 3-53(a)
3/4 3-54	3/4 3-54
3/4 3-58	3/4 3-58
3/4 3-60	3/4 3-60
3/4 3-63	3/4 3-63
3/4 3-70	3/4 3-70
3/4 3-72	3/4 3-72
3/4 3-81 thru 3/4 3-84	3/4 3-81 thru 3/4 3-84
3/4 3-90	3/4 3-90
3/4 4-1	3/4 4-1
no pages	3/4 4-1(a)
3/4 4-2	3/4 4-2
3/4 4-3	3/4 4-3
3/4 4-5	3/4 4-5
3/4 4-7	3/4 4-7
3/4 4-13	3/4 4-13
3/4 4-14	3/4 4-14

REMOVE	INSERT
3/4 4-17	3/4 4-17
3/4 4-19	3/4 4-19
3/4 4-23	3/4 4-23
3/4 4-24	3/4 4-24
3/4 5-3 thru 3/4 5-5	3/4 5-3 thru 3/4 5-5
3/4 5-8	3/4 5-8
3/4 5-9	3/4 5-9
3/4 6-2	3/4 6-2
3/4 6-3	3/4 6-3
3/4 6-5	3/4 6-5
3/4 6-8	3/4 6-8
3/4 6-9	3/4 6-9
3/4 6-11	3/4 6-11
3/4 6-15 thru 3/4 6-21	3/4 6-15 thru 3/4 6-21
3/4 6-24 thru 3/4 6-28	3/4 6-24 thru 3/4 6-28
3/4 6-32 thru 3/4 6-38	3/4 6-32 thru 3/4 6-38
3/4 6-40	3/4 6-40
3/4 6-41	3/4 6-41
3/4 7-8	3/4 7-8
3/4 7-12	3/4 7-12
3/4 7-14	3/4 7-14
3/4 7-17	3/4 7-17
3/4 7-18	3/4 7-18
3/4 7-22	3/4 7-22
3/4 7-24	3/4 7-24
3/4 7-25	3/4 7-25
3/4 7-27 thru 3/4 7-33	3/4 7-27 thru 3/4 7-33
3/4 7-34 thru 3/4 7-45	no pages
3/4 8-1	3/4 8-1
3/4 8-2	3/4 8-2
3/4 8-4 thru 3/4 8-10	3/4 8-4 thru 3/4 8-10
3/4 8-12	3/4 8-12
3/4 8-14 thru 3/4 8-17	3/4 8-14 thru 3/4 8-17
3/4 8-19	3/4 8-19
3/4 8-21	3/4 8-21
3/4 8-24	3/4 8-24
3/4 8-26	3/4 8-26
3/4 8-27	3/4 8-27
3/4 8-31	3/4 8-31
3/4 9-4	3/4 9-4
3/4 9-16	3/4 9-16
3/4 9-17	3/4 9-17
3/4 11-3	3/4 11-3
3/4 11-9	3/4 11-9
3/4 11-12 thru 3/4 11-14	3/4 11-12 thru 3/4 11-14
3/4 11-19	3/4 11-19
3/4 12-1	3/4 12-1
3/4 12-4	3/4 12-4
B 3/4 0-1	B 3/4 0-1
B 3/4 1-1	B 3/4 1-1
B 3/4 1-2	B 3/4 1-2
B 3/4 1-5	B 3/4 1-5

REMOVE	INSERT
B 3/4 2-1	B 3/4 2-1
B 3/4 2-3	B 3/4 2-3
B 3/4 3-6	B 3/4 3-6
B 3/4 4-1	B 3/4 4-1
B 3/4 5-1	B 3/4 5-1
B 3/4 6-2	B 3/4 6-2
B 3/4 7-3 thru B 3/4 7-5	B 3/4 7-3 thru B 3/4 7-5
B 3/4 11-1	B 3/4 11-1
B 3/4 11-3	B 3/4 11-3
B 3/4 12-1	B 3/4 12-1
5-1	5-1
6-3	6-3
6-11	6-11
6-13	6-13
6-14	6-14
6-20	6-20
6-28	6-28
6-29	6-29

SECTION

DEFINITIONS (Continued)

	PAGE
1.25 OPERABLE - OPERABILITY	1-4
1.26 OPERATIONAL CONDITION - CONDITION	1-4
1.27 PHYSICS TESTS	1-4
1.28 PRESSURE BOUNDARY LEAKAGE	1-5
1.29 PRIMARY CONTAINMENT INTEGRITY	1-5
1.30 PROCESS CONTROL PROGRAM	1-5
1.31 PURGE - PURGING	1-5
1.32 RATED THERMAL POWER	1-5
1.33 REACTOR PROTECTION SYSTEM RESPONSE TIME	1-5
1.34 REPORTABLE OCCURRENCE	1-6
1.35 ROD DENSITY	1-6
1.36 SECONDARY CONTAINMENT INTEGRITY	1-6
1.37 SHUTDOWN MARGIN	1-6
1.38 SOLIDIFICATION	1-6
1.39 SOURCE CHECK	1-7
1.40 STAGGERED TEST BASIS	1-7
1.41 THERMAL POWER	1-7
1.42 TURBINE BYPASS RESPONSE TIME	1-7
1.43 UNIDENTIFIED LEAKAGE	1-7
1.44 VENTILATION EXHAUST TREATMENT SYSTEM	1-7
1.45 VENTING	1-7

INDEX

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

SECTION		PAGE
3/4.7 PLANT SYSTEMS		
3/4.7.1	CORE STANDBY COOLING SYSTEM - EQUIPMENT COOLING WATER SYSTEMS	
	Residual Heat Removal Service Water System	3/4 7-1
	Diesel Generator Cooling Water System	3/4 7-2
	Ultimate Heat Sink	3/4 7-3
3/4.7.2	CONTROL ROOM AND AUXILIARY ELECTRIC EQUIPMENT ROOM EMERGENCY FILTRATION SYSTEM	3/4 7-4
3/4.7.3	REACTOR CORE ISOLATION COOLING SYSTEM	3/4 7-7
3/4.7.4	SEALED SOURCE CONTAMINATION	3/4 7-9
3/4.7.5	FIRE SUPPRESSION SYSTEMS	
	Fire Suppression Water System	3/4 7-11
	Deluge and/or Sprinkler Systems	3/4 7-14
	CO_2 Systems	3/4 7-17
	Fire Hose Stations	3/4 7-18
3/4.7.6	FIRE RATED ASSEMBLIES	3/4 7-22
3/4.7.7	AREA TEMPERATURE MONITORING	3/4 7-24
3/4.7.8	STRUCTURAL INTEGRITY OF CLASS I STRUCTURES	3/4 7-26
3/4.7.9	SNUBBERS	3/4 7-27
3/4.7.10	MAIN TURBINE BYPASS SYSTEM	3/4 7-33

SECTION PAGE

3/4.7 PLANT SYSTEMS

3/4.7.1 CORE STANDBY COOLING SYSTEM - EQUIPMENT COOLING WATER SYSTEMS..... B 3/4 7-1
3/4.7.2 CONTROL ROOM EMERGENCY FILTRATION SYSTEM..... B 3/4 7-1
3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM..... B 3/4 7-1
3/4.7.4 SEALED SOURCE CONTAMINATION..... B 3/4 7-2
3/4.7.5 FIRE SUPPRESSION SYSTEMS..... B 3/4 7-2
3/4.7.6 FIRE RATED ASSEMBLIES..... B 3/4 7-3
3/4.7.7 AREA TEMPERATURE MONITORING..... B 3/4 7-3
3/4.7.8 STRUCTURAL INTEGRITY OF CLASS I STRUCTURES..... B 3/4 7-3
3/4.7.9 SNUBBERS..... B 3/4 7-3
3/4.7.10 MAIN TURBINE BYPASS SYSTEM..... B 3/4 7-5

3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1 and 3/4.8.2 A.C. SOURCES AND ONSITE POWER DISTRIBUTION SYSTEMS..... B 3/4 8-1
3/4.8.3 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES..... B 3/4 8-2

3/4.9 REFUELING OPERATIONS

3/4.9.1 REACTOR MODE SWITCH..... B 3/4 9-1
3/4.9.2 INSTRUMENTATION..... B 3/4 9-1
3/4.9.3 CONTROL ROD POSITION..... B 3/4 9-1
3/4.9.4 DECAY TIME..... B 3/4 9-1
3/4.9.5 COMMUNICATIONS..... B 3/4 9-1
3/4.9.6 CRANE AND HOIST..... B 3/4 9-1
3/4.9.7 CRANE TRAVEL..... B 3/4 9-2
3/4.9.8 and 3/4.9.9 WATER LEVEL - REACTOR VESSEL and WATER LEVEL - SPENT FUEL STORAGE POOL..... B 3/4 9-2
3/4.9.10 CONTROL ROD REMOVAL..... B 3/4 9-2
3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION..... B 3/4 9-2

LIST OF FIGURES

FIGURE		PAGE
3.1.5-1	SODIUM PENTABORATE SOLUTION TEMPERATURE/ CONCENTRATION REQUIREMENTS	3/4 1-21
3.1.5-2	SODIUM PENTABORATE ($Na_2B_{10}O_{16} \cdot 10\ H_2O$) VOLUME/CONCENTRATION REQUIREMENTS	3/4 1-22
3.2.1-1	MAXIMUM AVERAGE PLANAR LINEAR HEAT GENERATION RATE (MAPLHGR) VERSUS AVERAGE PLANAR EXPOSURE, INITIAL CORE FUEL TYPES 8CR183, 8CR233, AND 8CR711	3/4 2-2
3.2.3-1	MINIMUM CRITICAL POWER RATIO (MCPR) VERSUS τ AT RATED FLOW	3/4 2-5
3.2.3-2	K_f FACTOR	3/4 2-6
3.4.6.1-1	MINIMUM REACTOR VESSEL METAL TEMPERATURE VS. REACTOR VESSEL PRESSURE	3/4 4-18
4.7-1	SAMPLE PLAN 2) FOR SNUBBER FUNCTIONAL TEST	3/4 7-32
B 3/4 3-1	REACTOR VESSEL WATER LEVEL	B 3/4 3-7
B 3/4.4.6-1	CALCULATED FAST NEUTRON FLUENCE (E>1MeV) at 1/4 T AS A FUNCTION OF SERVICE LIFE	B 3/4 4-7
5.1.1-1	EXCLUSION AREA AND SITE BOUNDARY FOR GASEOUS AND LIQUID EFFLUENTS	5-2
5.1.2-1	LOW POPULATION ZONE	5-3
6.1-1	CORPORATE MANAGEMENT	6-11
6.1-2	UNIT ORGANIZATION	6-12
6.1-3	MINIMUM SHIFT CREW COMPOSITION	6-13

INDEX

LIST OF TABLES

TABLE		PAGE
1.1	SURVEILLANCE FREQUENCY NOTATION	1-8
1.2	OPERATIONAL CONDITIONS	1-9
2.2.1-1	REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS	2-4
B2.1.2-1	UNCERTAINTIES USED IN THE DETERMINATION OF THE FUEL CLADDING SAFETY LIMIT	B 2-4
B2.1.2-2	NOMINAL VALUES OF PARAMETERS USED IN THE STATISTICAL ANALYSIS OF FUEL CLADDING INTEGRITY SAFETY LIMIT	B 2-5
B2.1.2-3	RELATIVE BUNDLE POWER DISTRIBUTION USED IN THE GETAB STATISTICAL ANALYSIS	B 2-6
B2.1.2-4	R-FACTOR DISTRIBUTION USED IN GETAB STATISTICAL ANALYSIS	B 2-7
3.3.1-1	REACTOR PROTECTION SYSTEM INSTRUMENTATION	3/4 3-2
3.3.1-2	REACTOR PROTECTION SYSTEM RESPONSE TIMES	3/4 3-6
4.3.1.1-1	REACTOR PROTECTION SYSTEM INSTRUMENTAION SURVEILLANCE REQUIREMENTS	3/4 3-7
3.3.2-1	ISOLATION ACTUATION INSTRUMENTATION	3/4 3-11
3.3.2-2	ISOLATION ACTUATION INSTRUMENTATION SETPOINTS	3/4 3-15
3.3.2-3	ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME	3/4 3-18
4.3.2.1-1	ISOLATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS	3/4 3-20
3.3.3-1	EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION	3/4 3-24
3.3.3-2	EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS	3/4 3-28
3.3.3-3	EMERGENCY CORE COOLING SYSTEM RESPONSE TIMES	3/4 3-31
4.3.3.1-1	EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS	3/4 3-32
3.3.4.1-1	ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION	3/4 3-36

LIST OF TABLES (Continued)

TABLE		PAGE
3.3.4.1-2	ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION SETPOINTS	3/4 3-37
4.3.4.1-1	ATWS RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS	3/4 3-38
3.3.4.2-1	END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION	3/4 3-41
3.3.4.2-2	END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM SETPOINTS	3/4 3-42
3.3.4.2-3	END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME	3/4 3-43
4.3.4.2.1-1	END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM SURVEILLANCE REQUIREMENTS	3/4 3-44
3.3.5-1	REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION	3/4 3-46
3.3.5-2	REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS	3/4 3-48
4.3.5.1-1	REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS	3/4 3-49
3.3.6-1	CONTROL ROD WITHDRAWAL BLOCK INSTRUMENTATION	3/4 3-51
3.3.6-2	CONTROL ROD WITHDRAWAL BLOCK INSTRUMENTATION SETPOINTS	3/4 3-53
4.3.6-1	CONTROL ROD WITHDRAWAL BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS	3/4 3-54
3.3.7.1-1	RADIATION MONITORING INSTRUMENTATION	3/4 3-57
4.3.7.1-1	RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS	3/4 3-59
3.3.7.2-1	SEISMIC MONITORING INSTRUMENTATION	3/4 3-61
4.3.7.2-1	SEISMIC MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS	3/4 3-62
3.3.7.3-1	METEOROLOGICAL MONITORING INSTRUMENTATION	3/4 3-64

LIST OF TABLES (Continued)

TABLE		PAGE
4.3.7.3-1	METEOROLOGICAL MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS	3/4 3-65
3.3.7.4-1	REMOTE SHUTDOWN MONITORING INSTRUMENTATION	3/4 3-67
4.3.7.4-1	REMOTE SHUTDOWN MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS	3/4 3-68
3.3.7.5-1	ACCIDENT MONITORING INSTRUMENTATION	3/4 3-70
4.3.7.5-1	ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS	3/4 3-71
3.3.7.9-1	FIRE DETECTION INSTRUMENTATION	3/4 3-76
3.3.7.10-1	RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION	3/4 3-82
4.3.7.10-1	RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS	3/4 3-84
3.3.7.11-1	RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION	3/4 3-87
4.3.7.11-1	RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS	3/4 3-89
3.3.8-1	FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION	3/4 3-93
3.3.8-2	FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION SETPOINTS	3/4 3-94
4.3.8.1-1	FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS	3/4 3-95
3.4.3.2-1	REACTOR COOLANT SYSTEM PRESSURE ISOLATION VALVES	3/4 4-9
3.4.4-1	REACTOR COOLANT SYSTEM CHEMISTRY LIMITS	3/4 4-12
4.4.5-1	PRIMARY COOLANT SPECIFIC ACTIVITY SAMPLE AND ANALYSIS PROGRAM	3/4 4-15
4.4.6.1.3-1	REACTOR VESSEL MATERIAL SURVEILLANCE PROGRAM-- WITHDRAWAL SCHEDULE	3/4 4-19
4.6.1.5-1	TENDON SURVEILLANCE	3/4 6-11

LIST OF TABLES (Continued)

TABLE		PAGE
4.6.1.5-2	TENDON LIFT-OFF FORCE	3/4 6-12
3.6.3-1	PRIMARY CONTAINMEN ISOLATION VALVES	3/4 6-24
3.6.5.2-1	SECONDARY CONTAINMENT VENTILATION SYSTEM AUTOMATIC ISOLATION VALVES	3/4 6-39
3.7.5.2-1	DELUGE AND SPRINKLER SYSTEMS	3/4 7-16
3.7.5.4-1	FIRE HOSE STATIONS	3/4 7-19
3.7.7-1	AREA TEMPERATURE MONITORING	3/4 7-25
4.8.1.1.2-1	DIESEL GENERATOR TEST SCHEDULE	3/4 8-7
8.4.2.3.2-1	BATTERY SURVEILLANCE REQUIREMENTS	3/4 8-18
3.8.3.2-1	PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES	3/4 8-24
3.8.3.3-1	MOTOR-OPERATED VALVES THERMAL OVERLOAD PROTECTION	3/4 8-27
3.11.1-1	MAXIMUM PERMISSIBLE CONCENTRATION OF DISSOLVED OR ENTRAINED NOBLE GASES RELEASED FROM THE SITE TO UNRESTRICTED AREAS IN LIQUID WASTE	3/4 11-2
4.11.1-1	RADIOACTIVE LIQUID WASTE SAMPLING AND ANALYSIS PROGRAM	3/4 11-3
4.11.2-1	RADIOACTIVE GASEOUS WASTE SAMPLING, AND ANALYSIS PROGRAM	3/4 11-10
3.12.1-1	RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM	3/4 12-3
3.12.1-2	REPORTING LEVELS FOR RADIOACTIVITY CONCENTRATIONS IN ENVIRONMENTAL SAMPLES	3/4 12-6
4.12.1-1	MINIMUM VALUES FOR THE LOWER LIMITS OF DETECTION	3/4 12-7
B3.2.1-1	SIGNIFICANT INPUT PARAMETERS TO THE LOSS-OF-COOLANT ACCIDENT ANALYSIS	B 3/4 2-2
B3/4.4.6-1	REACTOR VESSEL TOUGHNESS	B 3/4 4-6
5.7.1-1	COMPONENT CYCLIC OR TRANSIENT LIMITS	5-6

TABLE 1.2

OPERATIONAL CONDITIONS

CONDITION	MODE SWITCH POSITION	AVERAGE REACTOR COOLANT TEMPERATURE
1. POWER OPERATION	Run	Any temperature
2. STARTUP	Startup/Hot Standby	Any temperature
3. HOT SHUTDOWN	Shutdown# ***	> 200°F
4. COLD SHUTDOWN	Shutdown# ## ***	≤ 200°F
5. REFUELING*	Shutdown or Refuel** #	≤ 140°F

#The reactor mode switch may be placed in the Run or Startup/Hot Standby position to test the switch interlock functions provided that the control rods are verified to remain fully inserted by a second licensed operator or other technically qualified member of the unit technical staff.

##The reactor mode switch may be placed in the Refuel position while a single control rod drive is being removed from the reactor pressure vessel per Specification 3.9.10.1.

*Fuel in the reactor vessel with the vessel head closure bolts less than fully tensioned or with the head removed.

**See Special Test Exception 3.10.3

***The reactor mode switch may be placed in the Refuel position while a single control rod is being moved provided that the one-rod-out interlock is OPERABLE.

2.0 SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

2.1 SAFETY LIMITS

THERMAL POWER, Low Pressure or Low Flow

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

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With THERMAL POWER exceeding 25% of RATED THERMAL POWER and the reactor vessel steam dome pressure less than 785 psig or core flow less than 10% of rated flow, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.4.

THERMAL POWER, High Pressure and High Flow

2.1.2 The MINIMUM CRITICAL POWER RATIO (MCPR) shall not be less than 1.06 with two recirculation loop operation and shall not be less than 1.07 with single recirculation loop operation with the reactor vessel steam dome pressure greater than 785 psig and core flow greater than 10% of rated flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With MCPR less than 1.06 with two recrculation loop operation or less than 1.07 with single recirculation loop operation and the reactor vessel steam dome pressure greater than 785 psig and core flow greater than 10% of rated flow, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.4

REACTOR COOLANT SYSTEM PRESSURE

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

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

ACTION:

With the reactor coolant system pressure, as measured in the reactor vessel steam dome, above 1325 psig, be in at least HOT SHUTDOWN with reactor coolant system pressure less than or equal to 1325 psig within 2 hours and comply with the requirements of Specification 6.4.

TABLE 2.2.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Intermediate Range Monitor, Neutron Flux-High	≤ 120 divisions of full scale	≤ 122 divisions of full scale
2. Average Power Range Monitor:		
a. Neutron Flux-High, Setdown	≤ 15% of RATED THERMAL POWER	≤ 20% of RATED THERMAL POWER
b. Flow Biased Simulator Thermal Power - Upscale		
1) Two Recirculation Loop Operation		
a) Flow Biased	≤ 0.66W + 51% with a maximum of	≤ 0.66W + 54% with a maximum of
b) High Flow Clamped	≤ 113.5% of RATED THERMAL POWER	≤ 115.5% of RATED THERMAL POWER
2) Single Recirculation Loop Operation		
a) Flow Biased	≤ 0.66W + 45.7% with a maximum of	≤ 0.66W + 48.7% with a maximum of
b) High Flow Clamped	≤ 113.5% of RATED THERMAL POWER	≤ 115.5% of RATED THERMAL POWER
c. Fixed Neutron Flux-High	≤ 118% of RATED THERMAL POWER	≤ 120% of RATED THERMAL POWER
3. Reactor Vessel Steam Dome Pressure - High	≤ 1043 psig	≤ 1063 psig
4. Reactor Vessel Water Level - Low, Level 3	≥ 12.5 inches above instrument zero*	≥ 11.0 inches above instrument zero*
5. Main Steam Line Isolation Valve - Closure	≤ 8% closed	≤ 12% closed
6. Main Steam Line Radiation - High	≤ 3.0 x full power background	≤ 3.6 x full power background
7. Primary Containment Pressure - High	≤ 1.69 psig	≤ 1.89 psig
8. Scram Discharge Volume Water Level - High	≤ 767' 5¼"	≤ 767' 5¼"

18

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

TABLE 2.2.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
9. Turbine Stop Valve - Closure	≤ 5% closed	≤ 7% closed
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≥ 500 psig	≥ 414 psig
11. Reactor Mode Switch Shutdown Position	NA	NA
12. Manual Scram	NA	NA

BASES

2.0 The fuel cladding, reactor pressure vessel and primary system piping are the principal barriers to the release of radioactive materials to the environs. Safety Limits are established to protect the integrity of these barriers during normal plant operations and anticipated transients. The fuel cladding integrity Safety Limit is set such that no fuel damage is calculated to occur if the limit is not violated. Because fuel damage is not directly observable, a step-back approach is used to establish a Safety Limit such that the MCPR is not less than 1.06. MCPR greater than 1.06 for two recirculation loop operation and 1.07 for single recirculation loop operation represents a conservative margin relative to the conditions required to maintain fuel cladding integrity. The fuel cladding is one of the physical barriers which separate the radioactive materials from the environs. The integrity of this cladding barrier is related to its relative freedom from perforations or cracking. Although some corrosion or use related cracking may occur during the life of the cladding, fission product migration from this source is incrementally cumulative and continuously measurable. Fuel cladding perforations, however, can result from thermal stresses which occur from reactor operation significantly above design conditions and the Limiting Safety System Settings. While fission product migration from cladding perforation is just as measurable as that from use related cracking, the thermally caused cladding perforations signal a threshold beyond which still greater thermal stresses may cause gross rather than incremental cladding deterioration. Therefore, the fuel cladding Safety Limit is defined with a margin to the conditions which would produce onset of transition boiling, MCPR of 1.0. These conditions represent a significant departure from the condition intended by design for planned operation.

2.1.1 THERMAL POWER, Low Pressure or Low Flow

The use of the GEXL correlation is not valid for all critical power calculations at pressures below 785 psig or core flows less than 10% of rated flow. Therefore, the fuel cladding integrity Safety Limit is established by other means. This is done by establishing a limiting condition on core THERMAL POWER with the following basis. Since the pressure drop in the bypass region is essentially all elevation head, the core pressure drop at low power and flows will always be greater than 4.5 psi. Analyses show that with a bundle flow of 28×10^3 lbs/hr, bundle pressure drop is nearly independent of bundle power and has a value of 3.5 psi. Thus, the bundle flow with a 4.5 psi driving head will be greater than 28×10^3 lbs/hr. Full scale ATLAS test data taken at pressures from 14.7 psia to 800 psia indicate that the fuel assembly critical power at this flow is approximately 3.35 MWt. With the design peaking factors, this corresponds to a THERMAL POWER of more than 50% of RATED THERMAL POWER. Thus, a THERMAL POWER limit of 25% of RATED THERMAL POWER for reactor pressure below 785 psig is conservative.

Bases Table B2.1.2-1

UNCERTAINTIES USED IN THE DETERMINATION OF THE FUEL CLADDING SAFETY LIMIT*

Quantity	Standard Deviation (% of Point)
Feedwater Flow	1.76
Feedwater Temperature	0.76
Reactor Pressure	0.5
Core Inlet Temperature	0.2
Core Total Flow	
Two recirculation Loop Operation	2.5
Single recirculation Loop Operation	6.0
Channel Flow Area	3.0
Friction Factor Multiplier	10.0
Channel Friction Factor Multiplier	5.0
TIP Readings	
Two Recirculation Loop Operation	6.3
Single Recirculation Loop Operation	6.8
R Factor	1.5
Critical Power	3.6

* The uncertainty analysis used to establish the core wide Safety Limit MCPR is based on the assumption of quadrant power symmetry for the reactor core. The values herein appply to both two recirculation loop operation and single recirculation loop operation, except as noted.

3/4.1 REACTIVITY CONTROL SYSTEMS

3/4.1.1 SHUTDOWN MARGIN

LIMITING CONDITION FOR OPERATION

3.1.1 The SHUTDOWN MARGIN shall be equal to or greater than:

a. 0.38% delta k/k with the highest worth rod analytically determined, or

b. 0.28% delta k/k with the highest worth rod determined by test.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, 4 and 5.

ACTION:

With the SHUTDOWN MARGIN less than specified:

a. In OPERATIONAL CONDITION 1 or 2, reestablish the required SHUTDOWN MARGIN within 6 hours or be in at least HOT SHUTDOWN within the next 12 hours.

b. In OPERATIONAL CONDITION 3 or 4, immediately verify all insertable control rods to be inserted and suspend all activities that could reduce the SHUTDOWN MARGIN. In OPERATIONAL CONDITION 4, establish SECONDARY CONTAINMENT INTEGRITY within 8 hours.

c. In OPERATIONAL CONDITION 5, suspend CORE ALTERATIONS* and other activities that could reduce the SHUTDOWN MARGIN, and insert all insertable control rods within 1 hour. Establish SECONDARY CONTAINMENT INTEGRITY within 8 hours.

SURVEILLANCE REQUIREMENTS

4.1.1 The SHUTDOWN MARGIN shall be determined to be equal to or greater than specified at any time during the fuel cycle:

a. By measurement, prior to or during the first startup after each refueling.

b. By measurement, within 500 MWD/T prior to the core average exposure at which the predicted SHUTDOWN MARGIN, including uncertainties and calculation biases, is equal to the specified limit.

c. Within 12 hours after detection of a withdrawn control rod that is immovable, as a result of excessive friction or mechanical interference, or is untrippable, except that the above required SHUTDOWN MARGIN shall be verified acceptable with an increased allowance for the withdrawn worth of the immovable or untrippable control rod.

*Except movement of IRMs, SRMs or special movable detectors.

3/4.1.3 CONTROL RODS

CONTROL ROD OPERABILITY

LIMITING CONDITION FOR OPERATION

3.1.3.1 All control rods shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

a. With one control rod inoperable due to being immovable, as a result of excessive friction or mechanical interference, or known to be untrippable:

   1. Within 1 hour:

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

      b) Disarm the associated directional control valves* either:

         1) Electrically, or

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

      c) Comply with Surveillance Requirement 4.1.1.c.

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

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

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

   1. If the inoperable control rod(s) is withdrawn:

      a) Immediately verify:

         1) That the inoperable withdrawn control rod(s) is separated from all other inoperable withdrawn control rod(s) by at least two control cells in all directions, and

         2) The insertion capability of the inoperable withdrawn control rod(s) by inserting the control rod(s) at least one notch by drive water pressure within the normal operating range**.

      b) Otherwise, insert the inoperable withdrawn control rod(s) and disarm the associated directional control valves* either:

         1) Electrically, or

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

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*May be rearmed intermittently, under administrative control, to permit testing associated with restoring the control rod to OPERABLE status.

**The inoperable control rod may then be withdrawn to a position no further withdrawn than its position when found to be inoperable.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION (Continued)

2. If the inoperable control rod(s) is inserted:

   a) Within 1 hour disarm the associated directional control valves* either: | 18

      1) Electrically, or

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

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

3. The provisions of Specification 3.0.4 are not applicable. | 15

c. With more than 8 control rods inoperable, be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.1.1 The scram discharge volume drain and vent valves shall be demonstrated OPERABLE by:

a. At least once per 31 days verifying each valve to be open**, and | 18

b. At least once per 92 days cycling each valve through at least one complete cycle of full travel.

4.1.3.1.2 When above the low power setpoint of the RWM and RSCS, all withdrawn control rods not required to have their directional control valves disarmed electrically or hydraulically shall be demonstrated OPERABLE by moving each control rod at least one notch:

a. At least once per 7 days, and

b. At least once per 24 hours when any control rod is immovable as a result of excessive friction or mechanical interference.

4.1.3.1.3 All control rods shall be demonstrated OPERABLE by performance of Surveillance Requirements 4.1.3.2, 4.1.3.4, 4.1.3.5, 4.1.3.6 and 4.1.3.7.

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*May be rearmed intermittently, under administrative control, to permit testing associated with restoring the control rod to OPERABLE status. | 18

**These valves may be closed intermittently for testing under administrative control. | 18

SURVEILLANCE REQUIREMENTS (Continued)

4.1.3.1.4 The scram discharge volume shall be determined OPERABLE by demonstrating:

a. The scram discharge volume drain and vent valves OPERABLE, when control rods are scram tested from a normal control rod configuration of less than or equal to 50% ROD DENSITY at least once per 18 months* by verifying that the drain and vent valves:

   1. Close within 30 seconds after receipt of a signal for control rods to scram, and

   2. Open after the scram signal is reset.

b. Proper float response by performance of a CHANNEL FUNCTIONAL TEST of the scram discharge volume scram and control rod block level instrumentation after each scram from a pressurized condition.

*The provisions of Specification 4.0.4 are not applicable for entry into OPERATIONAL CONDITION 2 provided the surveillance is performed within 12 hours after achieving less than or equal to 50% ROD DENSITY.

CONTROL ROD MAXIMUM SCRAM INSERTION TIMES

LIMITING CONDITION FOR OPERATION

3.1.3.2 The maximum scram insertion time of each control rod from the fully withdrawn position to notch position 05, based on de-energization of the scram pilot valve solenoids as time zero, shall not exceed 7.0 seconds.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

a. With the maximum scram insertion time of one or more control rods exceeding 7.0 seconds:

   1. Declare the control rod(s) with the slow insertion time inoperable, and

   2. Perform the Surveillance Requirements of Specification 4.1.3.2.c at least once per 60 days when operation is continued with three or more control rods with maximum scram insertion times in excess of 7.0 seconds.

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

b. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.1.3.2 The maximum scram insertion time of the control rods shall be demonstrated through measurement with reactor coolant pressure greater than or equal to 950 psig and, during single control rod scram time tests, the control rod drive pumps isolated from the accumulators:

a. For all control rods prior to THERMAL POWER exceeding 40% of RATED THERMAL POWER following CORE ALTERATIONS* or after a reactor shutdown that is greater than 120 days,

b. For specifically affected individual control rods following maintenance on or modification to the control rod or control rod drive system which could affect the scram insertion time of those specific control rods, and

c. For at least 10% of the control rods, on a rotating basis, at least once per 120 days of operation.

*Except movement of SRM, IRM or special movable detectors or normal control rod movement.

FOUR CONTROL ROD GROUP SCRAM INSERTION TIMES

LIMITING CONDITION FOR OPERATION

3.1.3.4 The average scram insertion time, from the fully withdrawn position, for the three fastest control rods in each group of four control rods arranged in a two-by-two array, based on deenergization of the scram pilot valve solenoids as time zero, shall not exceed any of the following:

Position Inserted From Fully Withdrawn	Average Scram Insertion Time (Seconds)
45	0.45
39	0.92
25	2.05
05	3.70

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

a. With the average scram insertion times of control rods exceeding the above limits:

1. Declare the control rods with the slower than average scram insertion times inoperable until an analysis is performed to determine that required scram reactivity remains for the slow four control rod group, and

2. Perform the Surveillance Requirements of Specification 4.1.3.2.c at least once per 60 days when operation is continued with an average scram insertion time(s) in excess of the average scram insertion time limit.

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

b. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.1.3.4 All control rods shall be demonstrated OPERABLE by scram time testing from the fully withdrawn position as required by Surveillance Requirement 4.1.3.2.

CONTROL ROD SCRAM ACCUMULATORS

LIMITING CONDITION FOR OPERATION

3.1.3.5 All control rod scram accumulators shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 5*.

ACTION:

a. In OPERATIONAL CONDITION 1 or 2:

1. With one control rod scram accumulator inoperable:

a) Within 8 hours, either:

1) Restore the inoperable accumulator to OPERABLE status, or

2) Declare the control rod associated with the inoperable accumulator inoperable.

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

2. With more than one control rod scram accumulator inoperable, declare the associated control rod inoperable and:

a) If the control rod associated with any inoperable scram accumulator is withdrawn, immediately verify that at least one CRD pump is operating by inserting at least one withdrawn control rod at least one notch by drive water pressure within the normal operating range or place the reactor mode switch in the Shutdown position.

b) Insert the inoperable control rods and disarm the associated directional control valves either:

1) Electrically, or

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

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

b. In OPERATIONAL CONDITION 5 with:

1. One withdrawn control rod with its associated scram accumlator inoperable, insert the affected control rod and disarm the associated directional control valves within 1 hour, either:

a) Electrically, or

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

2. More than one withdrawn control rod with the associated scram accumulator inoperable or with no control rod drive pump operating, immediately place the reactor mode switch in the Shutdown position.

c. The provisions of Specification 3.0.4 are not applicable.

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*At least the accumulator associated with each withdrawn control rod. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

CONTROL ROD DRIVE COUPLING

LIMITING CONDITION FOR OPERATION

3.1.3.6 All control rods shall be coupled to their drive mechanisms.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 5*.

ACTION:

a. In OPERATIONAL CONDITION 1 and 2 with one control rod not coupled to its associated drive mechanism:

   1. Within 2 hours, either:

      a) If permitted by the RWM and RSCS, insert the control rod drive mechanism to accomplish recoupling and verify recoupling by withdrawing the control rod, and:

         1) Observing any indicated response of the nuclear instrumentation, and

         2) Demonstrating that the control rod will not go to the overtravel position.

      b) If recoupling is not accomplished on the first attempt or, if not permitted by the RWM or RSCS then until permitted by the RWM and RSCS, declare the control rod inoperable and insert the control rod and disarm the associated directional control valves** either:

         1) Electrically, or

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

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

b. In OPERATIONAL CONDITION 5* with a withdrawn control rod not coupled to its associated drive mechanism, within 2 hours, either:

   1. Insert the control rod to accomplish recoupling and verify recoupling by withdrawing the control rod and demonstrating that the control rod will not go to the overtravel position, or

   2. If recoupling is not accomplished, insert the control rod and disarm the associated directional control valves** either:

      a) Electrically, or

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

c. The provisions of Specification 3.0.4 are not applicable.

---

*At least each withdrawn control rod. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

**May be rearmed intermittently, under administrative control, to permit testing associated with restoring the control rod to OPERABLE status.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION (Continued)

2. With one or more control rod "Full-in" and "Full-out" position indicators inoperable:

   a) Either:

      1) When THERMAL POWER is within the low power setpoint of the RSCS:

         (a) Within one hour:

            (1) Determine the position of the control rod(s) by:

               (a) Moving the control rod, by single notch movement, to a position with an OPERABLE position indicator,

               (b) Returning the control rod, by single notch movement, to its original position, and

               (c) Verifying no control rod drift alarm at least per 12 hours, or

            (2) Move the control rod to a position with an OPERABLE position indicator, or

            (3) Declare the control rod inoperable.

         (b) Verify the position and bypassing of control rods with inoperable "Full-in" and/or "Full-out" position indicators by a second licensed operator or other technically qualified member of the unit technical staff.

      2) When THERMAL POWER is greater than the low power setpoint of the RSCS, determine the position of the control rod(s) per ACTION a.2.a) 1)(a)(1), above.

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

b. In OPERATIONAL CONDITION 5* with a withdrawn control rod position indicator inoperable, move the control rod to a position with an OPERABLE position indicator or insert the control rod.

c. The provisions of 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.1.3.7 The control rod position indication system shall be determined OPERABLE by verifying:

a. At least once per 24 hours that the position of each control rod is indicated,

b. That the indicated control rod position changes during the movement of the control rod drive when performing Surveillance Requirement 4.1.3.1.2, and

c. That the control rod position indicator corresponds to the control rod position indicated by the "Full out" position indicator when performing Surveillance Requirement 4.1.3.6b.

*At least each withdrawn control rod not applicable to control rods removed per Specifications 3.9.10.1 or 3.9.10.2.

3/4.1.5 STANDBY LIQUID CONTROL SYSTEM

LIMITING CONDITION FOR OPERATION

3.1.5 The standby liquid control system shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 5*.

ACTION:

a. In OPERATIONAL CONDITION 1 or 2:

1. With one motor operated suction valve, one pump and/or one explosive valve inoperable, restore the inoperable suction valve, pump and/or explosive valve to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

2. With the standby liquid control system inoperable, restore the system to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours.

b. In OPERATIONAL CONDITION 5*:

1. With one motor operated suction valve, one pump and/or one explosive valve inoperable, restore the inoperable suction valve, pump and/or explosive valve to OPERABLE status within 30 days or insert all insertable control rods within the next hour.

2. With the standby liquid control system inoperable, insert all insertable control rods within 1 hour.

SUREILLANCE REQUIREMENTS

4.1.5 The standby liquid control system shall be demonstrated OPERABLE:

a. At least once per 24 hours by verifying that;

1. The available volume and temperature of the sodium pentaborate solution are within the limits of Figures 3.1.5-1 and 3.1.5-2, and

2. The heat tracing circuit is OPERABLE by verifying the indicated temperature to be $\geq$ 60°F on the local indicator.

*With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

3/4.2 POWER DISTRIBUTION LIMITS

3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

LIMITING CONDITION FOR OPERATION

3.2.1 All AVERAGE PLANAR LINEAR HEAT GENERATION RATES (APLHGRs) for each type of fuel as a function of AVERAGE PLANAR EXPOSURE shall not exceed the limits shown in Figure 3.2.1-1. The limits of Figure 3.2.1-1 shall be reduced to a value of 0.85 times the two recirculation loop operation limit when in single recirculation loop operation.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION:

With an APLHGR exceeding the limits of Figure 3.2.1-1, initiate corrective action within 15 minutes and restore APLHGR to within the required limits within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.1 All APLHGRs shall be verified to be equal to or less than the limits determined from Figure 3.2.1-1:

a. At least once per 24 hours,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and at least once per 12 hours when the reactor is operating with a LIMITING CONTROL ROD PATTERN for APLHGR.

3/4.2.2 APRM SETPOINTS

LIMITING CONDITION FOR OPERATION

3.2.2 The APRM flow biased simulated thermal power-upscale scram trip setpoint (S) and flow biased simulated thermal power-upscale control rod block trip setpoint (S_{RB}) shall be established according to the following relationships:

a. Two Recirculation Loop Operation
S less than or equal to (0.66W + 51%)T
S_{RB} less than or equal to (0.66W + 42%)T

b. Single Recirculation Loop Operation
S less than or equal to (0.66W + 45.7%)T
S_{RB} less than or equal to (0.66W + 36.7%)T

where: S and S_{RB} are in percent of RATED THERMAL POWER,
W = Loop recirculation flow as a percentage of the loop recirculation flow which produces a rated core flow of 108.5 million lbs/hr,
T = Lowest value of the ratio of FRACTION OF RATED THERMAL POWER divided by the MAXIMUM FRACTION OF LIMITING POWER DENSITY. T is always less than or equal to 1.0.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION:

With the APRM flow biased simulated thermal power-upscale scram trip setpoint and/or the flow biased simulated thermal power-upscale control rod block trip setpoint set less conservatively than S or S_{RB}, as above determined, initiate corrective action within 15 minutes and restore S and/or S_{RB} to within the required limits* within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.2 The FRTP and the MFLPD for each class of fuel shall be determined, the value of T calculated, and the most recent actual APRM flow biased simulated thermal power-upscale scram and control rod block trip setpoint verified to be within the above limits or adjusted, as required:

a. At least once per 24 hours,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and at least once per 12 hours when the reactor is operating with MFLPD greater than or equal to FRTP.

*With MFLPD greater than the FRTP during power ascension up to 90% of RATED THERMAL POWER, rather than adjusting the APRM setpoints, the APRM gain may be adjusted such that APRM readings are greater than or equal to 100% times MFLPD, provided that the adjusted APRM reading does not exceed 100% of RATED THERMAL POWER, the required gain adjustment increment does not exceed 10% of RATED THERMAL POWER, and a notice of the adjustment is posted on the reactor control panel.

POWER DISTRIBUTION LIMITS

3/4.2.3 MINIMUM CRITICAL POWER RATIO

LIMITING CONDITION FOR OPERATION

3.2.3 The MINIMUM CRITICAL POWER RATIO (MCPR) shall be equal to or greater than the MCPR limit determined from Figure 3.2.3-1 times the K_f determined from Figure 3.2.3-2 for two recirculation loop operation and shall be equal to or greater than the MCPR limit determined from Figure 3.2.3-1 + 0.01 times the K_f determined from Figure 3.2.3-2 for single recirculation loop operation provided that the end-of-cycle recirculation pump trip (EOC-RPT) system is OPERABLE per Specification 3.3.4.2.

APPLICABILITY:

OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION

a. With the end-of-cycle recirculation pump trip system inoperable per Specification 3.3.4.2, operation may continue and the provisions of Specification 3.0.4 are not applicable provided that, within 1 hour, MCPR is determined to be equal to or greater than the MCPR limit shown in Figure 3.2.3-1 EOC-RPT inoperable curve, times the K_f shown in Figure 3.2.3-2.

b. With MCPR less than the applicable MCPR limit determined from Figures 3.2.3-1 and 3.2.3-2, initiate corrective action within 15 minutes and restore MCPR to within the required limit within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.3 MCPR, with:

a. τ_{ave} = 0.86 prior to performance of the initial scram time measurements for the cycle in accordance with Specification 4.1.3.2, or

b. τ_{ave} determined within 72 hours of the conclusion of each scram time surveillance test required by Specification 4.1.3.2,

shall be determined to be equal to or greater than the applicable MCPR limit determined from Figures 3.2.3-1 and 3.2.3-2:

a. At least once per 24 hours,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and at least once per 12 hours when the reactor is operating with a LIMITING CONTROL ROD PATTERN for MCPR.

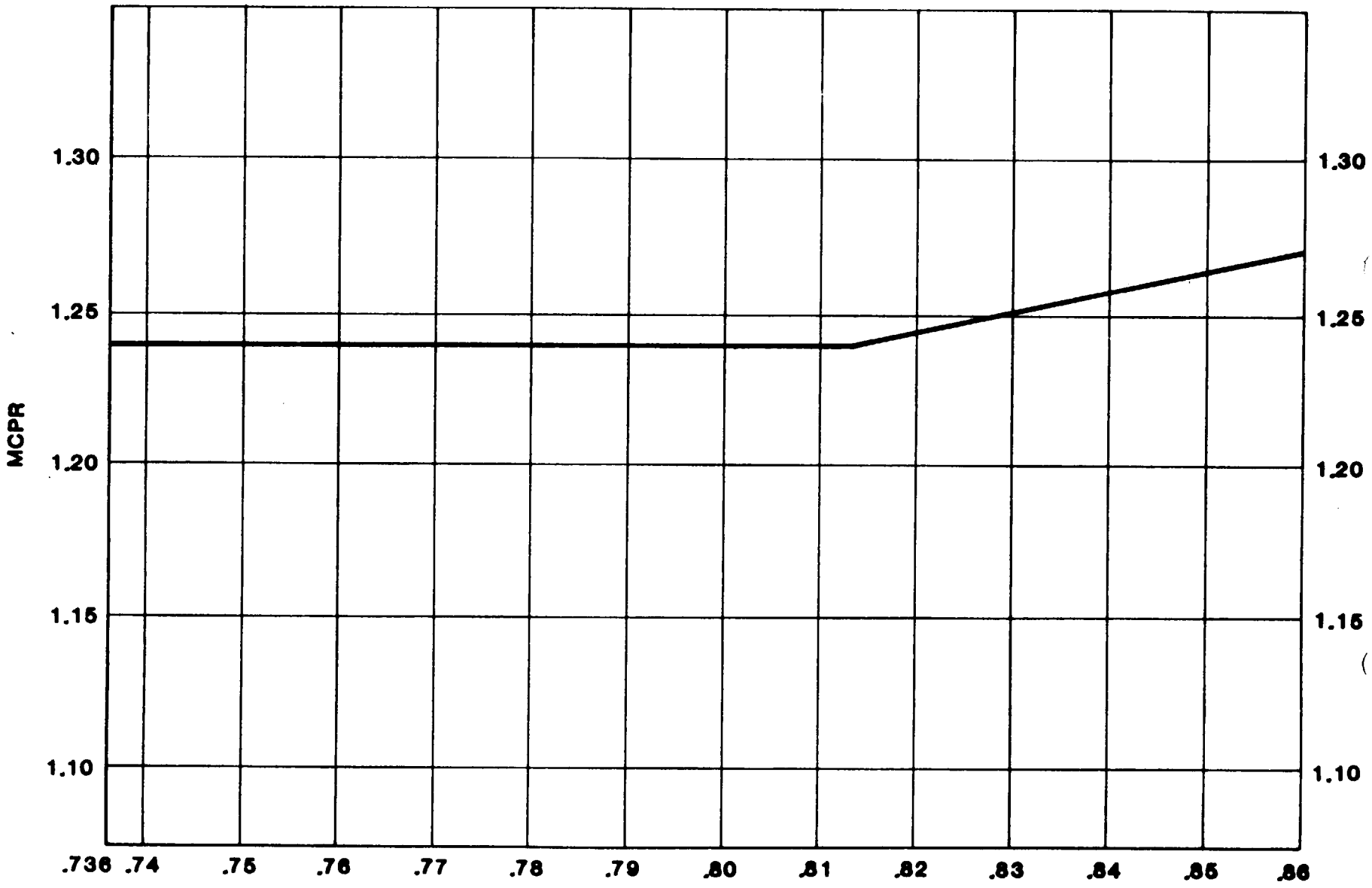

Figure 3.2.3-1 MINIMUM CRITICAL POWER RATIO (MCPR) VERSUS τ AT RATED FLOW

3/4.3 INSTRUMENTATION

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.1 As a minimum, the reactor protection system instrumentation channels shown in Table 3.3.1-1 shall be OPERABLE with the REACTOR PROTECTION SYSTEM RESPONSE TIME as shown in Table 3.3.1-2.

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

a. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system, place that trip system in the tripped condition* within 1 hour. The provisions of Specification 3.0.4 are not applicable.

b. With the the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for both trip systems, place at least one trip system** in the tripped condition within 1 hour and take the ACTION required by Table 3.3.1-1.

SURVEILLANCE REQUIREMENTS

4.3.1.1 Each reactor protection system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.1.1-1.

4.3.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed at least once per 18 months.

4.3.1.3 The REACTOR PROTECTION SYSTEM RESPONSE TIME of each reactor trip functional unit shown in Table 3.3.1-2 shall be demonstrated to be within its limit at least once per 18 months. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific reactor trip system.

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*With a design providing only one channel per trip system, an inoperable channel need not be placed in the tripped condition where this would cause the Trip Function to occur. In these cases, the inoperable channel shall be restored to OPERABLE status within 2 hours or the ACTION required by Table 3.3.1-1 for that Trip Function shall be taken.

**If more channels are inoperable in one trip system than in the other, select that trip system to place in the tripped condition, except when this would cause the Trip Function to occur.

REACTOR PROTECTION SYSTEM INSTRUMENTATION

ACTION

ACTION 1 - Be in at least HOT SHUTDOWN within 12 hours.

ACTION 2 - Verify all insertable control rods to be inserted in the core and lock the reactor mode switch in the Shutdown position within one hour.

ACTION 3 - Suspend all operations involving CORE ALTERATIONS* and insert all insertable control rods within one hour.

ACTION 4 - Be in at least STARTUP within 6 hours.

ACTION 5 - Be in STARTUP with the main steam line isolation valves closed within 6 hours or in at least HOT SHUTDOWN within 12 hours.

ACTION 6 - Initiate a reduction in THERMAL POWER within 15 minutes and reduce turbine first stage pressure to $\leq$ 140 psig, equivalent to THERMAL POWER less than 30% of RATED THERMAL POWER, within 2 hours.

ACTION 7 - Verify all insertable control rods to be inserted within 1 hour.

ACTION 8 - Lock the reactor mode switch in the Shutdown position within 1 hour.

ACTION 9 - Suspend all operations involving CORE ALTERATIONS,* and insert all insertable control rods and lock the reactor mode switch in the SHUTDOWN position within 1 hour.

*Except movement of IRM, SRM or special movable detectors, or replacement of LPRM strings provided SRM instrumentation is OPERABLE per Specification 3.9.2.

TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

TABLE NOTATIONS

(a) A channel may be placed in an inoperable status for up to 2 hours for required surveillance without placing the trip system in the tripped condition provided at least one OPERABLE channel in the same trip system is monitoring that parameter.

(b) The "shorting links" shall be removed from the RPS circuitry prior to and during the time any control rod is withdrawn* and during shutdown margin demonstrations performed per Specification 3.10.3.

(c) An APRM channel is inoperable if there are less than 2 LPRM inputs per level or less than 14 LPRM inputs to an APRM channel.

(d) This function is not required to be OPERABLE when the reactor pressure vessel head is unbolted or removed per Specification 3.10.1.

(e) This function shall be automatically bypassed when the reactor mode switch is not in the Run position.

(f) This function is not required to be OPERABLE when PRIMARY CONTAINMENT INTEGRITY is not required.

(g) Also actuates the standby gas treatment system.

(h) With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

(i) This function shall be automatically bypassed when turbine first stage pressure is $\leq$ 140 psig, equivalent to THERMAL POWER less than 30% of RATED THERMAL POWER.

(j) Also actuates the EOC-RPT system.

*Not required for control rods removed per Specifications 3.9.10.1 or 3.9.10.2.

TABLE 3.3.2-1

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
A. AUTOMATIC INITIATION				
1. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level				
(1) Low, Level 3	7	2	1, 2, 3	20
(2) Low Low, Level 2	1, 2, 3	2	1, 2, 3	20
b. Drywell Pressure - High	2, 7	2	1, 2, 3	20
c. Main Steam Line				
1) Radiation - High	1	2	1, 2, 3	21
	3	2	1, 2, 3	22
2) Pressure - Low	1	2	1	23
3) Flow - High	1	2/line(d)	1, 2, 3	21
d. Main Steam Line Tunnel Temperature - High	1	2	1, 2, 3	21
e. Main Steam Line Tunnel Δ Temperature - High	1	2	1(i), 2(i), 3(i)	21
f. Condenser Vacuum - Low	1	2	1, 2*, 3*	21
2. SECONDARY CONTAINMENT ISOLATION				
a. Reactor Building Vent Exhaust Plenum Radiation - High	4(c)(e)	2	1, 2, 3 and **	24
b. Drywell Pressure - High	4(c)(e)	2	1, 2, 3	24
c. Reactor Vessel Water Level - Low Low, Level 2	4(c)(e)	2	1, 2, 3, and #	24
d. Fuel Pool Vent Exhaust Radiation - High	4(c)(e)	2	1, 2, 3, and **	24

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

ACTION

ACTION 20 - Be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN with the next 24 hours.

ACTION 21 - Be in at least STARTUP with the associated isolation valves closed within 6 hours or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

ACTION 22 - Close the affected system isolation valves within 1 hour and declare the affected system inoperable.

ACTION 23 - Be in at least STARTUP within 6 hours.

ACTION 24 - Establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within 1 hour.

ACTION 25 - Lock the affected system isolation valves closed within 1 hour and declare the affected system inoperable.

ACTION 26 - Provided that the manual initiation function is OPERABLE for each other group valve, inboard or outboard, as applicable, in each line, restore the manual initiation function to OPERABLE status within 24 hours; otherwise, restore the manual initiation function to OPERABLE status within 8 hours; otherwise:

a. Be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours, or

b. Close the affected system isolation valves within the next hour and declare the affected system in operable.

NOTES

* May be bypassed with reactor steam pressure $\leq$ 1043 psig and all turbine stop valves closed.

** When handling irradiated fuel in the secondary containment and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

\# During CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

(a) See Specification 3.6.3, Table 3.6.3-1 for valves in each valve group.

(b) A channel may be placed in an inoperable status for up to 2 hours for required surveillance without placing the trip system in the tripped condition provided at least one other OPERABLE channel in the same trip system is monitoring that parameter.

(c) Also actuates the standby gas treatment system.

(d) A channel is OPERABLE if 2 of 4 instruments in that channel are OPERABLE.

(e) Also actuates secondary containment ventilation isolation dampers per Table 3.6.5.2-1.

(f) Closes only RWCU system inlet outboard valve.

(g) Requires RCIC steam supply pressure-low coincident with drywell pressure-high.

(h) Manual initiation isolates 1E51-F008 only and only with a coincident reactor vessel water level-low, level 3, signal.

(i) Both channels of each trip system may be placed in an inoperable status for up to 4 hours for required reactor building ventilation filter change and damper cycling without placing the trip system in the tripped condition provided that the ambient temperature channels in the same trip systems are operable.

TABLE 3.3.2-2

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
A. AUTOMATIC INITIATION		
1. PRIMARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level		
1) Low, Level 3	≥ 12.5 inches*	≥ 11.0 inches*
2) Low Low, Level 2	≥ -50 inches*	≥ -57 inches*
b. Drywell Pressure - High	≤ 1.69 psig	≤ 1.89 psig
c. Main Steam Line		
1) Radiation - High	≤ 3.0 x full power background	≤ 3.6 x full background
2) Pressure - Low	≥ 854 psig	≥ 834 psig
3) Flow - High	≤ 111 psid	≤ 116 psid
d. Main Steam Line Tunnel Temperature - High	≤ 140°F	≤ 146°F
e. Main Steam Line Tunnel Δ Temperature - High	≤ 36°F	≤ 42°F
f. Condenser Vacuum - Low	≥ 7 inches Hg vacuum	≥ 5.5 inches Hg vacuum
2. SECONDARY CONTAINMENT ISOLATION		
a. Reactor Building Vent Exhaust Plenum Radiation - High	≤ 10 mr/hr	≤ 15 mr/hr
b. Drywell Pressure - High	≤ 1.69 psig	≤ 1.89 psig
c. Reactor Vessel Water Level - Low Low, Level 2	≥ -50 inches*	≥ -57 inches*
d. Fuel Pool Vent Exhaust Radiation - High	≤ 10 mr/hr	≤ 15 mr/hr
3. REACTOR WATER CLEANUP SYSTEM ISOLATION		
a. ΔFlow - High	≤ 70 gpm	≤ 87.5 gpm
b. Heat Exchanger Area Temperature - High	≤ 181°F	≤ 187°F
c. Heat Exchanger Area Ventilation ΔT - High	≤ 85°F	≤ 91°F
d. Pump Area Temperature - High	≤ 116°F	≤ 122°F
e. Pump Area Ventilation ΔT - High	≤ 13°F	≤ 19°F
f. SLCS Initiation	NA	NA
g. Reactor Vessel Water Level - Low Low, Level 2	≥ -50 inches*	≥ -57 inches*

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
4. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION		
a. RCIC Steam Line Flow - High	≤ 290% of rated flow, 178" H_2O	≤ 295% of rated flow, 185" H_2O
b. RCIC Steam Supply Pressure - Low	≥ 57 psig	≥ 53 psig
c. RCIC Turbine Exhaust Diaphragm Pressure - High	≤ 10.0 psig	≤ 20.0 psig
d. RCIC Equipment Room Temperature - High	≤ 200°F	≤ 206°F
e. RCIC Steam Line Tunnel Temperature - High	≤ 200°F	≤ 206°F
f. RCIC Steam Line Tunnel Δ Temperature - High	≤ 117°F	≤ 123°F
g. Drywell Pressure - High	≤ 1.69 psig	≤ 1.89 psig
5. RHR SYSTEM STEAM CONDENSING MODE ISOLATION		
a. RHR Equipment Area Δ Temperature - High	≤ 50°F	≤ 56°F
b. RHR Area Cooler Temperature - High	≤ 200°F	≤ 206°F
c. RHR Heat Exchanger Steam Supply Flow - High	≤ 123" H_2O	≤ 128" H_2O

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
6. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION		
a. Reactor Vessel Water Level - Low, Level 3	≥ 12.5 inches*	≥ 11.0 inches*
b. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	≤ 135 psig**	≤ 145 psig**
c. RHR Pump Suction Flow - High	≤ 180" H_2O	≤ 186" H_2O
d. RHR Area Cooler Temperature - High	≤ 200°F	≤ 206°F
e. RHR Equipment Area ΔT - High	≤ 50°F	≤ 56°F
B. MANUAL INITIATION	Not Applicable	Not Applicable
1. Inboard Valves		
2. Outboard Valves		
3. Inboard Valves		
4. Outboard Valves		
5. Inboard Valves		
6. Outboard Valves		
7. Outboard Valve		

*See Bases Figure B 3/4 3-1.
**Corrected for cold water head with reactor vessel flooded.

TABLE 3.3.2-3

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
A. AUTOMATIC INITIATION	
1. PRIMARY CONTAINMENT ISOLATION	
a. Reactor Vessel Water Level	
1) Low, Level 3	NA
2) Low Low, Level 2	$\leq$ 1.0*/$\leq$ 13(a)**
b. Drywell Pressure - High	$\leq$ 13(a)
c. Main Steam Line	
1) Radiation - High(b)	$\leq$ 1.0*/$\leq$ 13(a)**
2) Pressure - Low	$\leq$ 1.0*/$\leq$ 13(a)**
3) Flow - High	$\leq$ 0.5*/$\leq$ 13(a)**
d. Main Steam Line Tunnel Temperature - High	NA
e. Condenser Vacuum - Low	NA
f. Main Steam Line Tunnel Δ Temperature - High	NA
2. SECONDARY CONTAINMENT ISOLATION	
a. Reactor Building Vent Exhaust Plenum Radiation - High(b)	$\leq$ 13(a)
b. Drywell Pressure - High	$\leq$ 13(a)
c. Reactor Vessel Water Level - Low, Level 2	$\leq$ 13(a)
d. Fuel Pool Vent Exhaust Radiation - High(b)	$\leq$ 13(a)
3. REACTOR WATER CLEANUP SYSTEM ISOLATION	
a. Δ Flow - High	$\leq$ 13(a)##
b. Heat Exchanger Area Temperature - High	NA
c. Heat Exchanger Area Ventilation ΔT-High	NA
d. Pump Area Temperature - High	NA
e. Pump Area Ventilation ΔT - High	NA
f. SLCS Initiation	NA
g. Reactor Vessel Water Level - Low Low, Level 2	$\leq$ 13(a)
4. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION	
a. RCIC Steam Line Flow - High	$\leq$ 13(a)###
b. RCIC Steam Supply Pressure - Low	$\leq$ 13(a)
c. RCIC Turbine Exhaust Diaphragm Pressure - High	NA
d. RCIC Equipment Room Temperature - High	NA
e. RCIC Steam Line Tunnel Temperature - High	NA
f. RCIC Steam Line Tunnel Δ Temperature - High	NA
g. Drywell Pressure - High	NA
5. RHR SYSTEM STEAM CONDENSING MODE ISOLATION	
a. RHR Equipment Area Δ Temperature - High	NA
b. RHR Area Cooler Temperature - High	NA
c. RHR Heat Exchanger Steam Supply Flow High	NA

TABLE 3.3.2-3 (Continued)

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
6. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION	
a. Reactor Vessel Water Level - Low, Level 3	≤ 13(a)
b. Reactor Vessel (RHR Cut-In Permissive) Pressure - High	N.A.
c. RHR Pump Suction Flow - High	N.A.
d. RHR Area Cooler Temperature High	N.A.
e. RHR Equipment Area ΔT High	N.A.
B. MANUAL INITIATION	N.A.
1. Inboard Valves	
2. Outboard Valves	
3. Inboard Valves	
4. Outboard Valves	
5. Inboard Valves	
6. Outboard Valves	
7. Outboard Valve	

(a) The isolation system instrumentation response time shall be measured and recorded as a part of the ISOLATION SYSTEM RESPONSE TIME. Isolation system instrumentation response time specified includes the delay for diesel generator starting assumed in the accident analysis.

(b) Radiation detectors are exempt from response time testing. Response time shall be measured from detector output or the input of the first electronic component in the channel.

* Isolation system instrumentation response time for MSIVs only. No diesel generator delays assumed.

** Isolation system instrumentation response time for associated valves except MSIVs.

\# Isolation system instrumentation response time specified for the Trip Function actuating each valve group shall be added to isolation time shown in Table 3.6.3-1 and 3.6.5.2-1 for valves in each valve group to obtain ISOLATION SYSTEM RESPONSE TIME for each valve.

\#\# Without 45±1 second time delay.

\#\#\# Without ≤ 5 second time delay.

N.A. Not Applicable.

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.4.2 The end-of-cycle recirculation pump trip (EOC-RPT) system instrumentation channels shown in Table 3.3.4.2-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.4.2-2 and with the END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME as shown in Table 3.3.4.2-3.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 30% of RATED THERMAL POWER.

ACTION:

a. With an end-of-cycle recirculation pump trip system instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.4.2-2, declare the channel inoperable until the channel is restored to OPERABLE status with the channel setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement for one or both trip systems, place the inoperable channel(s) in the tripped condition within 1 hour.

c. With the number of OPERABLE channels two or more less than required by the Minimum OPERABLE Channels per Trip System requirement(s) for one trip system and:

   1. If the inoperable channels consist of one turbine control valve channel and one turbine stop valve channel, place both inoperable channels in the tripped condition within 1 hour.

   2. If the inoperable channels include two turbine control valve channels or two turbine stop valve channels, declare the trip system inoperable.

d. With one trip system inoperable, restore the inoperable trip system to OPERABLE status within 72 hours or take the ACTION required by Specification 3.2.3.

e. With both trip systems inoperable, restore at least one trip system to OPERABLE status within 1 hour or take the ACTION required by Specification 3.2.3.

TABLE 3.3.4.2-1

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM[a]
1. Turbine Stop Valve - Closure	2[b]
2. Turbine Control Valve - Fast Closure	2[b]

[a] A trip system may be placed in an inoperable status for up to 2 hours for required surveillance provided that the other trip system is OPERABLE.

[b] This function shall be automatically bypassed when turbine first stage pressure is less than or equal to 140 psig, equivalent to THERMAL POWER less than 30% of RATED THERMAL POWER.

TABLE 3.3.6-2

CONTROL ROD WITHDRAWAL BLOCK INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE	
1. ROD BLOCK MONITOR			
a. Upscale			
1) Two Recirculation Loop Operation	≤ 0.66 W + 40%	≤ 0.66 W + 43%	18
2) Single Recirculation Loop Operation	≤ 0.66W + 34.7%	≤ 0.66W + 37.7%	
b. Inoperative	N.A.	N.A.	
c. Downscale	≥ 5% of RATED THERMAL POWER	≥ 3% of RATED THERMAL POWER	
2. APRM			
a. Flow Biased Simulated Thermal Power-Upscale			
1) Two Recirculation Loop Operation	≤ 0.66 W + 42%*	≤ 0.66 W + 45%*	18
2) Single Recirculation Loop Operation	≤ 0.66W + 36.7%	≤ 0.66W + 39.7%*	
b. Inoperative	N.A.	N.A.	
c. Downscale	≥ 5% of RATED THERMAL POWER	≥ 3% of RATED THERMAL POWER	
d. Neutron Flux-High	≤ 12% of RATED THERMAL POWER	≤ 14% of RATED THERMAL POWER	
3. SOURCE RANGE MONITORS			
a. Detector not full in	N.A.	N.A.	18
b. Upscale	≤ 2 x 10^5 cps	≤ 5 x 10^5 cps	
c. Inoperative	N.A.	N.A.	18
d. Downscale	≥ 0.7 cps	≥ 0.5 cps	
4. INTERMEDIATE RANGE MONITORS			2
a. Detector not full in	N.A.	N.A.	18
b. Upscale	≤ 108/125 of full scale	≤ 110/125 of full scale	
c. Inoperative	N.A.	N.A.	18
d. Downscale	≥ 5/125of full scale	≥ 3/125 of full scale	

TABLE 3.3.6-2 (Continued)

CONTROL ROD WITHDRAWAL BLOCK INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
5. SCRAM DISCHARGE VOLUME		
a. Water Level-High	≤ 765' 5¼"	≤ 765' 5¼"
b. Scram Discharge Volume Switch in Bypass	N.A.	N.A.
6. REACTOR COOLANT SYSTEM RECIRCULATION FLOW		
a. Upscale	≤ 108/125 of full scale	≤ 111/125 of full scale
b. Inoperative	N.A.	N.A.
c. Comparator	≤ 10% flow deviation	≤ 11% flow deviation

*The Average Power Range Monitor rod block function is varied as a function of recirculation loop flow (W). The trip setting of this function must be maintained in accordance with Specification 3.2.2.

TABLE 4.3.6-1

CONTROL ROD WITHDRAWAL BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION[a]	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. ROD BLOCK MONITOR				
a. Upscale	NA	S/U[b][c],M[c]	Q	1*
b. Inoperative	NA	S/U[b][c],M[c]	N.A.	1*
c. Downscale	NA	S/U[b][c],M[c]	Q	1*
2. APRM				
a. Flow Biased Simulated Thermal Power-Upscale	NA	S/U[b],M	SA	1
b. Inoperative	NA	S/U[b],M	N.A.	1, 2, 5
c. Downscale	NA	S/U[b],M	SA	1
d. Neutron Flux-High	NA	S/U[b],M	SA	2, 5
3. SOURCE RANGE MONITORS				
a. Detector not full in	NA	S/U[b],W	N.A.	2, 5
b. Upscale	NA	S/U[b],W	Q	2, 5
c. Inoperative	NA	S/U[b],W	N.A.	2, 5
d. Downscale	NA	S/U[b],W	Q	2, 5
4. INTERMEDIATE RANGE MONITORS				
a. Detector not full in	NA	S/U[b],W	N.A.	2, 5
b. Upscale	NA	S/U[b],W	Q	2, 5
c. Inoperative	NA	S/U[b],W	N.A.	2, 5
d. Downscale	NA	S/U[b],W	Q	2, 5
5. SCRAM DISCHARGE VOLUME				
a. Water Level-High	NA	Q	R	1, 2, 5**
b. Scram Discharge Volume Switch in Bypass	NA	M	N.A.	5**
6. REACTOR COOLANT SYSTEM RECIRCULATION FLOW				
a. Upscale	NA	S/U[b],M	Q	1
b. Inoperative	NA	S/U[b],M	N.A.	1
c. Comparator	NA	S/U[b],M	Q	1

TABLE 3.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION

ACTION

ACTION 70 -

a. With one of the required monitors inoperable, place the inoperable channel in the downscale tripped condition within 1 hour; restore the inoperable channel to OPERABLE status within 7 days, or, within the next 6 hours, initiate and maintain operation of the control room emergency filtration system in the pressurization mode of operation.

b. With both of the required monitors inoperable, initiate and maintain operation of the control room emergency filtration system in the pressurization mode of operation within 1 hour.

SEISMIC MONITORING INSTRUMENTATION*

LIMITING CONDITION FOR OPERATION

3.3.7.2 The seismic monitoring instrumentation shown in Table 3.3.7.2-1 shall be OPERABLE.**

APPLICABILITY: At all times.

ACTION:

a. With one or more seismic monitoring instruments inoperable for more than 30 days, in lieu of any other report required by Specification 6.6.B, prepare and submit a Special Report to the Commission pursuant to Specification 6.6.C within the next 10 days outlining the cause of the malfunction and the plans for restoring the instrument(s) to OPERABLE status.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.7.2.1 Each of the above required seismic monitoring instruments shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.7.2-1.

4.3.7.2.2 Each of the above required seismic monitoring instruments actuated during a seismic event greater than or equal to 0.02g shall be restored to OPERABLE status within 24 hours and a CHANNEL CALIBRATION performed within 5 days following the seismic event. Data shall be retrieved from actuated instruments and analyzed to determine the magnitude of the vibratory ground motion. In lieu of any other report required by Specification 6.6.B, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.6.C within 10 days describing the magnitude, frequency spectrum and resultant effect upon unit features important to safety.

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*The Seismic Monitoring Instrumentation System is shared between La Salle Unit 1 and La Salle Unit 2.

**The normal or emergency power source may be inoperable in OPERATIONAL CONDITION 4 or 5 or when defueled.

METEOROLOGICAL MONITORING INSTRUMENTATION*

LIMITING CONDITION FOR OPERATION

3.3.7.3 The meteorological monitoring instrumentation channels shown in Table 3.3.7.3-1 shall be OPERABLE.**

APPLICABILITY: At all times.

ACTION:

a. With one or more meteorological monitoring instrumentation channels inoperable for more than 7 days, in lieu of any other report required by Specification 6.6.B, prepare and submit a Special Report to the Commission pursuant to Specification 6.6.C within the next 10 days outlining the cause of the malfunction and the plans for restoring the instrumentation to OPERABLE status.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.7.3 Each of the above required meteorological monitoring instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.7.3-1.

---

*The Meteorological Monitoring Instrumentation System is shared between La Salle Unit 1 and La Salle Unit 2.

**The normal or emergency power source may be inoperable in OPERATIONAL CONDITION 4 or 5 or when defueled.

TABLE 3.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION

		REQUIRED NUMBER OF CHANNELS	MINIMUM CHANNELS OPERABLE
1.	Reactor Vessel Pressure	2	1
2.	Reactor Vessel Water Level	2	1
3.	Suppression Chamber Water Level	2	1
4.	Suppression Chamber Water Temperature	7, 1/well	7, 1/well
5.	Suppression Chamber Air Temperature	2	1
6.	Drywell Pressure	2	1
7.	Drywell Air Temperature	2	1
8.	Drywell Oxygen Concentration*	2	1
9.	Drywell Hydrogen Concentration Analyzer* and Monitor	2	1
10.	Primary Containment Gross Gamma Radiation	2	1
11.	Safety/Relief Valve Position Indicators	1/valve	1/valve
12.	Noble Gas Monitor, Main Stack	1	1
13.	Noble Gas Monitor, Standby Gas Treatment System Stack	1	1

*Actuated after LOCA.

SOURCE RANGE MONITORS

LIMITING CONDITION FOR OPERATION

3.3.7.6 At least three source range monitor channels shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 2*, 3, and 4.

ACTION:

a. In OPERATIONAL CONDITION 2* with one of the above required source range monitor channels inoperable, restore at least three source range monitor channels to OPERABLE status within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours.

b. In OPERATIONAL CONDITION 3 or 4 with two or more of the above required source range monitor channels inoperable, verify all insertable control rods to be inserted in the core and lock the reactor mode switch in the Shutdown position within 1 hour.

SURVEILLANCE REQUIREMENTS

4.3.7.6 Each of the above required source range monitor channels shall be demonstrated OPERABLE by:

a. Performance of a:

1. CHANNEL CHECK at least once per:

a) 12 hours in CONDITION 2*, and

b) 24 hours in CONDITION 3 or 4.

2. CHANNEL CALIBRATION** at least once per 18 months.

b. Performance of a CHANNEL FUNCTIONAL TEST:

1. Within 24 hours prior to moving the reactor mode switch from the Shutdown position, if not performed within the previous 7 days, and

2. At least once per 31 days.

c. Verifying, prior to withdrawal of control rods, that the SRM count rate is at least 0.7 cps# with the detector fully inserted.

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*With IRM's on range 2 or below.
**Neutron detectors may be excluded from CHANNEL CALIBRATION.
#Provided signal-to-noise ration is $\geq$2. Otherwise, 3 cps.

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.10 The radioactive liquid effluent monitoring instrumentation channels shown in Table 3.3.7.10-1 shall be OPERABLE with their alarm/trip setpoints set to ensure that the limits of Specification 3.11.1.1 are not exceeded. The alarm trip setpoints of these channels shall be determined in accordance with the Offsite Dose Calculation Manual (ODCM).

APPLICABILITY: At all times.

ACTION:

a. With a radioactive liquid effluent monitoring instrumentation channel alarm/trip setpoint less conservative than required, immediately suspend the release of radioactive liquid effluents monitored by the affected channel or declare the channel inoperable.

b. With less than the minimum number of radioactive liquid effluent monitoring instrumentation channels OPERABLE, take the ACTION shown in Table 3.3.7.10-1. Restore the inoperable instrumentation to OPERABLE status within the time specified in the ACTION or, in lieu of a Licensee Event Report, explain in the next Semiannual Radioactive Effluent Release Report why this inoperability was not corrected within the time specified.

c. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.7.10 Each radioactive liquid effluent monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK, SOURCE CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.7.10-1.

TABLE 3.3.7.10-1

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	ACTION
1. GAMMA SCINTILLATION MONITOR PROVIDING ALARM AND AUTOMATIC TERMINATION OF RELEASE		
a. Liquid Radwaste Effluent Line	1	100
2. GAMMA SCINTILLATION MONITORS PROVIDING ALARM BUT NOT PROVIDING AUTOMATIC TERMINATION OF RELEASE		
a. Service Water System Effluent Line (Unit 1)	1	101
b. RHR Service Water (Line A) Effluent Line	1	101
c. RHR Service Water (Line B) Effluent Line	1	101
d. Service Water System Effluent Line (Unit 2)	1	101
3. FLOW RATE MEASUREMENT DEVICES		
a. Liquid Radwaste Effluent Line	1	102
b. River Discharge - Blowdown Pipe	1	102

TABLE 3.3.7.10-1 (Continued)

TABLE NOTATION

ACTION 100 - With the number of OPERABLE channels 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 4.11.1.1.3, 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 at a limit of detection of at least 10-7 microcurie/ml or gamma spectrometric analysis.

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 for Instrument 3a, or for known valve positions for Instrument 3b, may be used to estimate flow.

TABLE 4.3.7.10-1

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
1. GAMMA SCINTILLATION MONITOR PROVIDING ALARM AND AUTOMATIC TERMINATION OF RELEASE				
a. Liquid Radwaste Effluents Line	D	P	Q(1)	R(3)
2. GAMMA SCINTILLATION MONITORS PROVIDING ALARM BUT NOT PROVIDING AUTOMATIC TERMINATION OF RELEASE				
a. Service Water System Effluent Line (Unit 1)	D	M	Q(2)	R(3)
b. RHR Service Water (Line A) Effluent Line	D	M	Q(2)	R(3)
c. RHR Service Water (Line B) Effluent Line	D	M	Q(2)	R(3)
d. Service Water System Effluent Line (Unit 2)	D	M	Q(2)	R(3)
3. FLOW RATE MEASUREMENT DEVICES				
a. Liquid Radwaste Effluent Line	D(4)	N.A.	Q	R
b. River Discharge - Blowdown Pipe	D(4)	N.A.	Q	R

TABLE 4.3.7.11-1 (Continued)

TABLE NOTATION

* At all times.

** During main condenser offgas treatment system operation.

\# During operation of the main condenser air ejector.

\#\# During operation of the SBGTS.

(1) The CHANNEL FUNCTIONAL TEST shall also demonstrate the automatic isolation capability of this pathway, and that control room alarm annunciation occurs if any of the following conditions exists: (each channel will be tested independently so as not to initiate automatic isolation during operation).

1. Instrument indicates measured levels above the alarm/trip setpoint.
2. Loss of power.
3. Instrument alarms on downscale failure.
4. Instrument controls not set in Operate or High Voltage mode. (Automatic isolation shall be demonstrated during the CHANNEL CALIBRATION.)

(2) The CHANNEL FUNCTIONAL TEST for the log scale monitor shall also demonstrate that control room alarm annunciation occurs if any of the following conditions exists:

1. Instrument indicates measured levels above the alarm setpoint.
2. Loss of power.
3. Instrument alarms on downscale failure.
4. Instrument controls not set in Operate or High Voltage mode.

(3) The initial CHANNEL CALIBRATION shall be performed using one or more of the reference radioactive standards certified by the National Bureau of Standards (NBS) or using standards that have been obtained from suppliers that participate in measurement assurance activities with NBS. These standards shall permit calibrating the system over its intended range of energy and measurement range. For subsequent CHANNEL CALIBRATION, the initial reference radioactive standards or radioactive sources that have been related to the initial calibration shall be used.

(4) The CHANNEL CALIBRATION shall include the use of standard gas samples containing a nominal:

1. One volume percent hydrogen, balance nitrogen, and
2. Four volume percent hydrogen, balance nitrogen.

(5) The CHANNEL FUNCTIONAL TEST shall also demonstrate that control room alarm annunciation occurs if any of the following conditions exists:

1. Instrument indicates measured levels above the alarm setpoint.
2. Circuit failure.
3. Instrument controls not set in the Operate mode.

3/4.4 REACTOR COOLANT SYSTEM

3/4.4.1 RECIRCULATION SYSTEM

RECIRCULATION LOOPS

LIMITING CONDITION FOR OPERATION

3.4.1.1 Two reactor coolant system recirculation loops shall be in operation.

APPLICABILITY: OPERATIONAL CONDITIONS 1* and 2*.

ACTION:

a. With one reactor coolant system recirculation loop not in operation:

1. Within 4 hours:

a) Place the recirculation flow control system in the Master Manual mode, and

b) Reduce THERMAL POWER to $\leq$ 50% of RATED THERMAL POWER, and,

c) Increase the MINIMUM CRITICAL POWER RATIO (MCPR) Safety Limit by 0.01 to 1.07 per Specification 2.1.2, and,

d) Increase the MINIMUM CRITICAL POWER RATIO (MCPR) Limiting Condition for Operation by 0.01 per Specification 3.2.3, and,

e) Reduce the MAXIMUM AVERAGE PLANAR LINEAR HEAT GENERATION RATE (MAPLHGR) limit to a value of 0.85 times the two recirculation loop operation limit per Specification 3.2.1, and,

f) Reduce the Average Power Range Monitor (APRM) Scram and Rod Block and Rod Block Monitor Trip Setpoints and Allowable Values to those applicable to single loop recirculation loop operation per Specifications 2.2.1, 3.2.2, and 3.3.6.

2. At least once per 12 hours:

a) Verify that the APRM flux noise averaged over 30 minutes does not exceed 5% peak to peak; otherwise, reduce the recirculation loop flow until the APRM flux noise is less than the 5% peak to peak limit, and,

b) Verify that the core plate ΔP noise does not exceed 1 psi peak to peak; otherwise, reduce the recirculation loop flow until the ΔP noise is less than the 1 psi limit.

*See Special Test Exception 3.10.4.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

3. The provisions of Specification 3.0.4 are not applicable.

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

b. With no reactor coolant system recirculation loops in operation, immediately initiate measures to place the unit in at least HOT SHUTDOWN within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.4.1.1 Each reactor coolant system recirculation loop flow control valve shall be demonstrated OPERABLE at least once per 18 months by:

a. Verifying that the control valve fails "as is" on loss of hydraulic pressure at the hydraulic power units, and

b. Verifying that the average rate of control valve movement is:

1. Less than or equal to 11% of stroke per second opening, and

2. Less than or equal to 11% of stroke per second closing.

JET PUMPS

LIMITING CONDITION FOR OPERATION

3.4.1.2 All jet pumps shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one or more jet pumps inoperable, be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.4.1.2.1 Each of the above required jet pumps shall be demonstrated OPERABLE prior to the THERMAL POWER exceeding 25% of RATED THERMAL POWER and at least once per 24 hours by measuring and recording each of the below specified parameters and verifying that no two of the following conditions occur when both recirculation loops are operating at the same flow control valve position.

a. The indicated recirculation loop flow differs by more than 10% from the established flow control valve position-loop flow characteristics for two recirculation loop operation.

b. The indicated total core flow differs by more than 10% from the established total core flow value derived from either the:

   1. Established THERMAL POWER-core flow relationship, or

   2. Established core plate diffetential pressure-core flow relationship for two recirculation loop operation.

c. The indicated diffuser-to-lower plenum differential pressure of any individual jet pump differs from established two recirculation loop operation patterns by more than 10%.

4.4.1.2.2 During single recirculation loop operation, each of the above required jet pumps shall be demonstrated OPERABLE at least once per 24 hours by verifying that no two of the following conditions occur:

a. The indicated recirculation loop flow in the operating loop differs by more that 10% from the established single recirculation flow control valve position-loop flow characteristics.

b. The indicated total core flow differs by more than 10% from the established total core flow value from single recirculation loop flow measurements.

c. The indicated diffuser-to-lower plenum differential pressure of any individual jet pump differs from established single recirculation loop operational patterns by more than 10%.

RECIRCULATION LOOP FLOW

LIMITING CONDITION FOR OPERATION

3.4.1.3 Recirculation loop flow mismatch shall be maintained within:

a. 5% of rated recirculation flow with core flow greater than or equal to 70% of rated core flow.

b. 10% of rated recirculation flow with core flow less than 70% of rated core flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2 during two recirculation loop operation.

ACTION:

With recirculation loop flows different by more than the specified limits, either:

a. Restore the recirculation loop flows to within the specified limit within 2 hours, or

b. Declare the recirculation loop with the lower flow not in operation and take the ACTION require by Specification 3.4.1.1.

SURVEILLANCE REQUIREMENTS

4.4.1.3 Recirculation loop flows shall be verified to be within the limits at least once per 24 hours.

3/4.4.2 SAFETY/RELIEF VALVES

LIMITING CONDITION FOR OPERATION

3.4.2 The safety valve function of eighteen reactor coolant system safety/relief valves shall be OPERABLE with the specified code safety valve function lift settings.*#

a. 4 safety/relief valves @ 1205 psig + 1%
b. 4 safety/relief valves @ 1195 psig + 1%
c. 4 safety/relief valves @ 1185 psig + 1%
d. 4 safety/relief valves @ 1175 psig + 1%
e. 2 safety/relief valves @ 1146 psig + 1%

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With the safety valve function of one or more of the above required safety/relief valves inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. With one or more safety/relief valves stuck open, provided that suppression pool average water temperature is less than 110°F, close the stuck open relief valve(s); if unable to close the open valve(s) within 2 minutes or if suppression pool average water temperature is 110°F or greater, place the reactor mode switch in the Shutdown position.

c. With one or more safety/relief valve stem position indicators inoperable, restore the inoperable stem position indicators to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.4.2.1 The safety/relief valve stem position indicators of each safety/relief valve shall be demonstrated OPERABLE by performance of a:

a. CHANNEL CHECK at least once per 31 days, and a
b. CHANNEL CALIBRATION at least once per 18 months.**

4.4.2.2 The low low set function shall be demonstrated not to interfere with the OPERABILITY of the safety relief valves or the ADS by performance of a CHANNEL CALIBRATION at least once per 18 months.

*The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures.

#Up to two inoperable valves may be replaced with spare OPERABLE valves with lower setpoints until the next refueling outage.

**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.

OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.3.2 Reactor coolant system leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE.

b. 5 gpm UNIDENTIFIED LEAKAGE.

c. 25 gpm total leakage averaged over any 24 hour period.

d. 1 gpm leakage at a reactor coolant system pressure at 1000 ± 50 psig from any reactor coolant system pressure isolation valve specified in Table 3.4.3.2-1.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. With any reactor coolant system leakage greater than the limits in b and/or c, above, reduce the leakage rate to within the limits within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With any reactor coolant system pressure isolation valve leakage greater than the above limit, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least two closed valves, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

d. With one or more high/low pressure interface valve leakage pressure monitors inoperable, restore the inoperable monitor(s) to OPERABLE status within 7 days or verify the pressure to be less than the alarm setpoint at least once per 12 hours by local indication; restore the inoperable monitor(s) to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 12 hours.

SURVEILLANCE REQUIREMENTS

4.4.3.2.1 The reactor coolant system leakage shall be demonstrated to be within each of the above limits by:

a. Monitoring the primary containment atmospheric particulate and gaseous radioactivity at least once per 12 hours,

b. Monitoring the primary containment sump flow rate at least once per 12 hours, and

c. Monitoring the primary containment air coolers condensate flow rate at least once per 12 hours.

3/4.4.5 SPECIFIC ACTIVITY

LIMITING CONDITION FOR OPERATION

3.4.5 The specific activity of the primary coolant shall be limited to:

a. Less than or equal to 0.2 microcurie per gram DOSE EQUIVALENT I-131, and

b. Less than or equal to 100/$\bar{E}$ microcuries per gram.

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

ACTION:

a. In OPERATIONAL CONDITIONS 1, 2 or 3 with the specific activity of the primary coolant;

1. Greater than 0.2 microcuries per gram DOSE EQUIVALENT I-131 but less than or equal to 4.0 microcuries per gram, operation may continue for up to 48 hours provided that the cumulative operating time under these circumstances does not exceed 800 hours in any consecutive 12 month period. With the total cumulative operating time at a primary coolant specific activity greater than or equal to 0.2 microcurie per gram DOSE EQUIVALENT I-131 exceeding 500 hours in any consecutive six month period, prepare and submit a special report to the Commission pursuant to Specification 6.6.C within 30 days indicating the number of hours of operation above this limit. The provisions of Specification 3.0.4 are not applicable.

2. Greater than 0.2 microcuries per gram DOSE EQUIVALENT I-131 for more than 48 hours during one continuous time interval or for more than 800 hours cumulative operating time in a consecutive 12-month period, or greater than or equal to 4 microcuries per gram, be in at least HOT SHUTDOWN with the main steam line isolation valves closed within 12 hours.

3. Greater than 100/$\bar{E}$ microcuries per gram, be in at least HOT SHUTDOWN with the main steamline isolation valves closed within 12 hours.

b. In OPERATIONAL CONDITIONS 1, 2, 3 or 4, with the specific activity of the primary coolant greater than 0.2 microcurie per gram DOSE EQUIVALENT I-131 or greater than 100 $\bar{E}$ microcuries per gram, perform the sampling and analysis requirements of Item 4a of Table 4.4.5-1 until the specific activity of the primary coolant is restored to within the limit. A REPORTABLE OCCURRENCE shall be prepared and submitted to the Commission pursuant to Specification 6.6.B. This report shall contain the results of the specific activity analyses and the time duration when the specific activity of the coolant exceeded 0.2 microcurie per gram DOSE EQUIVALENT I-131 together with the following additional information.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION (Continued)

c. In OPERATIONAL CONDITION 1 or 2, with:

1. THERMAL POWER changed by more than 15% of RATED THERMAL POWER in 1 hour*, or

2. The off-gas level, prior to the holdup line, increased by more than 25,000 microcuries per second in one hour during steady state operation at release rates less than 100,000 microcuries per second, or

3. The off-gas level, prior to the holdup line, increased by more than 15% in 1 hour during steady state operation at release rates greater than 100,000 microcuries per second,

perform the sampling and analysis requirements of Item 4b of Table 4.4.5-1 until the specific activity of the primary coolant is restored to within its limit. Prepare and submit to the Commission a Special Report pursuant to Specification 6.6.C at least once per 92 days containing the results of the specific activity analysis together with the below additional information for each occurrence.

Additional Information

1. Reactor power history starting 48 hours prior to:
   a) The first sample in which the limit was exceeded, and/or
   b) The THERMAL POWER or off-gas level change.
2. Fuel burnup by core region.
3. Clean-up flow history starting 48 hours prior to:
   a) The first sample in which the limit was exceeded, and/or
   b) The THERMAL POWER or off-gas level change.
4. Off-gas level starting 48 hours prior to:
   a) The first sample in which the limit was exceeded, and/or
   b) The THERMAL POWER or off-gas level change.

SURVEILLANCE REQUIREMENTS

4.4.5 The specific activity of the reactor coolant shall be demonstrated to be within the limits by performance of the sampling and analysis program of Table 4.4.5-1.

*Not applicable during the Startup Test Program.

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.

4.4.6.1.3 The reactor vessel material specimens shall be removed and examined to determine reactor pressure vessel fluence as a function of time and THERMAL POWER 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 fluence determinations shall be used to update the curves of Figure 3.4.6.1-1.

4.4.6.1.4 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 the reactor coolant temperature is:

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

   2. $\leq$ 85°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.

Table 4.4.6.1.3-1

Reactor Vessel Material Surveillance Program Withdrawal Schedule

Specimen holder	Vessel location	Lead factor	Withdrawal time (Effective Full Power Years)
117C4936G010	300°	0.6	6
117C4936G011	120°	0.6	15
117C4936G012	30°	0.6	Spare
Neutron Dosimeter	30°		1st Refuel Outage

3/4.4.9 RESIDUAL HEAT REMOVAL

HOT SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.9.1 Two# shutdown cooling mode loops of the residual heat removal (RHR) system shall be OPERABLE and at least one shutdown cooling mode loop shall be in operation* ## with each loop consisting of at least:

a. One OPERABLE RHR pump, and

b. One OPERABLE RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITION 3, with reactor vessel pressure less than the RHR cut-in permissive setpoint.

ACTION:

a. With less than the above required RHR shutdown cooling mode loops OPERABLE, immediately initiate corrective action to return the required loops to OPERABLE status as soon as possible. Within 1 hour and at least once per 24 hours thereafter, demonstrate the operability of at least one alternate method capable of decay heat removal for each inoperable RHR shutdown cooling mode loop. Be in at least COLD SHUTDOWN within 24 hours.**

b. With no RHR shutdown cooling mode loop in operation, immediately initiate corrective action to return at least one loop to operation as soon as possible. Within 1 hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature and pressure at least once per hour.

SURVEILLANCE REQUIREMENTS

4.4.9.1 At least one shutdown cooling mode loop of the residual heat removal system or alternate method shall be determined to be in operation and circulating reactor coolant at least once per 12 hours.

#One RHR shutdown cooling mode loop may be inoperable for up to 2 hours for surveillance testing provided the other loop is OPERABLE and in operation.

*The shutdown cooling pump may be removed from operation for up to 2 hours per 8 hour period provided the other loop is OPERABLE.

##The RHR shutdown cooling mode loop may be removed from operation during hydrostatic testing.

**Whenever two or more RHR subsystems are inoperable, if unable to attain COLD SHUTDOWN as required by this ACTION, maintain reactor coolant temperature as low as practical by use of alternate heat removal methods.

COLD SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.9.2 Two# shutdown cooling mode loops of the residual heat removal (RHR) system shall be OPERABLE* and at least one shutdown cooling mode loop shall be in operation** ## with each loop consisting of at least:

a. One OPERABLE RHR pump, and

b. One OPERABLE RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITION 4.

ACTION:

a. With less than the above required RHR shutdown cooling mode loops OPERABLE, within 1 hour and at least once per 24 hours thereafter, demonstrate the operability of at least one alternate method capable of decay heat removal for each inoperable RHR shutdown cooling mode loop.

b. With no RHR shutdown cooling mode loop in operation, within 1 hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature and pressure at least once per hour.

SURVEILLANCE REQUIREMENTS

4.4.9.2 At least one shutdown cooling mode loop of the residual heat removal system or alternate method shall be determined to be in operation and circulating reactor coolant at least once per 12 hours.

#One RHR shutdown cooling mode loop may be inoperable for up to 2 hours for surveillance testing provided the other loop is OPERABLE and in operation.

*The normal or emergency power source may be inoperable.

**The shutdown cooling pump may be removed from operation for up to 2 hours per 8 hour period provided the other loop is OPERABLE.

##The shutdown cooling mode loop may be removed from operation during hydrostatic testing.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

d. For ECCS divisions 1 and 2, provided that ECCS division 3 is OPERABLE:

1. With LPCI subsystem "A" and either LPCI subsystem "B" or "C" inoperable, restore at least the inoperable LPCI subsystem "A" or inoperable LPCI subsystem "B" or "C" to OPERABLE status within 72 hours.

2. With the LPCS system inoperable and either LPCI subsystems "B" or "C" inoperable, restore at least the inoperable LPCS system or inoperable LPCI subsystem "B" or "C" to OPERABLE status within 72 hours.

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

e. For ECCS divisions 1 and 2, provided that ECCS division 3 is OPERABLE and divisions 1 and 2 are otherwise OPERABLE:

1. With one of the above required ADS valves inoperable, 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 $\leq$ 122 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 $<$ 122 psig within the next 24 hours.

f. With an ECCS discharge line "keep filled" pressure alarm instrumentation channel inoperable, perform Surveillance Requirement 4.5.1.a.1 at least once per 24 hours.

g. With an ECCS header delta P instrumentation channel inoperable, restore the inoperable channel to OPERABLE status within 72 hours or determine ECCS header delta P locally at least once per 12 hours; otherwise, declare the associated ECCS inoperable.

h. With Surveillance Requirement 4.5.1.d.2 not performed at the required interval due to low reactor steam 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.

i. 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 6.6.C within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date. The current value of the usage factor for each affected safety injection nozzle shall be provided in this Special Report whenever its value exceeds 0.70.

j. With one or more ECCS corner room watertight doors inoperable, restore all the inoperable ECCS corner room watertight doors to OPERABLE status within 14 days, otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

*Whenever two or more RHR subsystems are inoperable, if unable to attain COLD SHUTDOWN as required by this ACTION, maintain reactor coolant temperature as low as practical by use of alternate heat removal methods.

SURVEILLANCE REQUIREMENTS

4.5.1 ECCS divisions 1, 2 and 3 shall be demonstrated OPERABLE by:

a. At least once per 31 days for the LPCS, LPCI and HPCS systems:

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. Performance of a CHANNEL FUNCTIONAL TEST of the:

a) Discharge line "keep filled" pressure alarm instrumentation, and

b) Header delta P instrumentation.

3. 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.

4. Verifying that each ECCS corner room watertight door is closed, except during normal entry and exit from the room.

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

1. LPCS pump develops a flow of at least 6350 gpm against a test line pressure greater than or equal to 290 psig.

2. LPCI pump develops a flow of at least 7200 gpm against a test line pressure greater than or equal to 130 psig.

3. HPCS pump develops a flow of at least 6250 gpm against a test line pressure greater than or equal to 370 psig.

c. For the LPCS, LPCI and HPCS systems, at least once per 18 months:

1. 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.

2. Performing a CHANNEL CALIBRATION of the:

a) Discharge line "keep filled" pressure alarm instrumentation and verifying the:

1) High pressure setpoint and the low pressure setpoint of the:

(a) LPCS system to be ≤ 500 psig and ≥ 55 psig, respectively.

(b) LPCI subsystems to be ≤ 400 psig and ≥ 55 psig, respectively.

2) Low pressure setpoint of the HPCS system to be ≥ 63 psig.

b) Header delta P instrumentation and verifying the setpoint of the:

1) LPCS system and LPCI subsystems to be ± 1 psid.

2) HPCS system to be between 5 ± 2.0 psid greater than the normal indicated ΔP.

3. Verifying that the suction for the HPCS system is automatically transferred from the condensate storage tank to the suppression chamber on a condensate storage tank low water level signal and on a suppression chamber high water level signal.

4. Visually inspecting the ECCS corner room watertight door seals and room penetration seals and verifying no abnormal degradation, damage, or obstructions.

d. For the ADS by:

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 and observing the expected change in the indicated valve position.

c) Performing a CHANNEL CALIBRATION of the accumulator backup compressed gas system low pressure alarm system and verifying an alarm setpoint of 500 + 40, - 0 psig on decreasing pressure.

3/4.5.3 SUPPRESSION CHAMBER#

LIMITING CONDITION FOR OPERATION

3.5.3 The suppression chamber shall be OPERABLE:

a. In OPERATIONAL CONDITION 1, 2 or 3 with a contained water volume of at least 128,800 ft^3, equivalent to a level of 26 ft 2½ in.

b. In OPERATIONAL CONDITION 4 or 5* with a contained water volume of at least 70,000 ft^3, equivalent to a level of 14 ft 0 in, except that the suppression chamber level may be less than the limit or may be drained in OPERATIONAL CONDITION 4 or 5* provided that:

1. No operations are performed that have a potential for draining the reactor vessel,

2. The reactor mode switch is locked in the Shutdown or Refuel position,

3. The condensate storage tank contains at least 135,000 available gallons of water, equivalent to a level of 14.5 feet, and

4. The HPCS system is OPERABLE per Specification 3.5.2 with an OPERABLE flow path capable of taking suction from the condensate storage tank and transferring the water through the spray sparger to the reactor vessel.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, 4, and 5*.

ACTION:

a. In OPERATIONAL CONDITION 1, 2, or 3 with the suppression chamber water level less than the above limit, restore the water level to within the limit within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 4 or 5* with the suppression chamber water level less than the above limit or drained and the above required conditions not satisfied, suspend CORE ALTERATIONS and all operations that have a potential for draining the reactor vessel and lock the reactor mode switch in the Shutdown position. Establish SECONDARY CONTAINMENT INTEGRITY within 8 hours.

#See Specification 3.6.2.1 for pressure suppression requirements.
*The suppression chamber is not required to be OPERABLE provided that the reactor vessel head is removed, the cavity is flooded or being flooded from the suppression pool, the spent fuel pool gates are removed when the cavity is flooded, and the water level is maintained within the limits of Specifications 3.9.8 and 3.9.9.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION (Continued)

c. With one suppression chamber water level instrumentation channel inoperable, restore the inoperable channel to OPERABLE status within 7 days or verify the suppression chamber water level to be greater than or equal to 26 ft 2½ in or 14 ft 0 in, as applicable, at least once per 12 hours by local indication.

d. With both suppression chamber water level instrumentation channels inoperable, restore at least one inoperable channel to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours and verify the suppression chamber water level to be greater than or equal to 26 ft 2½ in or 14 ft 0 in, as applicable, at least once per 12 hours by local indication.

SURVEILLANCE REQUIREMENTS

4.5.3.1 The suppression chamber shall be determined OPERABLE by verifying:

a. The water level to be greater than or equal to, as applicable:

1. 26 ft 2½ in at least once per 24 hours.

2. 14 ft 0 in at least once per 12 hours.

b. Two suppression chamber water level instrumentation channels OPERABLE by performance of a:

1. CHANNEL CHECK at least once per 24 hours,

2. CHANNEL FUNCTIONAL TEST at least once per 31 days, and

3. CHANNEL CALIBRATION at least once per 18 months,

with the low water level alarm setpoint at greater than or equal to 26 ft 4in.**

4.5.3.2 With the suppression chamber level less than the above limit or drained in OPERATIONAL CONDITION 4 or 5*, at least once per 12 hours:

a. Verify the required conditions of Specification 3.5.3.b to be satisfied, or

b. Verify footnote conditions* to be satisfied.

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

LIMITING CONDITION FOR OPERATION

3.6.1.2 Primary containment leakage rates shall be limited to:

a. An overall integrated leakage rate of less than or equal to L_a, 0.635 percent by weight of the containment air per 24 hours at P_a, 39.6 psig.

b. A combined leakage rate of less than or equal to 0.60 L_a for all penetrations and all valves listed in Table 3.6.3-1, except for main steam isolation valves and valves which are hydrostatically leak tested per Table 3.6.3-1, subject to Type B and C tests when pressurized to P_a, 39.6 psig.

c. *Less than or equal to 100 scf per hour for all four main steam lines through the isolation valves when tested at 25.0 psig.

d. A combined leakage rate of less than or equal to 1 gpm times the total number of ECCS and RCIC containment isolation valves in hydrostatically tested lines which penetrate the primary containment, when tested at 1.10 P_a, 43.6 psig.

APPLICABILITY: When PRIMARY CONTAINMENT INTEGRITY is required per Specification 3.6.1.1.

ACTION:

With:

a. The measured overall integrated primary containment leakage rate exceeding 0.75 L_a, or

b. The measured combined leakage rate for all penetrations and all valves listed in Table 3.6.3-1, except for main steam isolation valves and valves which are hydrostatically leak tested per Table 3.6.3-1, subject to Type B and C tests exceeding 0.60 L_a, or

c. The measured leakage rate exceeding 100 scf per hour for all four main steam lines through the isolation valves, or

d. The measured combined leakage rate for all ECCS and RCIC containment isolation valves in hydrostatically tested lines which penetrate the primary containment exceeding 1 gpm times the total number of such valves,

*Exemption to Appendix "J" of 10 CFR 50.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION (Continued)

restore:

a. The overall integrated leakage rate(s) to less than or equal to 0.75 L_a, and

b. The combined leakage rate for all penetrations and all valves listed in Table 3.6.3-1, except for main steam isolation valves and valves which are hydrostatically leak tested per Table 3.6.3-1, subject to Type B and C tests to less than or equal to 0.60 L_a, and

c. The leakage rate to less than or equal to 100 scf per hour for all four main steam lines through the isolation valves, and

d. The combined leakage rate for all ECCS and RCIC containment isolation valves in hydrostatically tested lines which penetrate the primary containment to less than or equal to 1 gpm times the total number of such valves,

prior to increasing reactor coolant system temperature above 200°F.

SURVEILLANCE REQUIREMENTS

4.6.1.2 The primary containment leakage rates shall be demonstrated at the following test schedule and shall be determined in conformance with the criteria specified in Appendix J of 10 CFR Part 50 using the methods and provisions of ANSI N45.4-1972:

a. Three Type A Overall Integrated Containment Leakage Rate tests shall be conducted at 40 ± 10 month intervals during shutdown at P_a, 39.6 psig, during each 10-year service period. The third test of each set shall be conducted during the shutdown for the 10-year plant inservice inspection.

b. If any periodic Type A test fails to meet 0.75 L_a, the test schedule for subsequent Type A tests shall be reviewed and approved by the Commission. If two consecutive Type A tests fail to meet 0.75 L_a, a Type A test shall be performed at least every 18 months until two consecutive Type A tests meet 0.75 L_a, at which time the above test schedule may be resumed.

c. The accuracy of each Type A test shall be verified by a supplemental test which:

   1. Confirms the accuracy of the test by verifying that the difference between the supplemental data and the Type A test data is within 0.25 L_a.

   2. Has duration sufficient to establish accurately the change in leakage rate between the Type A test and the supplemental test.

   3. Requires the quantity of gas injected into the containment or bled from the containment during the supplemental test to be equivalent to at least 25% of the total measured leakage at P_a, 39.6 psig.

PRIMARY CONTAINMENT AIR LOCKS

LIMITING CONDITION FOR OPERATION

3.6.1.3 Each primary containment air lock shall be OPERABLE with:

a. Both doors closed except when the air lock is being used for normal transit entry and exit through the containment, then at least one air lock door shall be closed, and

b. An overall air lock leakage rate of less than or equal to 0.05 L_a at P_a, 39.6 psig.

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

ACTION:

a. With one primary containment air lock door inoperable:

1. Maintain at least the OPERABLE air lock door closed and either restore the inoperable air lock door to OPERABLE status within 24 hours or lock the OPERABLE air lock door closed.

2. Operation may then continue until performance of the next required overall air lock leakage test provided that the OPERABLE air lock door is verified to be locked closed at least once per 31 days.

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

4. The provisions of Specification 3.0.4 are not applicable.

b. With the primary containment air lock inoperable, except as a result of an inoperable air lock door, maintain at least one air lock door closed; restore the inoperable air lock to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

*See Special Test Exception 3.10.1.

PRIMARY CONTAINMENT STRUCTURAL INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.1.5 The structural integrity of the primary containment shall be maintained at a level consistent with the acceptance criteria in Specification 4.6.1.5.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With more than one tendon with an obseved lift-off force between the predicted lower limit and 90% of the predicted lower limit or with one tendon below 90% of the predicted lower limit, restore the tendon(s) to the required level of integrity within 15 days and perform an engineering evaluation of the containment and provide a Special Report to the Commission within 30 days in accordance with Specification 6.6C. or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With any other abnormal degradation of the structural integrity at a level below the acceptance criteria of Specification 4.6.1.5, restore the containment vessel to the required level of integrity within 72 hours and perform an engineering evaluation of the containment and provide a Special Report to the Commission within 15 days in accordance with Specification 6.6C. or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

4.6.1.5 Primary Containment Tendons. The primary containment structural integrity shall shall be demonstrated at the end of 1, 3 and 5 years after the initial structural integrity test (ISIT) and every 5 years thereafter in accordance with Table 4.6.1.5-1. The structural integrity shall be demonstrated by:

a. Determining that a representative sample of at least 13 tendons, 8 horizontal and 5 vertical, selected in accordance with Table 4.6.1.5-1 have a lift-off force equal to or greater than the minimum values listed in Table 4.6.1.5-2 at the first year inspection. For subsequent inspections, for tendons and periodicities per Table 4.6.1.5-1, the minimum lift-off forces shall be decreased by the amount X2 log $t/_{to}$ for V tendons and Y2 log $t/_{to}$ for hoop tendons where t is the time interval in years from initial tensioning of the tendon to the current testing date and to is the time interval in years from initial tensioning of the tendon to the first inspection and is equal to 2 years and the values X1, X2, Y1 and Y2 are in accordance with the values listed in Table 4.6.1.5-2 for the surveillance tendon. This test shall include essentially a complete detensioning of tendons selected in accordance with Table 4.6.1.5-1 in which the tendon is detensioned to determine if any wires or strands are broken or damaged. Tendons found acceptable during this test shall be retensioned to their observed lift-off force, ± 3%. During retensioning of these tendons, the change in load and elongation shall be measured simultaneously at a minimum of three, approximately equally spaced, levels of force between the seating force and zero. If elongation corresponding to a specific load differs by more than 5% from that recorded during installation of tendons, an investigation should be made to ensure that such difference is not related to wire failures or slip of wires in anchorages. If the lift-off force of any one tendon in the total sample population lies between the predicted lower limit and 90% of the predicted lower limit, two tendons, one on each side of this tendon, shall be checked for their lift-off force. If both these adjacent tendons are found acceptable, the surveillance program may proceed considering the single deficiency as unique and acceptable. The tendon(s) shall be restored to the required level of integrity. More than one tendon below the predicted bounds out of the original sample population or the lift-off force of a selected tendon lying below 90% of the prescribed lower limit is evidence of abnormal degradation of the containment structure.

b. Performing tendon detensioning and material tests and inspections of a previously stressed tendon wire or strand from one tendon of each group, hoop and V, and determining that over the entire length of the removed wire or strand that:

   1. The tendon wires or strands are free of corrosion, cracks and damage.

   2. A minimum tensile strength value of 240 ksi, the guaranteed ultimate strength of the tendon material, for at least three wire or strand samples, one from each end and one at mid-length, cut from each removed wire or strand. Failure of any one of the wire or strand samples to meet the minimum tensile strength test is evidence of abnormal degradation of the primary containment structure.

TABLE 4.6.1.5-1

TENDON SURVEILLANCE

	TENDON NUMBERS									
Years After Initial Structural Integrity Test	1		3		5		10		15	
Type of Inspection	H	V	H	V	H	V	H	V	H	V
Visual Inspection of End Anchorages Adjacent Concrete Surface and Prestress Monitoring Tests	48AC 56CB 12CB 70B 20CB 1CB 12AC 56BA 21AC	15C 15A 20A 47C 29A	48AC 2CB 14AC 24BA 37CB 47CB 57CB 60B	15C 6C 17A 32C 42C	48AC 3BA 12BA 21CB 23BA 38CB 49AC 68B	15C 28A 23A 5B 31C	48AC 4BA 41CB 50AC	15C 30B 22A	48AC 50CB 53BA 57AC	15C 19A 13B
Detensioning and Material Tests	20CB	47C	2CB	42C	23BA	31C	4BA	22A	50CB	19A

	TENDON NUMBERS									
Years After Initial Structural Integrity Test	20		25		30		35		40	
Type of Inspection	H	V	H	V	H	V	H	V	H	V
Visual Inspection of End Anchorages Adjacent Concrete Surface and Prestress Monitoring Tests	48AC 39CB 49BA 71D	15C 25B 11A	48AC 1BA 47AC 57BA	15C 3B 12A	48AC 48CB 51AC 58BA	15C 7B 18A	48AC 49CB 51BA 59D	15C 25A 18B	48AC 36CB 48BA 69D	15C 13A 27B
Detensioning and Material Tests	49BA	11A	47AC	3B	48CB	18A	51BA	18B	36CB	13A

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 with the drywell and/or suppression chamber purge supply and exhaust butterfly isolation valves open for inerting, de-inerting and pressure control, provided that each butterfly valve is blocked so as not to open more than 50°. Purging through the Standby Gas Treatment System shall be restricted to less than or equal to 90 hours per 365 days.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

With a drywell and/or suppression chamber purge supply and/or exhaust butterfly isolation valve open for other than inerting, de-inerting or pressure control, or not blocked to less than or equal to 50° open, close the butterfly valve(s) within one hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.8.1 When being opened, the drywell and suppression chamber purge supply and exhaust butterfly isolation valves shall be verified to be blocked so as to open to less than or equal to 50° open, unless so verified within the previous 31 days.

4.6.1.8.2 Each drywell and suppression chamber purge supply and exhaust butterfly isolation valve shall be demonstrated OPERABLE at least once per 92 days by verifying that the measured leakage rate is less than or equal to 0.05 L_a.

4.6.1.8.3 The cumulative time that the drywell and suppression chamber purge system has been in operation purging through the Standby Gas Treatment System shall be verified to be less than or equal to 90 hours per 365 days prior to use in this mode of operation.

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 131,900 ft^3 and 128,800 ft^3, equivalent to a level between 26 ft. 10 in. and 26 ft. 2½ in., and a
2. Maximum average temperature of 100°F* during OPERATIONAL CONDITION 1 or 2, except that the maximum average temperature may be permitted to increase to:
   a) 105°F,## during testing which adds heat to the suppression chamber.
   b) 110°F with THERMAL POWER less than or equal to 1% of RATED THERMAL POWER.
   c) 120°F with the main steam line isolation valves closed following a scram.

b. Drywell-to-suppression chamber bypass leakage less than or equal to 10% of the acceptable $A/\sqrt{k}$ design value of 0.03 ft^2.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

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

b. In OPERATIONAL CONDITION 1 or 2 with the suppression chamber average water temperature greater than or equal to 100°F, restore the average temperature to less than or equal to 100°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 or equal to 100°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 110°F, place the reactor mode switch in the Shutdown position and operate at least one residual heat removal loop in the suppression pool cooling mode.
3. With the suppression chamber average water temperature greater than 120°F, depressurize the reactor pressure vessel to less than 200 psig within 12 hours.

#See Specification 3.5.3 for ECCS requirements.
##See Special Test Exception 3.10.8.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

c. With one suppression chamber water level instrumentation channel inoperable and/or with one suppression pool water temperature instrumentation division inoperable, restore the inoperable instrumentation to OPERABLE status within 7 days or verify suppression chamber water level and/or temperature to be within the limits at least once per 12 hours by local indication.

d. With both suppression chamber water level instrumentation channels inoperable and/or with both suppression pool water temperature instrumentation divisions inoperable, restore at least one inoperable water level channel and one water temperature division to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

e. With the drywell-to-suppression chamber bypass leakage in excess of the limit, restore the bypass leakage to within the limit prior to increasing reactor coolant temperature above 200°F.

SURVEILLANCE REQUIREMENTS

4.6.2.1 The suppression chamber shall be demonstrated OPERABLE:

a. By verifying the suppression chamber water volume to be within the limits at least once per 24 hours.

b. At least once per 24 hours in OPERATIONAL CONDITION 1 or 2 by verifying the suppression chamber average water temperature to be less than or equal to 100°F, except:

1. At least once per 5 minutes during testing which adds heat to the suppression chamber, by verifying the suppression chamber average water temperature less than or equal to 105°F.

2. At least once per 60 minutes when suppression chamber average water temperature is greater than 100°F, by verifying suppression chamber average water temperature less than or equal to 110°F and THERMAL POWER less than or equal to 1% of RATED THERMAL POWER.

3. At least once per 30 minutes following a scram with suppression chamber average water temperature greater than or equal to 100°F, by verifying suppression chamber average water temperature less than or equal to 120°F.

SURVEILLANCE REQUIREMENTS (Continued)

c. By verifying at least two suppression chamber water level instrumentation channels and at least 14 suppression pool water temperature instrumentation channels, 7 in each of two divisions, OPERABLE by performance of a:

1. CHANNEL CHECK at least once per 24 hours,

2. CHANNEL FUNCTIONAL TEST at least once per 31 days, and

3. CHANNEL CALIBRATION at least once per 18 months,

with the water level and temperature alarm setpoint for:

1. High water level $\leq$ 26 ft. 8 in.

2. Low water level $\geq$ 26 ft. 4 in.

3. High temperature $\leq$ 100°F

d. By conducting drywell-to-suppression chamber bypass leak tests and verifying that the $A/\sqrt{k}$ calculated from the measured leakage is within the specified limit when drywell-to-suppression chamber bypass leak tests are conducted:

1. At least once per 18 months at an initial differential pressure of 1.5 psi, and

2. At the first refueling outage and then on the schedule required for Type A Overall Integrated Containment Leakage Rate tests by Specification 4.6.1.2.a; at an initial differential pressure of 5 psi,

except that, if the first two 5 psi leak tests performed up to that time result in:

1. A calculated $A/\sqrt{k}$ within the specified limit, and

2. The $A/\sqrt{k}$ calculated from the leak tests at 1.5 psi is $\leq$ 20% of the specified limit,

then the leak tests at 5 psi may be discontinued.

SURVEILLANCE REQUIREMENTS (Continued)

If any 1.5 psi or 5 psi leak test results in:

1. A calculated $A/\sqrt{k}$ greater than the specified limit, or

2. A calculated $A/\sqrt{k}$ from a 1.5 psi leak test > 20% of the specified limit,

then the test schedule for subsequent tests shall be reviewed by the Commission.

If two consecutive 1.5 psi leak tests result in a calculated $A/\sqrt{k}$ greater than the specified limit, then:

1. A 1.5 psi leak test shall be performed at least once per 9 months until two consecutive 1.5 psi leak tests result in the calculated $A/\sqrt{k}$ within the specified limits, and

2. A 5 psi leak test, performed with the second consecutive successful 1.5 psi leak test, results in a calculated $A/\sqrt{k}$ within the specified limit, after which the above schedule for only 1.5 psi leak tests may be resumed.

If two consecutive 5 psi leak tests result in a calculated $A/\sqrt{k}$ greater than the specified limit, then a 5 psi leak test shall be performed at least once per 9 months until two consecutive 5 psi leak tests result in a calculated $A/\sqrt{k}$ within the specified limit, after which the above schedule for only 1.5 psi leak tests may be resumed.

SUPPRESSION POOL SPRAY

LIMITING CONDITION FOR OPERATION

3.6.2.2 The suppression pool spray mode of the residual heat removal (RHR) system shall be OPERABLE with two independent loops, each loop consisting of:

a. One OPERABLE RHR pump, and

b. An OPERABLE flow path capable of recirculating water from the suppression chamber.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one suppression pool spray loop inoperable, restore the inoperable loop to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With both suppression pool spray loops inoperable, restore at least one loop to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN* within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.2 The suppression pool spray mode of the RHR system shall be demonstrated OPERABLE:

a. At least once per 31 days by 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.

b. By verifying that each of the required RHR pumps develops a flow of at least 450 gpm on recirculation flow through the suppression pool spray sparger when tested pursuant to Specification 4.0.5.

*Whenever both RHR subsystems are inoperable, if unable to attain COLD SHUTDOWN as required by this ACTION, maintain reactor coolant temperature as low as practical by use of alternate heat removal methods.

SUPPRESSION POOL COOLING

LIMITING CONDITION FOR OPERATION

3.6.2.3 The suppression pool cooling mode of the residual heat removal (RHR) system shall be OPERABLE with two independent loops, each loop consisting of:

a. One OPERABLE RHR pump; and

b. An OPERABLE flow path capable of recirculating water from the suppression chamber through an RHRSW heat exchanger.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one suppression pool cooling loop inoperable, restore the inoperable loop to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With both suppression pool cooling loops inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN* within the next 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.3 The suppression pool cooling mode of the RHR system shall be demonstrated OPERABLE:

a. At least once per 31 days by 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.

b. By verifying that each of the required RHR pumps develops a flow of at least 7200 gpm on recirculation flow through the RHR heat exchanger and the suppression pool when tested pursuant to Specification 4.0.5.

*Whenever both RHR subsystems are inoperable, if unable to attain COLD SHUTDOWN as required by this ACTION, maintain reactor coolant temperature as low as practical by use of alternate heat removal methods.

TABLE 3.6.3-1

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	VALVE GROUP[a]	MAXIMUM ISOLATION TIME (Seconds)
a. Automatic Isolation Valves		
1. Main Steam Isolation Valves#	1	5*
1B21-F022A, B, C, D[b]		
1B21-F028A, B, C, D[b]		
2. Main Steam Line Drain Valves#	1	
1B21-F016		≤ 15
1B21-F019		≤ 15
1B21-F067A, B, C, D[b]		≤ 23
3. Reactor Coolant System Sample Line Valves[c]#	3	≤ 5
1B33-F019		
1B33-F020		
4. Drywell Equipment Drain Valves	2	≤ 20
1RE024		
1RE025		
1RE026		
1RE029		
5. Drywell Floor Drain Valves	2	≤ 20
1RF012		
1RF013		
6. Reactor Water Cleanup Suction Valves	5	≤ 30
1G33-F001[d]		
1G33-F004		
7. RCIC Steam Line Valves	8	
1E51-F008[e]		≤ 20
1E51-F063		≤ 15
1E51-F064[f]#		≤ 15
1E51-F076		≤ 15

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	VALVE GROUP[a]	MAXIMUM ISOLATION TIME (Seconds)
Automatic Isolation Valves (Continued)		
8. Containment Vent and Purge Valves#	4	
1VQ026		≤ 10**
1VQ027		≤ 10**
1VQ029		≤ 10**
1VQ030		≤ 10**
1VQ031		≤ 10**
1VQ032		≤ 5
1VQ034		≤ 10**
1VQ035		≤ 5
1VQ036		≤ 10**
1VQ040		≤ 10**
1VQ042		≤ 10**
1VQ043		≤ 10**
1VQ047		≤ 5
1VQ048		≤ 5
1VQ050		≤ 5
1VQ051		≤ 5
1VQ068		≤ 5
9. RCIC Turbine Exhaust Vacuum Breaker Line Valves	9	N.A.
1E51-F080		
1E51-F086		
10. LPCS, HPCS, RCIC, RHR Injection Testable Check Bypass Valves[g]	2	N.A.
1E21-F333		
1E22-F354		
1E12-F327A, B, C		
1E51-F354		
1E51-F355		

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	VALVE GROUP[a]	MAXIMUM ISOLATION TIME (Seconds)
Automatic Isolation Valves (Continued)		
11. Containment Monitoring Valves	2	≤ 5
1CM017A,B#		
1CM018A,B#		
1CM019A,B#		
1CM020A,B#		
1CM021B[h]		
1CM022A[h]		
1CM025A[h]		
1CM026B[h]		
1CM027		
1CM028		
1CM029		
1CM030		
1CM031		
1CM032		
1CM033		
1CM034		
12. Drywell Pneumatic Valves	2	
1IN001A and B		≤ 40
1IN017#		≤ 30
1IN074#		≤ 30
1IN075#		≤ 30
1IN031#		≤ 5
13. RHR Shutdown Cooling Mode Valves	6	
1E12-F008		≤ 41
1E12-F009		≤ 41
1E12-F023		≤ 90
1E12-F053 A and B		≤ 29
1E12-F099A and B[g][i]		≤ 30

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	VALVE GROUP[a]	MAXIMUM ISOLATION TIME (Seconds)
Automatic Isolation Valves (Continued)		
14. Tip Guide Tube Valve Ball Valve 1C51-J004	7	N.A.
15. Reactor Building Closed Cooling Water System Valves 1WR029 1WR040 1WR179 1WR180	2	≤ 30
16. Primary Containment Chilled Water Inlet Valves#	2	
1VP113 A and B		≤ 90
1VP063 A and B		≤ 40
17. Primary Containment Chilled Water Outlet Valves#	2	
1VP053 A and B		≤ 40
1VP114 A and B		≤ 90
18. Recirc. Hydraulic Flow Control Line Valves[g] 1B33-F338 A and B 1B33-F339 A and B 1B33-F340 A and B 1B33-F341 A and B 1B33-F342 A and B 1B33-F343 A and B 1B33-F344 A and B 1B33-F345 A and B	2	≤ 5
19. Feedwater Testable Check Valves 1B21-F032 A and B	2	N.A.

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	VALVE GROUP[a]	MAXIMUM ISOLATION TIME (Seconds)
b. Manual Isolation Valves#		
1. 1FC086		N.A.
2. 1FC113		N.A.
3. 1FC114		N.A.
4. 1FC115		N.A.
5. 1MC027[1]		N.A.
6. 1MC033[1]		N.A.
7. 1SA042[1]		N.A.
8. 1SA046[1]		N.A.

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER

d. Other Isolation Valves

1. MSIV Leakage Control System

1E32-F001A, E, J, N[b]

2. Reactor Feedwater and RWCU System Return

1B21-F010A, B
1B21-F065A, B
1G33-F040

3. Residual Heat Removal/Low Pressure Coolant Injection System

1E12-F042A, B, C
1E12-F016A, B
1E12-F017A, B
1E12-F004A, B, C[j]
1E12-F027A, B[j]
1E12-F024A, B[j]
1E12-F021[j]
1E12-F302[j]
1E12-F064A, B, C[j]
1E12-F011A, B[j]#
1E12-F088A, B, C[j]
1E12-F025A, B, C[j]
1E12-F030[j]
1E12-F005[j]
1E12-F073A, B[j]#
1E12-F074A, B[j]#
1E12-F055A, B[j]
1E12-F036A, B[j]
1E12-F311A, B[j]
1E12-F041A, B, C[k]
1E12-F050A, B[k]

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER

Other Isolation Valves (Continued)

4. Low Pressure Core Spray System

1E21-F005
1E21-F001(j)
1E21-F012(j)
1E21-F011(j)
1E21-F018(j)
1E21-F031(j)
1E21-F006(k)

5. High Pressure Core Spray System

1E22-F004
1E22-F015(j)
1E22-F023(j)
1E22-F012(j)
1E22-F014(j)
1E22-F005(k)

6. Reactor Core Isolation Cooling System

1E51-F013
1E51-F069
1E51-F028
1E51-F068
1E51-F040
1E51-F031(j)
1E51-F019(j)
1E51-F065(k)
1E51-F066(k)

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER

Other Isolation Valves (Continued)

7. Post LOCA Hydrogen Control

   1HG001A, B
   1HG002A, B
   1HG005A, B
   1HG006A, B

8. Standby Liquid Control System

   1C41-F004A, B
   1C41-F007

9. Reactor Recirculation Seal Injection

   1B33-F013A, B(j)
   1B33-F017A, B(j)

10. Drywell Pneumatic System

    1IN018

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* But ≥ 3 seconds.
\# The provisions of Specification 3.0.4 are not applicable.
(a) See Specification 3.3.2, Table 3.3.2-1, for isolation signal(s) that operates each valve group.
(b) Not included in total sum of Type B and C tests.
(c) May be opened on an intermittent basis under administrative control.
(d) Not closed by SLCS actuation.
(e) Not closed by Trip Functions 5a, b or c, Specification 3.3.2, Table 3.3.2-1.
(f) Not closed by Trip Functions 4a, c, d, e or f of Specification 3.3.2, Table 3.3.2-1.
(g) Not subject to Type C leakage test.
(h) Opens on an isolation signal. Valves will be open during Type A test. No Type C test required.
(i) Also closed by drywell pressure-high signal.
(j) Hydraulic leak test at 43.6 psig.
(k) Not subject to Type C leakage test - leakage rate tested per Specification 4.4.3.2.2.
(l) These penetrations are provided with removable spools outboard of the outboard isolation valve. During operation, these lines will be blind flanged using a double O-ring and a type B leak test. In addition, the packing of these isolation valves will be soap-bubble tested to ensure insignificant or no leakage at the containment test pressure each refueling outage.
** These valves shall have a maximum isolation time of 40 seconds until STARTUP following the first refueling outage.

3/4.6.4 VACUUM RELIEF

LIMITING CONDITION FOR OPERATION

3.6.4 All suppression chamber - drywell vacuum breakers shall be OPERABLE and closed.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one suppression chamber - drywell vacuum breaker inoperable and/or open, within 4 hours close the manual isolation valves on both sides of the inoperable and/or open vacuum breaker. Restore the inoperable and/or open vacuum breaker to OPERABLE and closed status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one position indicator of any OPERABLE suppression chamber - drywell vacuum breaker inoperable, restore the inoperable position indicator to OPERABLE status within 14 days or visually verify the vacuum breaker to be closed at least once per 24 hours. Otherwise, declare the vacuum breaker inoperable.

SURVEILLANCE REQUIREMENTS

4.6.4.1 Each suppression chamber - drywell vacuum breaker shall be:

a. Verified closed at least once per 7 days.

b. Demonstrated OPERABLE:

1. At least once per 31 days and within 12 hours after any discharge of steam to the suppression chamber from the safety-relief valves, by cycling each vacuum breaker through at least one complete cycle of full travel.

2. At least once per 31 days by verifying both position indicators OPERABLE by performance of a CHANNEL FUNCTIONAL TEST.

3. At least once per 18 months by;

a) Verifying the force required to open the vacuum breaker, from the closed position, to be less than or equal to 0.5 psid, and

b) Verifying both position indicators OPERABLE by performance of a CHANNEL CALIBRATION.

SURVEILLANCE REQUIREMENTS (Continued)

4.6.4.2 The manual isolation valves on both sides of an inoperable and/or open suppression chamber-drywell vacuum breaker shall be verified to be closed at least once per 7 days.

4.6.4.3 Vacuum breaker header flanges which have been broken shall be leak tested after re-making by Type B test at 39.6 psig per Specification 4.6.1.2.d.

3/4.6.5 SECONDARY CONTAINMENT

SECONDARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.5.1 SECONDARY CONTAINMENT INTEGRITY shall be maintained.

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

ACTION:

Without SECONDARY CONTAINMENT INTEGRITY:

a. In OPERATIONAL CONDITION 1, 2 or 3, restore SECONDARY CONTAINMENT INTEGRITY within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

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

SURVEILLANCE REQUIREMENTS

4.6.5.1 SECONDARY CONTAINMENT INTEGRITY shall be demonstrated by:

a. Verifying at least once per 24 hours that the pressure within the secondary containment is less than or equal to 0.25 inches of vacuum water gauge.#

b. Verifying at least once per 31 days that:

   1. At least one door in each access to the secondary containment is closed.

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

c. At least once per 18 months:

   1. Verifying that one standby gas treatment subsystem will draw down the secondary containment to greater than or equal to 0.25 in. of vacuum water gauge in less than or equal to 300 seconds, and

   2. Operating one standby gas treatment subsystem for one hour and maintaining greater than or equal to 0.25 inches of vacuum water gauge in the secondary containment at a flow rate not exceeding 4000 CFM ± 10%.

*When irradiated fuel is being handled in the secondary containment and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.
#SECONDARY CONTAINMENT INTEGRITY is maintained when secondary containment vacuum is less than required for up to 1 hour solely due to Reactor Building ventilation system failure.

SECONDARY CONTAINMENT AUTOMATIC ISOLATION DAMPERS

LIMITING CONDITION FOR OPERATION

3.6.5.2 The secondary containment ventilation system automatic isolation dampers shown in Table 3.6.5.2-1 shall be OPERABLE with isolation times equal to or less than shown in Table 3.6.5.2-1.

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

ACTION:

With one or more of the secondary containment ventilation system automatic isolation dampers shown in Table 3.6.5.2-1 inoperable:

a. Maintain at least one isolation damper OPERABLE in each affected penetration that is open and within 8 hours, either:

   1. Restore the inoperable damper to OPERABLE status, or

   2. Isolate each affected penetration by use of at least one deactivated automatic damper secured in the isolation position, or

   3. Isolate each affected penetration by use of at least one closed manual valve or blind flange.

b. 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.

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

SURVEILLANCE REQUIREMENTS

4.6.5.2 Each secondary containment ventilation system automatic isolation damper shown in Table 3.6.5.2-1 shall be demonstrated OPERABLE:

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

b. During COLD SHUTDOWN or REFUELING at least once per 18 months by verifying that on a containment isolation test signal each isolation damper actuates to its isolation position.

c. By verifying the isolation time to be within the limit when tested pursuant to Specification 4.0.5.

*When irradiated fuel is being handled in the secondary containment and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

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 OPERABLE 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 and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.5.3 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 for at least 10 hours with the heaters OPERABLE.

*When irradiated fuel is being handled in the secondary containment and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

#The normal or emergency power source may be inoperable in Operational Condition *.

SURVEILLANCE REQUIREMENTS (Continued)

b. At least once per 18 months or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire, or chemical release in any ventilation zone communicating with the subsystem by:

1. Verifying that the subsystem satisfies the in-place testing acceptance criteria and uses the test procedures of Regulatory Positions C.5.a, C.5.c and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rate is 4000 cfm ± 10%.

2. Verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978.

3. Verifying a subsystem flow rate of 4000 cfm ± 10% during system operation when tested in accordance with ANSI N510-1975.

c. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978.

d. At least once per 18 months by:

1. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than or equal to 8 inches Water Gauge while operating the filter train at a flow rate of 4000 cfm ± 10%.

2. Verifying that the filter train starts and isolation dampers open on each of the following test signals:

a. Reactor Building exhaust plenum radiation - high,

b. Drywell pressure - high,

c. Reactor vessel water level - low low, level 2, and

d. Fuel pool vent exhaust radiation - high.

3. Verifying that the heaters dissipate 20 ± 2.0 kw when tested in accordance with ANSI N510-1975.

SURVEILLANCE REQUIREMENTS

c. At least once per 18 months by:

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

2. Verifying that the system is capable of providing a flow of greater than or equal to 600 gpm to the reactor vessel when steam is supplied to the turbine at a pressure of 150 ± 15 psig using the test flow path.* 5

3. Performing a CHANNEL CALIBRATION of the discharge line "keep filled" pressure alarm instrumentation and verifying the low pressure setpoint to be ≥ 62 psig.

d. By demonstrating MCC-121y and the 250-volt battery and charger OPERABLE: 18

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

a) MCC-121y is energized, and has correct breaker alignment, indicated power availability from the charger and battery, and voltage on the panel with an overall voltage of greater than or equal to 250 volts.
b) The electrolyte level of each pilot cell is above the plates,
c) The pilot cell specific gravity, corrected to 77°F, is greater than or equal to 1.200, and
d) The overall battery voltage is greater than or equal to 250 volts.

2. At least once per 92 days by verifying that:

a) The voltage of each connected battery is greater than or equal to 250 volts under float charge and has not decreased more than 12 volts from the value observed during the original test,
b) The specific gravity, corrected to 77°F, of each connected cell is greater than or equal to 1.195 and has not decreased more than 0.05 from the value observed during the previous test, and
c) The electrolyte level of each connected cell is above the plates.

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

a) The battery shows no visual indication of physical damage or abnormal deterioration, and
b) Battery terminal connections are clean, tight, free of corrosion and coated with anti-corrosion material.

*The provisions of Specification 4.0.4 are not applicably provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the tests.

SURVEILLANCE REQUIREMENTS

4.7.5.1.1 The fire suppression water system shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve, manual, power operated or automatic, in the flow path is in its correct position.

b. At least once per 12 months by cycling each testable valve in the flow path through at least one complete cycle of full travel.

c. At least once per 18 months by performing a system functional test which includes simulated automatic actuation of the system throughout its operating sequence, and:

1. Verifying that each automatic valve in the flow path actuates to its correct position,

2. Verifying that each fire suppression pump develops at least 3750 gpm at a system head of 205 feet,

3. Cycling each valve in the flow path that is not testable during plant operation through at least one complete cycle of full travel, and

4. Verifying that each fire suppression pump starts sequentially to maintain the fire suppression water system pressure greater than or equal to 118 psig.

d. At least once per 3 years by performing a flow test of the system in accordance with Chapter 5, Section 11 of the Fire Protection Handbook, 14th Edition, published by the National Fire Protection Association.

4.7.5.1.2 Each diesel driven fire suppression pump shall be demonstrated OPERABLE:

a. At least once per 31 days by:

1. Verifying the fuel day tank contains at least 130 gallons of fuel.

2. Starting:

a) The fuel transfer pump and transferring fuel from the storage tank to the day tank.

b) The diesel driven pump from ambient conditions and operating for at least 30 minutes on recirculation flow.

DELUGE AND/OR SPRINKLER SYSTEMS

LIMITING CONDITION FOR OPERATION

3.7.5.2 The deluge and sprinkler systems of Unit 1 and Unit 2 shown in Table 3.7.5.2-1 shall be OPERABLE.*

APPLICABILITY: Whenever equipment protected by the deluge/sprinkler systems are required to be OPERABLE.

ACTION:

a. With one or more of the deluge and/or sprinkler systems shown in Table 3.7.5.2-1 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. Restore the system to OPERABLE status within 14 days or, in lieu of any other report required by Specification 6.6.B, prepare and submit a Special Report to the Commission pursuant to Specification 6.6.C within the next 30 days outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system to OPERABLE status.

b. The provisions of Specification 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.5.2 Each of the above required deluge and sprinkler systems shown in Table 3.7.5.2-1 shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve, (manual, power operated or automatic), in the flow path is in its correct position.

b. At least once per 12 months by cycling each testable valve in the flow path through at least one complete cycle of full travel.

c. At least once per 18 months:

1. By performing a system functional test which includes simulated automatic actuation of the system, and:

a) Verifying that the automatic valves in the flow path actuate to their correct positions on a test signal, and

b) Cycling each valve in the flow path that is not testable during plant operation through at least one complete cycle of full travel.

*The normal or emergency power source may be inoperable in OPERATIONAL CONDITION 4 or 5 or when defueled.

CO_2 SYSTEMS

LIMITING CONDITION FOR OPERATION

3.7.5.3 The following low pressure CO_2 systems of Unit 1 and Unit 2 shall be OPERABLE.*

a. Division 1 diesel generator 0 room.

b. Division 2 diesel generator 1A room.

c. Division 3 diesel generator 1B room.

d. Unit 2 Division 2 diesel generator 2A room.

APPLICABILITY: Whenever equipment protected by the low pressure CO_2 systems is required to be OPERABLE.

ACTION:

a. With one or more of the above required low pressure CO_2 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. Restore the system to OPERABLE status within 14 days or, in lieu of any other report required by Specification 6.6.B, prepare and submit a Special Report to the Commission pursuant to Specification 6.6.C within the next 30 days outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system to OPERABLE status. 18

b. The provisions of Specification 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.5.3 Each of the above required low pressure CO_2 systems shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying CO_2 storage tank level to be greater than 50% full and pressure to be greater than 290 psig, and 13

b. At least once per 31 days by verifying that each valve (manual, power operated, or automatic) in the flow path is in the correct position. 18

c. At least once per 18 months by verifying:

1. The system valves and associated motor operated ventilation dampers actuate, manually and automatically, upon receipt of a simulated actuation signal, and

2. Flow from each nozzle during a "Puff Test."

*The normal or emergency power source may be inoperable in OPERATIONAL CONDITION 4 or 5 or when defueled.

FIRE HOSE STATIONS

LIMITING CONDITION FOR OPERATION

3.7.5.4 The fire hose stations of Unit 1 and Unit 2 shown in Table 3.7.5.4-1 shall be OPERABLE.

APPLICABILITY: Whenever equipment in the areas protected by the fire hose stations is required to be OPERABLE.

ACTION:

a. With one or more of the fire hose stations shown in Table 3.7.5.4-1 inoperable, route an additional fire hose of equal or greater diameter to the unprotected area(s)/zone(s) from an OPERABLE hose station within 1 hour if the inoperable fire hose is the primary means of fire suppression; otherwise, route the additional hose within 24 hours. Restore the inoperable fire hose station(s) to OPERABLE status within 14 days or, in lieu of any other report required by Specification 6.6.B, prepare and submit a Special Report to the Commission pursuant to Specification 6.6.C within the next 30 days outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system to OPERABLE status.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.5.4 Each of the above required fire hose stations shown in Table 3.7.5.4-1 shall be demonstrated OPERABLE:

a. At least once per 31 days by a visual inspection of the fire hose stations accessible during plant operation to assure all required equipment is at the station.

b. At least once per 18 months by:

   1. Visual inspection of the fire hose stations not accessible during plant operation to assure all required equipment is at the station.
   2. Removing the hose for inspection and reracking, and
   3. Inspecting all gaskets and replacing any degraded gaskets in the couplings.

c. At least once per 3 years by partially opening each hose station valve to verify valve OPERABILITY and no flow blockage.

d. Within 5 years and between 5 and 8 years after purchase date and at least every 2 years thereafter by conducting a hose hydrostatic test at a pressure of 150 psig or at least 50 psig above the maximum fire main operating pressure, whichever is greater.

3/4.7.6 FIRE RATED ASSEMBLIES

LIMITING CONDITION FOR OPERATION

3.7.6 All fire rated assemblies, including walls, floor/ceilings, cable tray enclosures and other fire barriers separating safety related fire areas or separating portions of redundant systems important to safe shutdown within a fire area, and all sealing devices in fire rated assembly penetrations (fire doors, fire windows, fire dampers, cable and piping penetration seals and ventilation seals) shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

a. With one or more of the above required fire rated assemblies and/or sealing devices inoperable, within one hour either establish a continuous fire watch on at least one side of the affected assembly(s) and/or device(s) or verify the OPERABILITY of fire detectors on at least one side of the inoperable assembly(s) and/or sealing device(s) and establish an hourly fire watch patrol. Restore the inoperable fire rated assembly(s) and/or sealing device(s) to OPERABLE status within 7 days or, in lieu of any other report required by Specification 6.6.B, prepare and submit a Special Report to the Commission pursuant to Specification 6.6.C within the next 30 days outlining the action taken, the cause of the inoperable fire rated assembly(s) and/or sealing device(s) and plans and schedule for restoring the fire rated assembly(s) and/or sealing device(s) to OPERABLE status.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.6.1 Each of the above required fire rated assemblies and sealing devices shall be verified to be OPERABLE at least once per 18 months by performing a visual inspection of:

a. The exposed surfaces of each fire rated assemblies.

b. Each fire window/fire damper and associated hardware.

c. At least 10 percent of each type of sealed penetration. If apparent changes in appearance or abnormal degradations are found, a visual inspection of an additional 10 percent of each type of sealed penetration shall be made. This inspection process shall continue until a 10 percent sample with no apparent changes in appearance or abnormal degradation is found.

3/4.7.7 AREA TEMPERATURE MONITORING

LIMITING CONDITION FOR OPERATION

3.7.7 The temperature of each area of Unit 1 and Unit 2 shown in Table 3.7.7-1 shall be maintained within the limits indicated in Table 3.7.7-1.

APPLICABILITY: Whenever the equipment in an affected area is required to be OPERABLE.

ACTION:

With one or more areas exceeding the temperature limit(s) shown in Table 3.7.7-1:

a. For more than 8 hours, in lieu of any report required by Specification 6.6.B, prepare and submit a Special Report to the Commission pursuant to Specification 6.6.C within the next 30 days providing a record of the amount by which and the cumulative time the temperature in the affected area exceeded its limit and an analysis to demonstrate the continued OPERABILITY of the affected equipment.

b. By more than 30°F, in addition to the Special Report required above, within 4 hours either restore the area to within its temperature limit or declare the equipment in the affected area inoperable.

SURVEILLANCE REQUIREMENTS

4.7.7 The temperature in each of the above required areas shown in Table 3.7.7-1 shall be determined to be within its limit at least once per 24 hours.

TABLE 3.7.7-1

AREA TEMPERATURE MONITORING

AREA	TEMPERATURE LIMIT (°F)
A. Unit 1 Area Temperature Monitoring	
1. Control Room	50-104
2. Auxiliary Electric Equipment Room	50-104
3. Diesel Generator Room	50-122
4. Switchgear Room	50-104
5. HPCS, LPCS, RHR & RCIC Rooms	50-150
6. Primary Containment	
a. Drywell	50-150
b. Beneath Reactor Pressure Vessel	50-185
B. Unit 2 Area Temperature Monitoring Required For Unit 1	
1. Auxiliary Electric Equipment Room	50-104
2. Diesel Generator 2A Room	50-122
3. Division 1 and 2 Switchgear Rooms	50-104

3/4.7.9 SNUBBERS

LIMITING CONDITION FOR OPERATION

3.7.9 All hydraulic and mechanical snubbers shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3, and OPERATIONAL CONDITIONS 4 and 5 for snubbers located on systems required OPERABLE in those OPERATIONAL CONDITIONS.

ACTION:

With one or more snubbers inoperable, on any system, within 72 hours replace or restore the inoperable snubber(s) to OPERABLE status and perform an engineering evaluation per Specification 4.7.9g. on the attached component or declare the attached system inoperable and follow the appropriate ACTION statement for that system.

SURVEILLANCE REQUIREMENTS

4.7.9 Each snubber shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program and the requirements of Specification 4.0.5.

a. Inspection Types

As used in this specification, type of snubber shall mean snubbers of the same design and manufacturer, irrespective of capacity.

b. Visual Inspections

Snubbers are categorized as inaccessible or accessible during reactor operation. Each of these groups (inaccessible and accessible) may be inspected independently according to the schedule below. The first inservice visual inspection of each type of snubber shall be performed after 4 months but within 10 months of commencing POWER OPERATION and shall include all hydraulic and mechanical snubbers. If all snubbers of each type on any system are found OPERABLE during the first inservice visual inspection, the second inservice visual inspection of that system shall be performed at the first refueling outage. Otherwise, subsequent visual inspections of a given system shall be performed in accordance with the following schedule:

No. Inoperable Snubbers of Each Type On Any System per Inspection Period	Subsequent Visual Inspection Period*#
0	18 months ± 25%
1	12 months ± 25%
2	6 months ± 25%
3, 4	124 days ± 25%
5, 6, 7	62 days ± 25%
8 or more	31 days ± 25%

*The inspection interval for each type of snubber on a given system shall not be lengthened more than one step at a time unless a generic problem as been identified and corrected; in that event the inspection interval may be lengthened one step the first time and two steps thereafter if no inoperable snubbers of that type are found on that system.

#The provisions of Specification 4.0.2 are not applicable.

c. Visual Inspection Acceptance Criteria

Visual inspections shall verify that: there are no visible indications of damage or impaired OPERABILITY and (2) attachments to the foundation or supporting structure are secure, and (3) fasteners for attachment of the snubber to the component and to the snubber anchorage are secure. Snubbers which appear inoperable as a result of visual inspections may be determined OPERABLE for the purpose of establishing the next visual inspection interval, provided that: (1) the cause of the rejection is clearly established and remedied for that particular snubber and for other snubbers irrespective of type on that system that may be generically susceptible; and (2) the affected snubber is functionally tested in the as-found condition and determined OPERABLE per Specification 4.7.9f. All snubbers connected to an inoperable common hydraulic fluid reservoir shall be counted as inoperable snubbers. For those snubbers common to more than one system, the OPERABILITY of such snubbers shall be considered in assessing the surveillance schedule for each of the related systems.

d. Transient Event Inspection

An inspection shall be performed of all hydralic and mechanical snubbers attached to sections of systems that have experienced unexpected, potentially damaging transients as determined from a review of operational data and a visual inspection of the systems within 6 months following such an event. In addition to satisfying the visual inspection acceptance criteria, freedom-of-motion of mechanical snubbers shall be verified using at least one of the following: (1) manually induced snubber movement; or (2) evaluation of in-place snubber piston setting; or (3) stroking the mechanical snubber through its full range of travel.

e. Functional Tests

During the first refueling shutdown and at least once per 18 months thereafter during shutdown, a representative sample of snubbers shall be tested using one of the following sample plans. The sample plan shall be selected prior to the test period and cannot be changed during the test period. The NRC Regional Administrator shall be notified in writing of the sample plan selected prior to the test period or the sample plan used in the prior test period shall be implemented:

1) At least 10% of the total of each type of snubber shall be functionally tested either in-place or in a bench test. For each snubber of a type that does not meet the functional test acceptance criteria of Specification 4.7.9f., an additional 10% of that type of snubber shall be functionally tested until no more failures are found or until all snubbers of that type have been functionally tested; or

2) A representative sample of each type of snubber shall be functionally tested, in accordance with Figure 4.7-1. "C" is the

SURVEILLANCE REQUIREMENTS (Continued)

e. Functional Tests (continued)

total number of snubbers of a type found not meeting the acceptance requirements of Specification 4.7.9f. The cumulative number of snubbers of a type tested is denoted by "N". At the end of each day's testing, the new values of "N" and "C" (previous day's total plus current day's increments) shall be plotted on Figure 4.7-1. If at any time the point plotted falls in the "Reject" region, all snubbers of that type may be functionally tested. If at any time the point plotted falls in the "Accept" region, testing of snubbers of that type may be terminated. When the point plotted lies in the "Continue Testing" region, additional snubbers of that type may be terminated. When the point plotted lies in the "Continue Testing" region, additional snubbers of that type shall be tested until the point falls in the "Accept" region or the "Reject" region, or all the snubbers of that type have been tested. Testing equipment failure during functional testing may invalidate that day's testing and allow that day's testing to resume anew at a later time provided all snubbers tested with the failed equipment during the day of equipment failure are retested; or

3) An initial representative sample of 55 snubbers shall be functionally tested. For each snubber type which does not meet the functional test acceptance criteria, another sample of at least one-half the size of the initial sample shall be tested until the total number tested is equal to the initial sample size multiplied by the factor, $1 + C/2$, where "C" is the number of snubbers found which do not meet the functional test acceptance criteria. The results from this sample plan shall be plotted using an "Accept" line which follows the equation $N = 55(1 + C/2)$. Each snubber point should be plotted as soon as the snubber is tested. If the point plotted falls on or below the "Accept" line, testing of that type of snubber may be terminated. If the point plotted falls above the "Accept" line, testing must continue until the point falls in the "Accept" region or all the snubbers of that type have been tested.

The representative sample selected for the functional testing sample plans shall be randomly selected from the snubbers of each type and reviewed before beginning the testing. The review shall ensure, as far as practicable, that they are representative of the various configurations, operating environments, range of size, and capacity of snubbers of each type. Snubbers placed in the same location as snubbers which failed the previous functional test shall be retested at the time of the next functional test but shall not be included in the sample plan. If during the functional testing, additional sampling is required due to failure of only one type of snubber, the functional test results shall be reviewed at that time to determine if additional samples should be limited to the type of snubber which has failed the functional testing.

SURVEILLANCE REQUIREMENTS (Continued)

f. Functional Testing Acceptance Criteria

The snubber functional test shall verify that:

1) Activation (restraining action) is achieved within the specified range in both tension and compression;

2) Snubber bleed, or release rate where required, is present in both tension and compression, within the specified range;

3) Where required, the force required to initiate or maintain motion of the snubber is within the specified range in both directions of travel; and

4) For snubbers specifically required not to displace under continuous load, the ability of the snubber to withstand load without displacement.

Testing methods may be used to measure parameters indirectly or parameters other than those specified if those results can be correlated to the specified parameters through established methods.

g. Functional Test Failure Analysis

An engineering evaluation shall be made of each failure to meet the functional test acceptance criteria to determine the cause of the failure. The results of this evaluation shall be used, if applicable, in selecting snubbers to be tested in an effort to determine the OPERABILITY of other snubbers irrespective of type which may be subject to the same failure mode.

For the snubbers found inoperable, an engineering evaluation shall be performed on the components to which the inoperable snubbers are attached. The purpose of this engineering evaluation shall be to determine if the components to which the inoperable snubbers are attached were adversely affected by the inoperability of the snubbers in order to ensure that the component remains capable of meeting the designed service.

If any snubber selected for functional testing either fails to lock up or fails to move, i.e., frozen in place, the cause will be evaluated and, if caused by manufacturer or design deficiency, all snubbers of the same type subject to the same defect shall be functionally tested. This testing requirement shall be independent of the requirements stated in Specification 4.7.9e. for snubbers not meeting the functional test acceptance criteria.

h. Functional Testing of Repaired and Replaced Snubbers

Snubbers which fail the visual inspection or the functional test acceptance criteria shall be repaired or replaced. Replacement

SURVEILLANCE REQUIREMENTS (Continued)

h. Functional Testing of Repaired and Replaced Snubbers (Continued)

snubbers and snubbers which have repairs which might affect the functional test results shall be tested to meet the functional test criteria before installation in the unit. Mechanical snubbers shall have met the acceptance criteria subsequent to their most recent service, and the freedom-of-motion test must have been performed within 12 months before being installed in the unit.

i. Snubber Service Life Program

The service life of hydraulic and mechanical snubbers shall be monitored to ensure that the service life is not exceeded between surveillance inspections. The maximum expected service life for various seals, springs, and other critical parts shall be determined and established based on engineering information and shall be extended or shortened based on monitored test results and failure history. Critical parts shall be replaced so that the maximum service life will not be exceeded during a period when the snubber is required to be OPERABLE. The parts replacements shall be documented and the documentation shall be retained in accordance with Specification 6.5B.

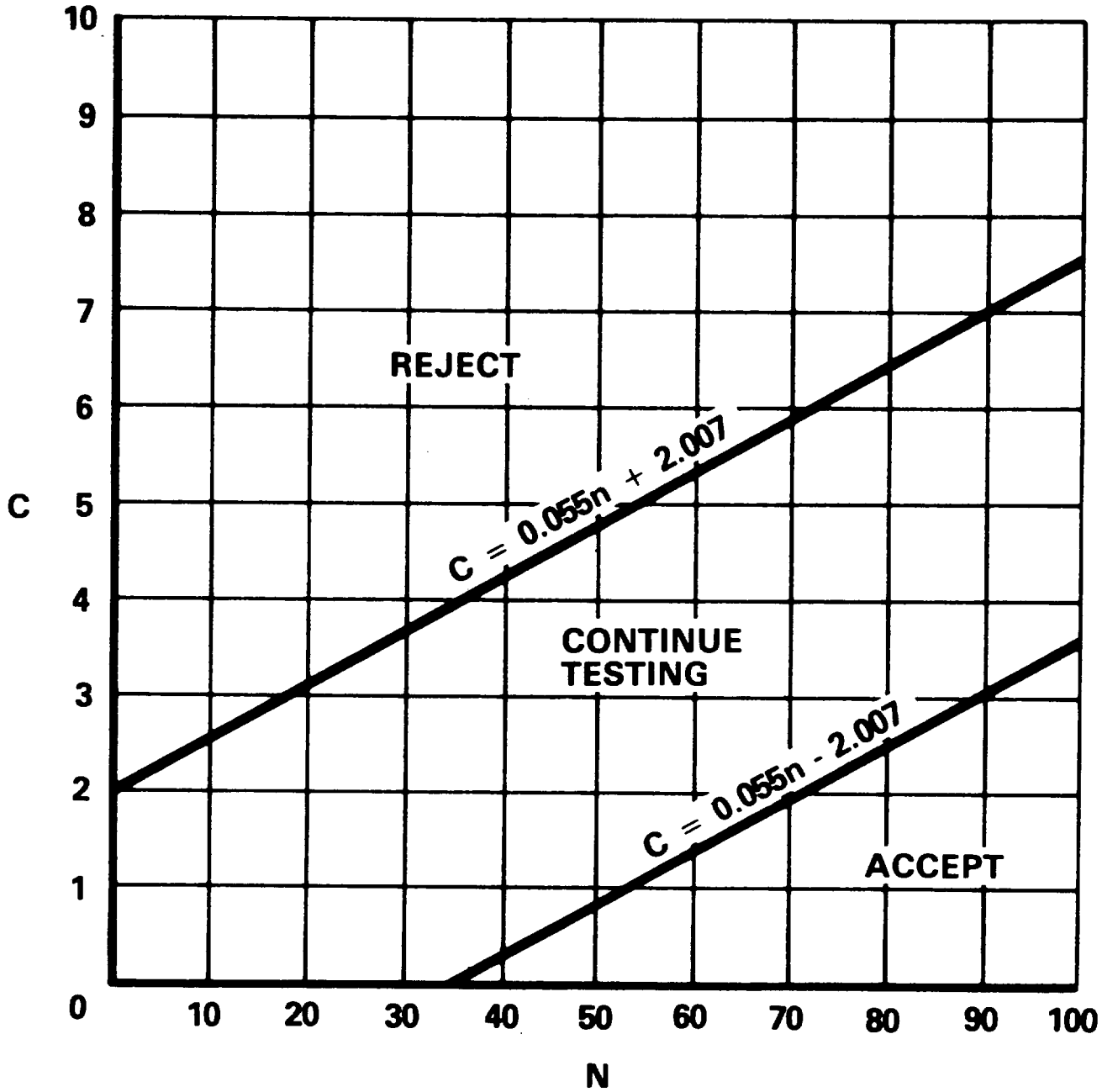


FIGURE 4.7-1

SAMPLING PLAN FOR SNUBBER FUNCTIONAL TEST

3/4.7.10 MAIN TURBINE BYPASS SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.10 The main turbine bypass system shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION: With the main turbine bypass system inoperable, within 2 hours restore the system to OPERABLE status or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.7.10 The main turbine bypass system shall be demonstrated OPERABLE at least once per:

a. 7 days by cycling each turbine bypass valve through at least one complete cycle of full travel.

b. 18 months by:

1. Performing a system functional test which includes simulated automatic actuation and verifying that each automatic valve actuates to its correct position.

2. Demonstrating TURBINE BYPASS SYSTEM RESPONSE TIME to be less than or equal to 200 milliseconds

3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1 A.C. SOURCES

A.C. SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.1.1 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system, and

b. Separate and independent diesel generators 0, 1A, 2A and 1B with:

   1. For diesel generator 0, 1A and 2A:

      a) A separate day fuel tank containing a minimum of 250 gallons of fuel.

      b) A separate fuel storage system containing a minimum of 31,000 gallons of fuel.

   2. For diesel generator 1B, a separate fuel storage tank/day tank containing a minimum of 29,750 gallons of fuel.

   3. A separate fuel transfer pump.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With either one offsite circuit or diesel generator 0 or 1A of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirements 4.8.1.1.1a within 1 hour, and 4.8.1.1.2a.4, for one diesel generator at a time, within eight hours, and at least once per 8 hours thereafter; restore at least two offsite circuits and diesel generators 0 and 1A to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one offsite circuit and diesel generator 0 or 1A of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirements 4.8.1.1.1a within 1 hour, and 4.8.1.1.2a.4, for one diesel generator at a time, within six hours, and at least once per 8 hours thereafter; restore at least one of the inoperable A.C. sources to OPERABLE status within 12 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. Restore at least two offsite circuits and diesel generators 0 and 1A to OPERABLE status within 72 hours from the time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION (Continued)

c. With both of the above required offsite circuits inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.2a.4, for one diesel generator at a time, within eight hours, and at least once per 8 hours thereafter, unless the diesel generators are already operating; restore at least one of the inoperable offsite circuits to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours. With only one offsite circuit restored to OPERABLE status, restore at least two offsite circuits to OPERABLE status within 72 hours from time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

d. With diesel generators 0 and 1A of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirements 4.8.1.1.1a within 1 hour and 4.8.1.1.2a.4, for one diesel generator at a time, within four hours and at least once per 8 hours thereafter; restore at least one of the inoperable diesel generators 0 and 1A to OPERABLE status within 2 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. Restore both diesel generators 0 and 1A to OPERABLE status within 72 hours from time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

e. With diesel generator 1B of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirements 4.8.1.1.1a within 1 hour, and 4.8.1.1.2a.4, for one diesel generator at a time, within six hours, and at least once per 8 hours thereafter; restore the inoperable diesel generator 1B to OPERABLE status within 72 hours or declare the HPCS system inoperable and take the ACTION required by Specification 3.5.1.

f. With diesel generator 2A of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirements 4.8.1.1.1a and 4.8.1.1.2.a4, for diesel generator 1A, within one hour, and at least once per 8 hours thereafter; restore the inoperable diesel generator 2A to OPERABLE status within 72 hours or declare standby gas treatment system subsystem B, Unit 2 drywell and suppression chamber hydrogen recombiner system, and control room and auxiliary electric equipment room emergency filtration system train B inoperable and take the ACTION required by Specifications 3.6.5.3, 3.6.6.1., and 3.7.2; continued performance of Surveillance Requirements 4.8.1.1.1a. and 4.8.1.1.2a.4 for diesel generator 1A is not required provided the above systems are delcared inoperable and the ACTION of their respective specifications is taken.

SURVEILLANCE REQUIREMENTS (Continued)

d. At least once per 18 months during shutdown by:

1. Subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for this class of standby service.

2. Verifying the diesel generator capability to reject a load of greater than or equal to 1190 kw for diesel generator 0, greater than or equal to 638 kw for diesel generators 1A and 2A, and greater than or equal to 2381 kw for diesel generator 1B while maintaining engine speed less than or equal to 75% of the difference between nominal speed and the overspeed trip setpoint or 15% above nominal, whichever is less.

3. Verifying the diesel generator capability to reject a load of 2600 kw without tripping. The generator voltage shall not exceed 5000 volts during and following the load rejection.

4. Simulating a loss of offsite power by itself, and:

   a) For Divisions 1 and 2 and for Unit 2 Division 2:

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

      2) Verifying the diesel generator starts on the auto-start signal, energizes the emergency busses with permanently connected loads within 13 seconds, energizes the auto-connected loads and operates for greater than or equal to 5 minutes while its generator is so loaded. After energization, the steady state voltage and frequency of the emergency busses shall be maintained at 4160 ± 150 volts and 60 ± 1.2 Hz during this test.

   b) For Division 3:

      1) Verifying de-energization of the emergency bus.

      2) Verifying the diesel generator starts on the auto-start signal, energizes the emergency bus with its loads within 13 seconds and operates for greater than or equal to 5 minutes while its generator is so loaded. After energization, the steady state voltage and frequency of the emergency bus shall be maintained at 4160 ± 150 volts and 60 ± 1.2 Hz during this test.

5. Verifying that on an ECCS actuation test signal, without loss of offsite power, diesel generators 0, 1A and 1B start on the auto-start signal and operate on standby for greater than or equal to 5 minutes. The generator voltage and frequency shall be 4160 + 416, -150 volts and 60 + 3.0, -1.2 Hz within 13 seconds after the auto-start signal; the steady state generator voltage and frequency shall be maintained within these limits during this test.

6. Simulating a loss of offsite power in conjunction with an ECCS actuation test signal, and:

   a) For Divisions 1 and 2:

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

      2) Verifying the diesel generator starts on the auto-start signal, energizes the emergency busses with permanently connected loads within 13 seconds, energizes the auto-connected emergency loads through the load sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After energization, the steady state voltage and frequency of the emergency busses shall be maintained at 4160 ± 416 volts and 60 ± 1.2 Hz during this test.

   b) For Division 3:

      1) Verifying de-energization of the emergency bus.

      2) Verifying the diesel generator starts on the auto-start signal, energizes the emergency bus with its loads within 13 seconds and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After energization, the steady state voltage and frequency of the emergency bus shall be maintained at 4160 ± 416 volts and 60 ± 1.2 Hz during this test.

7. Verifying that all diesel generator 0, 1A and 1B automatic trips except the following are automatically bypassed on an ECCS actuation signal:

   a) For Divisions 1 and 2 - engine overspeed, generator differential current, and emergency manual stop.

   b) For Division 3 - engine overspeed, generator differential or overcurrent, and emergency manual stop.

8. Verifying the diesel generator operates for at least 24 hours. During the first 2 hours of this test, the diesel generator shall be loaded to greater than or equal to 2860 kw and during the remaining 22 hours of this test, the diesel generator shall be loaded to 2600 kw. The generator voltage and frequency shall be 4160 + 420, -150 volts and 60 + 3.0, -1.2 Hz within 13 seconds after the start signal; the steady state generator voltage and frequency shall be maintained within these limits during this test. Within 5 minutes after completing this 24 hour test, perform Surveillance Requirement 4.8.1.1.2.d.4.a).2) and b).2).*

SURVEILLANCE REQUIREMENTS (Continued)

9. Verifying that the auto-connected loads to each diesel generator do not exceed the 2000 hour rating of 2860 kW.

10. Verifying the diesel generator's capability to:

    a) Synchronize with the offsite power source while the generator is loaded with its emergency loads upon a simulated restoration of offsite power,

    b) Transfer its loads to the offsite power source, and

    c) Be restored to its standby status.

11. Verifying that with diesel generator 0, 1A and 1B operating in a test mode and connected to its bus:

    a) For Divisions 1 and 2, that a simulated ECCS actuation signal overrides the test mode by returning the diesel generator to standby operation.

    b) For Division 3, that a simulated trip of the diesel generator overcurrent relay trips the SAT feed breaker to bus 143 and that the diesel generator continues to supply normal bus loads.

12. Verifying that the automatic load sequence timer is OPERABLE with the interval between each load block within ± 10% of its design interval for diesel generators 0 and 1A.

13. Verifying that the following diesel generator lockout features prevent diesel generator operation only when required:

    a) Generator underfrequency.

    b) Low lube oil pressure.

    c) High jacket cooling temperature

    d) Generator reverse power.

    e) Generator overcurrent.

    f) Generator loss of field.

    g) Engine cranking lockout.

*If Surveillance Requirement 4.8.1.1.2.d.4a)2) and/or b)2) are not satisfactorily completed, it is not necessary to repeat the preceding 24 hour test. Instead, the diesel generator may be operated at 2600 kW for 1 hour or until operating temperature has stabilized.

SURVEILLANCE REQUIREMENTS (Continued)

e. At least once per 10 years or after any modifications which could affect diesel generator interdependence by starting diesel generators 0, 1A and 1B simultaneously, during shutdown, and verifying that all three diesel generators accelerate to 900 rpm + 5, -2% in less than or equal to 13 seconds.

f. At least once per 10 years by:

1. Draining each fuel oil storage tank, removing the accumulated sediment and cleaning the tank using a sodium hypochlorite or equivalent solution, and

2. Performing a pressure test of those portions of the diesel fuel oil system designed to Section III, subsection ND, of the ASME Code in accordance with ASME Code Section 11, Article IWD-5000.

4.8.1.1.3 Reports - All diesel generator failures, valid or non-valid, shall be reported to the Commission pursuant to Specification 6.6.B. Reports of diesel generator failures shall include the information recommended in Regulatory Position C.3.b of Regulatory Guide 1.108, Revision 1, August 1977. If the number of failures in the last 100 valid tests, on a per nuclear unit basis, is greater than or equal to 7, the report shall be supplemented to include the additional information recommended in Regulatory Position c.3.b of Regulatory Guide 1.108, Revision 1, August 1977.

TABLE 4.8.1.1.2-1

DIESEL GENERATOR TEST SCHEDULE

Number of Failures in Last 100 Valid Tests*	Test Frequency
≤ 1	At least once per 31 days
2	At least once per 14 days
3	At least once per 7 days
≥ 4	At least once per 3 days

*Criteria for determining number of failures and number of valid tests shall be in accordance with Regulatory Position C.2.e of Regulatory Guide 1.108, Revision 1, August 1977, where the last 100 tests are determined on a per nuclear unit basis. With the exception of the semi-annual fast start, no starting time requirements are required to meet the valid test requirements of Regulatory Guide 1.108.

LIMITING CONDITION FOR OPERATION

3.8.1.2 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. One circuit between the offsite transmission network and the onsite Class IE distribution system, and

b. Diesel generator 0 or 1A, and diesel generator 1B when the HPCS system is required to be OPERABLE, and diesel generator 2A when the offsite power source for standby gas treatment system subsystem B or control room and auxiliary electric equipment room emergency filtration system train B is inoperable and either or both systems are required to be OPERABLE, with each diesel generator having:

   1. For diesel generator 0, 1A and 2A:

      a) A separate day fuel tank containing a minimum of 250 gallons of fuel.

      b) A separate fuel storage system containing a minimum of 31,000 gallons of fuel.

   2. For diesel generator 1B, a separate fuel storage tank/day tank containing a minimum of 29,750 gallons of fuel.

   3. A fuel transfer pump.

APPLICABILITY: OPERATIONAL CONDITIONS 4, 5, and *.

ACTION:

a. With all offsite circuits inoperable and/or with diesel generators 0 or 1A inoperable, suspend CORE ALTERATIONS, handling of irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel.

b. With diesel generator 1B inoperable, restore the inoperable diesel generator 1B to OPERABLE status within 72 hours or declare the HPCS system inoperable and take the ACTION required by Specification 3.5.2 and 3.5.3.

*When handling irradiated fuel in the secondary containment.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

c. With diesel generator 2A inoperable, declare standby gas treatment system subsystem B and control room and auxiliary electric equipment room emergency filtration system train B inoperable and take the ACTION required by Specifications 3.6.5.3 and 3.7.2.

d. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.8.1.2 At least the above required A.C. electrical power sources shall be demonstrated OPERABLE per Surveillance Requirements 4.8.1.1.1; 4.8.1.1.2 and 4.8.1.1.3, except for the requirement of 4.8.1.1.2.a.5.

3/4.8.2 ONSITE POWER DISTRIBUTION SYSTEMS

A. C. DISTRIBUTION - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.2.1 The following A.C. distribution system electrical divisions shall be OPERABLE and energized:

a. Division 1, consisting of;

1. 4160 volt bus 141Y.
2. 480 volt buses 135X and 135Y.
3. 480 volt MCCs 135X-1, 135X-2, 135X-3, 135Y-1 and 135Y-2.
4. 120 volt A.C. distribution panels in 480 volt MCCs 135X-1, 135X-2, 135X-3 and 135Y-1.

b. Division 2, consisting of;

1. 4160 volt bus 142Y.
2. 480 volt buses 136X and 136Y.
3. 480 volt MCCs 136X-1, 136X-2, 136X-3, 136Y-1 and 136Y-2.
4. 120 volt A.C. distribution panels in 480 volt MCCs 136X-1, 136X-2, 136X-3 and 136Y-2.

c. Division 3, consisting of;

1. 4160 volt bus 143.
2. 480 volt MCC 143-1.
3. 120 volt A.C. distribution panels in 480 volt MCC 143-1.

d. Unit 2 Division 1, consisting of;

1. 4160 volt bus 241Y.
2. Breaker 2414 OPERABLE or closed.

e. Unit 2 Division 2, consisting of;

1. 4160 volt bus 242Y.
2. 480 volt buses 236X and 236Y.
3. 480 volt MCCs 236X-1, 236X-2, 236X-3, 236Y-1, and 236Y-2.
4. 120 volt A.C. distribution panels in 480 volt MCCs 236X-1, 236X-2, 236X-3, and 236Y-2.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

LIMITING CONDITION FOR OPERATION

3.8.2.2 As a minimum, Division 1 or Division 2, and Division 3 when the HPCS system is required to be OPERABLE, and Unit 2 Division 2 when the standby gas treatment system and/or the control room and auxiliary electric equipment room emergency filtration system are required to be OPERABLE, of the A.C. distribution system shall be OPERABLE and energized with:

a. Division 1, consisting of;

   1. 4160 volt bus 141Y.
   2. 480 volt buses 135X and 135Y.
   3. 480 volt MCCs 135X-1, 135X-2, 135X-3, 135Y-1 and 135Y-2.
   4. 120 volt A.C. distribution panels in 480 volt MCCs 135X-1, 135X-2, 135X-3 and 135Y-1.

b. Division 2, consisting of;

   1. 4160 volt bus 142Y.
   2. 480 volt buses 136X and 136Y.
   3. 480 volt MCCs 136X-1, 136X-2, 136X-3, 136Y-1 and 136Y-2.
   4. 120 volt A.C. distribution panels in 480 volt MCCs 136 X-1, 136X-2, 136X-3 and 136Y-2.

c. Division 3, consisting of;

   1. 4160 volt bus 143
   2. 480 volt MCC 143-1.
   3. 120 volt A.C. distribution panels in 480 volt MCC 143-1.

d. Unit 2 Division 2, consisting of;

   1. 4160 volt bus 242Y.
   2. 480 volt buses 236X and 236Y.
   3. 480 volt MCCs 236X-1, 236X-2, 236X-3, and 236Y-1.
   4. 120 volt A.C. distribution panels in 480 volt MCCs 236X-1, 236X-2, and 236X-3.

APPLICABILITY: OPERATIONAL CONDITIONS 4, 5, and *.

*When handling irradiated fuel in the secondary containment.

LIMITING CONDITION FOR OPERATION

3.8.2.3 The following D.C. distribution system electrical divisions shall be OPERABLE and energized:

a. Division 1, consisting of;
   1. 125 volt battery 1A.
   2. 125 volt full capacity charger.
   3. 125 volt distribution panel 111Y.

b. Division 2, consisting of;
   1. 125 volt battery 1B.
   2. 125 volt full capacity charger.
   3. 125 volt distribution panel 112Y.

c. Division 3, consisting of;
   1. 125 volt battery 1C.
   2. 125 volt full capacity charger.
   3. 125 volt distribution panel 113.

d. Unit 2 Division 2, consisting of;
   1. 125 volt battery 2B.
   2. 125 volt full capacity charger.
   3. 125 volt distribution panel 212Y.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With either Division 1 or Division 2 inoperable or not energized, restore the inoperable division to OPERABLE and energized status within 2 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With Division 3 inoperable or not energized, declare the HPCS system inoperable and take the ACTION required by Specification 3.5.1.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

c. With Unit 2 Division 2 inoperable or not energized, restore the inoperable division to OPERABLE and energized status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.8.2.3.1 Each of the above required D.C. distribution system electrical divisions shall be determined OPERABLE and energized at least once per 7 days by verifying correct breaker alignment, indicated power availability from the charger and battery, and voltage on the panel with an overall voltage of greater than or equal to 125 volts.

4.8.2.3.2 Each 125-volt battery and charger shall be demonstrated OPERABLE:

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

1. The parameters in Table 4.8.2.3.2-1 meet the Category A limits, and

2. Total battery terminal voltage is greater than or equal to 128 volts on float charge.

SURVEILLANCE REQUIREMENTS (Continued)

b. At least once per 92 days and within 7 days after a battery discharge with battery voltage below 110 volts, or battery overcharge with battery terminal voltage above 150 volts, by verifying that:

1. The parameters in Table 4.8.2.3.2-1 meet the Category B limits,

2. There is no visible corrosion at either terminals or connectors, or the connection resistance of these items is less than 150 x 10^{-6} ohm, and

3. The average electrolyte temperature of at least 10 connected cells is above 60°F.

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

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

2. The cell-to-cell and terminal connections are clean, tight, free of corrosion and coated with anti-corrosion material,

3. The resistance of each cell and terminal connection is less than or equal to 150 x 10^{-6} ohm, and

4. The battery charger will supply at least 200 amperes for division 1, 75 amperes for division 2 and 50 amperes for division 3 at a minimum of 130 volts for at least 8 hours.

d. At least once per 18 months, during shutdown, by verifying that either:

1. The battery capacity is adequate to supply and maintain in OPERABLE status all of the actual emergency loads for the design cycle when the battery is subjected to a battery service test, or

2. The battery capacity is adequate to supply a dummy load, which is verified to be greater than the actual emergency load, of the following profile while maintaining the battery terminal voltage greater than or equal to 105 volts.

a) Division 1, greater than or equal to:

1) 483.4 amperes for the first 60 seconds,
2) 251.2 amperes for the next 14 minutes,
3) 227.7 amperes for the next 15 minutes,
4) 151.7 amperes for the next 30 minutes, and
5) 83.7 amperes for the last 180 minutes.

SURVEILLANCE REQUIREMENTS (Continued)

b) Division 2, greater than or equal to:

1) 488.5 amperes for the first 60 seconds,
2) 237.6 amperes for the next 14 minutes,
3) 177.6 amperes for the next 15 minutes, and
4) 141.6 amperes for the next 30 minutes, and
5) 54.4 amperes for the last 180 minutes.

c) Division 3, greater than or equal to:

1) 58.4 amperes for the first 60 seconds,
2) 11.1 amperes for the next 239 minutes.

d) Unit 2 Division 2, greater than or equal to:

1) 488.5 amperes for the first 60 seconds,
2) 237.6 amperes for the next 14 minutes,
3) 177.6 amperes for the next 15 minutes,
4) 141.6 amperes for the next 30 minutes, and
5) 54.4 amperes for the last 180 minutes.

e. At least once per 60 months, during shutdown, by verifying that the battery capacity is at least 80% of the manufacturers rating when subjected to a performance discharge test. Once per 60 month interval, this performance discharge test may be performed in lieu of the battery service test.

f. Annual performance discharge tests of battery capacity shall be given to any battery that shows signs of degradation or has reached 85% of the service life expected for the application. Degradation is indicated when the battery capacity drops more than 10% of rated capacity from its average on previous performance tests, or is below 90% of the manufacturer's rating.

D.C. DISTRIBUTION - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.2.4 As a minimum, Division 1 or Division 2, and Division 3 when the HPCS system is required to be OPERABLE, and Unit 2 Division 2 when the standby gas treatment system and/or the control room and auxiliary electric equipment room emergency filtration system are required to be OPERABLE, of the D.C. distribution system shall be OPERABLE and energized with:

a. Division 1, consisting of;

   1. 125 volt battery 1A.
   2. 125 volt full capacity charger.
   3. 125 volt distribution panel 111Y.

b. Division 2, consisting of;

   1. 125 volt battery 1B.
   2. 125 volt full capacity charger.
   3. 125 volt distribution panel 112Y.

c. Division 3, consisting of;

   1. 125 volt battery 1C.
   2. 125 volt full capacity charger.
   3. 125 volt distribution panel 113.

d. Unit 2 Division 2, consisting of;

   1. 125 volt battery 2B.
   2. 125 volt full capacity charger.
   3. 125 volt distribution panel 212Y.

APPLICABILITY: OPERATIONAL CONDITIONS 4, 5, and *.

ACTION:

a. With both Division 1 distribution panel 111Y and Division 2 distribution panel 112Y of the above required D.C. distribution system inoperable or not energized, suspend CORE ALTERATIONS, handling of irradiated fuel cask in the secondary containment and operations with a potential for draining the reactor vessel.

b. With Division 3 distribution panel 113 of the above required D.C. distribution system inoperable or not energized, declare the HPCS system inoperable and take the ACTION required by Specifications 3.5.2 and 3.5.3.

*When handling irradiated fuel in the secondary containment.

3/4.8.3 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

A.C. CIRCUITS INSIDE PRIMARY CONTAINMENT

LIMITING CONDITION FOR OPERATION

3.8.3.1 At least the following A.C. circuits inside primary containment shall be de-energized*:

a. Installed welding grid systems 1A and 1B, and

b. All drywell lighting circuits.

c. All drywell hoists and cranes circuits.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

With any of the above required circuits energized, trip the associated circuit breaker(s) in the specified panel(s) within 1 hour.

SURVEILLANCE REQUIREMENTS

4.8.3.1 Each of the above required A.C. circuits shall be determined to be de-energized at least once per 24 hours** by verifying that the associated circuit breakers are in the tripped condition.

*Except during entry into the drywell.

**Except at least once per 31 days if locked, sealed or otherwise secured in the tripped condition.

TABLE 3.8.3.2-1

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

DEVICE NUMBER AND LOCATION	TRIP SETPOINT (Amperes)	RESPONSE TIME (Milliseconds/Cycles)[a]	SYSTEM/ COMPONENT POWERED
a. 6.9 KV Circuit Breakers			
1. Swgr. 151 (Compt. 4)	840[c]	83.3/5	RR Pump 1A
2. Swgr. 152 (Compt. 4)	840[c]	83.3/5	RR Pump 1B
3. Swgr. 151-1 (Bkr. 2A)	720[b]	83.3/5	RR Pump 1A, low speed
4. Swgr. 152-1 (Bkr. 2B)	720[b]	83.3/5	RR Pump 1B, low speed
b. 480 VAC Circuit Breakers			
1. Swgr. 136Y (Compt. 403C)	160[c]	50/3	VP/Pri. Cont. Vent Supply Fan 1B
2. Swgr. 135Y (Compt. 203A)	160[c]	50/3	VP/Pri. Cont. Vent Supply Fan 1A
c. 480 VAC (Molded Case) Circuit Breakers			
1. Type K-M Cat # NZ MH-160/ZM6C			
a) MCC 136Y-2 (Compt. C4)	174	N.A.	RR/MOV 1B33-F067B
b) MCC 136Y-2 (Compt. A3)	72	N.A.	RR/MOV 1B33-F023B
c) MCC 134X-1 (Compt. B3)	10	N.A.	NB/MOV1 1B21-F001
d) MCC 134X-1 (Compt. B4)	10	N.A.	NB/MOV 1B21-F002

MOTOR OPERATED VALVES THERMAL OVERLOAD PROTECTION

LIMITING CONDITION FOR OPERATION

3.8.3.3 The thermal overload protection of each valve shown in Table 3.8.4.2-1 shall be bypassed continuously or under accident conditions, as applicable, by an OPERABLE bypass device integral with the motor starter.

APPLICABILITY: Whenever the motor operated valve is required to be OPERABLE.

ACTION:

b. With the thermal overload protection for one or more of the above required valves not bypassed continuously or under accident conditions, as applicable, by an OPERABLE integral bypass device, take administrative action to continuously bypass the thermal overload within 8 hours or declare the affected valve(s) inoperable and apply the appropriate ACTION statement(s) for the affected system(s).

b. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.8.3.3.1 The thermal overload protection for the above required valves shall be verified to be bypassed continuously or under accident conditions, as applicable, by an OPERABLE integral bypass device by the performance of a CHANNEL FUNCTIONAL TEST of the bypass circuitry for those thermal overloads which are normally in force during plant operation and bypassed under accident conditions and by verifying that the thermal overload protection is bypassed for those thermal overloads which are continuously bypassed and temporarily placed in force only when the valve motors are undergoing periodic or maintenance testing:

a. At least once per 18 months, and

b. Following maintenance on the motor starter.

4.8.3.3.2 The thermal overload protection for the above required valves which are continuously bypassed shall be verified to be bypassed following testing during which the thermal overload protection was temporarily placed in force.

TABLE 3.8.3.3-1

MOTOR OPERATED VALVES THERMAL OVERLOAD PROTECTION

	VALVE NUMBER	BYPASS DEVICE (Continuous)(Accident Conditions)	SYSTEM(S) AFFECTED
a.	1VG001	Accident Conditions	SBGTS
	1VG003	Accident Conditions	
	2VG001	Accident Conditions	
	2VG003	Accident Conditions	
b.	1VP113A	Accident Conditions	Primary containment chilled water coolers
	1VP113B	Accident Conditions	
	1VP114A	Accident Conditions	
	1VP114B	Accident Conditions	
	1VP053A	Accident Conditions	
	1VP053B	Accident Conditions	
	1VP063A	Accident Conditions	
	1VP063B	Accident Conditions	
c.	1VQ040	Accident Conditions	Primary containment vent and purge system
	1VQ036	Accident Conditions	
	1VQ026	Accident Conditions	
	1VQ029	Accident Conditions	
	1VQ038	Accident Conditions	
	1VQ031	Accident Conditions	
	1VQ032	Accident Conditions	
	1VQ034	Accident Conditions	
	1VQ035	Accident Conditions	
	1VQ027	Accident Conditions	
	1VQ042	Accident Conditions	
	1VQ043	Accident Conditions	
	1VQ047	Accident Conditions	
	1VQ048	Accident Conditions	
	1VQ050	Accident Conditions	
	1VQ051	Accident Conditions	
	1VQ068	Accident Conditions	
	1VQ030	Accident Conditions	
	1VQ037	Accident Conditions	
d.	1WR179	Accident Conditions	RBCCW system
	1WR180	Accident Conditions	
	1WR040	Accident Conditions	
	1WR029	Accident Conditions	
e.	1B21 - F067A	Accident Conditions	Main steam system
	1B21 - F067B	Accident Conditions	
	1B21 - F067C	Accident Conditions	
	1B21 - F067D	Accident Conditions	
	1B21 - F019	Accident Conditions	
	1B21 - F016	Accident Conditions	

REACTOR PROTECTION SYSTEM ELECTRICAL POWER MONITORING

LIMITING CONDITION FOR OPERATION

3.8.3.4 Two RPS electric power monitoring assemblies for each inservice RPS MG set or alternate power supply shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

a. With one RPS electric power monitoring assembly for an inservice RPS MG set or alternate power supply inoperable, restore the inoperable power monitoring assembly to OPERABLE status within 72 hours or remove the associated RPS MG set or alternate power supply from service.

b. With both RPS electric power monitoring assemblies for an inservice RPS MG set or alternate power supply inoperable, restore at least one electric power monitoring assembly to OPERABLE status within 30 minutes or remove the associated RPS MG set or alternate power supply from service.

SURVEILLANCE REQUIREMENTS

4.8.3.4 The above specified RPS electric power monitoring assemblies shall be determined OPERABLE:

a. By performance of a CHANNEL FUNCTIONAL TEST each time the plant is in COLD SHUTDOWN for a period of more than 24 hours, unless performed in the previous 6 months.

b. At least once per 18 months by demonstrating the OPERABILITY of overvoltage, undervoltage, and underfrequency protective instrumentation by performance of a CHANNEL CALIBRATION including simulated automatic actuation of the protective relays, tripping logic and output circuit breakers and verifying the following setpoints.

   1. Overvoltage $\leq$ 132 VAC,

   2. Undervoltage $\geq$ 108 VAC,

   3. Underfrequency $\geq$ 57 Hz.

SURVEILLANCE REQUIREMENTS (Continued)

b. Performance of a CHANNEL FUNCTIONAL TEST:

1. Within 24 hours prior to the start of CORE ALTERATIONS, and

2. At least once per 7 days.

c. Verifying that the channel count rate is at least 0.7 cps[#]:

1. Prior to control rod withdrawal,

2. Prior to and at least once per 12 hours during CORE ALTERATIONS, and

3. At least once per 24 hours.

d. Verifying that the RPS circuitry "shorting links" have been removed within 8 hours prior to and at least once per 12 hours during:

1. The time any control rod is withdrawn,[##] or

2. Shutdown margin demonstrations.

[#]Provided signal-to-noise ratio is ≥ 2. Otherwise, 3 cps.

[##]Not required for control rods removed per Specification 3.9.10.1 or 3.9.10.2.

3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

HIGH WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.11.1 At least one shutdown cooling mode loop of the residual heat removal (RHR) system shall be OPERABLE# and in operation* with at least:

a. One OPERABLE RHR pump, and

b. One OPERABLE RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITION 5, when irradiated fuel is in the reactor vessel and the water level is greater than or equal to 22 feet above the top of the reactor pressure vessel flange.

ACTION:

a. With no RHR shutdown cooling mode loop OPERABLE, within 1 hour and at least once per 24 hours thereafter, demonstrate the operability of at least one alternate method capable of decay heat removal. Otherwise, suspend all operations involving an increase in the reactor decay heat load and establish SECONDARY CONTAINMENT INTEGRITY within 4 hours.

b. With no RHR shutdown cooling mode loop in operation, within 1 hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature at least once per hour.

SURVEILLANCE REQUIREMENTS

4.9.11.1 At least one shutdown cooling mode loop of the residual heat removal system or alternate method shall be verified to be in operation and circulating reactor coolant at least once per 12 hours.

*The shutdown cooling pump be removed from operation for up to 2 hours per 8-hour period.

#The normal or emergency power source may be inoperable.

LOW WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.11.2 Two shutdown cooling mode loops of the residual heat removal (RHR) system shall be OPERABLE# and at least one loop shall be in operation,* with each loop consisting of at least:

a. One OPERABLE RHR pump, and

b. One OPERABLE RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITION 5, when irradiated fuel is in the reactor vessel and the water level is less than 22 feet above the top of the reactor pressure vessel flange.

ACTION:

a. With less than the above required shutdown cooling mode loops of the RHR system OPERABLE, within one hour and at least once per 24 hours thereafter, demonstrate the operability of at least one alternate method capable of decay heat removal for each inoperable RHR shutdown cooling mode loop.

b. With no RHR shutdown cooling mode loop in operation, within 1 hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature at least once per hour.

SURVEILLANCE REQUIREMENTS

4.9.11.2 At least one shutdown cooling mode loop of the residual heat removal system or alternate method shall be verified to be in operation and circulating reactor coolant at least once per 12 hours.

*The shutdown cooling pump may be removed from operation for up to 2 hours per 8-hour period.

#The normal or emergency power source may be inoperable for each loop.

TABLE 4.11.1-1

RADIOACTIVE LIQUID WASTE SAMPLING AND ANALYSIS PROGRAM

Liquid Release Type	Sampling Frequency	Minimum Analysis Frequency	Type of Activity Analysis	Lower Limit of Detection (LLD) (μCi/ml)[a]
A. Batch Waste Release Tanks[d]	P Each Batch	P Each Batch	Principal Gamma Emitters[f]	5x10-7
			I-131	$1x10^{-6}$
	P One Batch/M	M	Dissolved and Entrained Gases (Gamma emitters)	$1x10^{-5}$
	P Each Batch	M Composite[b]	H-3	$1x10^{-5}$
			Gross Alpha	$1x10^{-7}$
	P Each Batch	Q Composite[b]	Sr-89, Sr-90	$5x10^{-8}$
			Fe-55	$1x10^{-6}$
B. Continuous Releases[e]	Continuous[c]	W Composite[c]	Principal Gamma Emitters[f]	$5x10^{-7}$
			I-131	$1x10^{-5}$
	M Grab Sample	M	Dissolved and Entrained Gases (Gamma Emitters)	$1x10^{-5}$
	Continuous[c]	M Composite[c]	H-3	$1x10^{-5}$
			Gross Alpha	$1x10^{-7}$
	Continuous[c]	Q Composite[c]	Sr-89, Sr-90	$5x10^{-8}$
			Fe-55	$1x10^{-6}$

3/4.11.2 GASEOUS EFFLUENTS

DOSE RATE

LIMITING CONDITION FOR OPERATION

3.11.2.1 The dose rate due to radioactive materials released in gaseous effluents from the site (see Figure 5.1.1-1) shall be limited to the following:

a. For noble gases: Less than or equal to 500 mrem/yr to the total body and less than or equal to 3000 mrem/yr to the skin, and

b. For all radioiodines and for all radioactive materials in particulate form and radionuclides (other than noble gases) with half lives greater than 8 days: Less than or equal to 1500 mrems/yr to any organ via the inhalation pathway.

APPLICABILITY: At all times.

ACTION:

With the dose rate(s) exceeding the above limits, immediately decrease the release rate to within the above limit(s).

SURVEILLANCE REQUIREMENTS

4.11.2.1.1 The dose rate due to noble gases in gaseous effluents shall be determined to be within the above limits in accordance with the methods and procedures of the ODCM.

4.11.2.1.2 The dose rate due to radioactive materials, other than noble gases, in gaseous effluents shall be determined to be within the above limits in accordance with the methods and procedures of the ODCM by obtaining representative samples and performing analyses in accordance with sampling and analysis program specified in Table 4.11.2-1.

TABLE 4.11.2-1 (Continued)

TABLE NOTATION

b. Analyses shall also be performed following shutdown, startup, or a THERMAL POWER change exceeding 15% of the RATED THERMAL POWER within a 1 hour period.

c. Whenever there is flow through the SBGTS.

d. Samples shall be changed at least once per 7 days and analyses shall be completed within 48 hours after changing or after removal from sampler. Sampling shall also be performed at least once per 24 hours for at least 7 days following each shutdown, startup or THERMAL POWER change exceeding 15 percent of RATED THERMAL POWER in 1 hour and analyses completed within 48 hours of changing. When samples collected for 24 hours are analyzed, the corresponding LLD's may be increased by a factor of 10.

This requirement does not apply if (1) analysis shows that the DOSE EQUIVALENT I-131 concentration in the primary coolant has not increased more than a factor of 3; (2) the noble gas monitor shows that effluent activity has not increased more than a factor of 3.

e. Tritium grab samples shall be taken at least once per 7 days from the plant vent to determine tritium releases in the ventilation exhaust from the spent fuel pool area whenever spent fuel is in the spent fuel pool.

f. The ratio of the sample flow rate to the sampled stream flow rate shall be known for the time period covered by each dose or dose rate calculation made in accordance with Specifications 3.11.2.1, 3.11.2.2 and 3.11.2.3.

g. The principal gamma emitters for which the LLD specification applies include the following radionuclides: Kr-87, Kr-88, Xe-133, Xe-133m, Xe-135, and Xe-138 for gaseous emissions and Mn-54, Fe-59, Co-58, Co-60, Zn-65, Mo-99, Cs-134, Cs-137, Ce-141 and Ce-144 for particulate emissions. This list does not mean that only these nuclides are to be detected and reported. Other peaks which are measurable and identifiable, at the 95% confidence level, together with the above nuclides, shall also be identified and reported.

DOSE - NOBLE GASES

LIMITING CONDITION FOR OPERATION

3.11.2.2 The air dose due to noble gases released in gaseous effluents, from each reactor unit, from the site (see Figure 5.1.1-1) shall be limited to the following:

a. During any calendar quarter: Less than or equal to 5 mrad for gamma radiation and less than or equal to 10 mrad for beta radiation, and

b. During any calendar year: Less than or equal to 10 mrad for gamma radiation and less than or equal to 20 mrad for beta radiation.

APPLICABILITY: At all times.

ACTION:

a. With the calculated air dose from radioactive noble gases in gaseous effluents exceeding any of the above limits, in lieu of any other report required by Specification 6.6.A or 6.6.B, prepare and submit to the Commission within 30 days, pursuant to Specification 6.6.C, a Special Report which identifies the cause(s) for exceeding the limit(s) and defines the corrective actions to be taken to reduce the releases and the proposed corrective actions to be taken to assure that subsequent releases will be in compliance with the above limits.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.2.2 Dose Calculations Cumulative dose contributions for the current calendar quarter and current calendar year shall be determined in accordance with the ODCM at least once per 31 days.

DOSE - RADIOIODINES, RADIOACTIVE MATERIALS IN PARTICULATE FORM, AND RADIONUCLIDES OTHER THAN NOBLE GASES

LIMITING CONDITION FOR OPERATION

3.11.2.3 The dose to an individual from radioiodines and radioactive materials in particulate form, and radionuclides, other than noble gases, with half-lives greater than 8 days in gaseous effluents released, from each reactor unit, from the site (see Figure 5.1.1-1) shall be limited to the following:

a. During any calendar quarter: Less than or equal to 7.5 mrems to any organ, and

b. During any calendar year: Less than or equal to 15 mrems to any organ.

APPLICABILITY: At all times.

ACTION:

a. With the calculated dose from the release of radioiodines, radioactive materials in particulate form, or radionuclides (other than noble gases) with half lives greater than 8 days, in gaseous effluents exceeding any of the above limits, in lieu of any other report required by Specification 6.6.A or 6.6.B, prepare and submit to the Commission within 30 days, pursuant to Specification 6.6.C, a Special Report which identifies the cause(s) for exceeding the limit and defines the corrective actions that have been taken to reduce the releases and the proposed corrective actions to be taken to assure that subsequent releases will be in compliance with the above limits.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.2.3 Dose Calculations Cumulative dose contributions for the current calendar quarter and current calendar year shall be determined in accordance with the ODCM at least once per 31 days.

VENTING OR PURGING

LIMITING CONDITION FOR OPERATION

3.11.2.8 VENTING or PURGING of the containment drywell shall be through the Primary Containment Vent and Purge System or the Standby Gas Treatment System.

APPLICABILITY: Whenever the drywell is vented or purged.

ACTION:

a. With the requirements of the above specification not satisfied, suspend all VENTING and PURGING of the drywell.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.2.8.1 The containment drywell shall be determined to be aligned for VENTING or PURGING through the Primary Containment Vent and Purge System or the Standby Gas Treatment System within 4 hours prior to start of and at least once per 12 hours during VENTING or PURGING of the drywell.

4.11.8.2 Prior to use of the Purge System through the Standby Gas Treatment System in OPERATIONAL CONDITION 1, 2 or 3 assure that:

a. Both Standby Gas Treatment System trains are OPERABLE, and

b. Only one of the Standby Gas Treatment System trains is used for PURGING.

3/4.12 RADIOLOGICAL ENVIRONMENTAL MONITORING

3/4.12.1 MONITORING PROGRAM

LIMITING CONDITION FOR OPERATION

3.12.1 The radiological environmental monitoring program shall be conducted as specified in Table 3.12.1-1.

APPLICABILITY: At all times.

ACTION:

a. With the radiological environmental monitoring program not being conducted as specified in Table 3.12.1-1, in lieu of any other report required by Specification 6.6.A or 6.6.B, prepare and submit to the Commission, in the Annual Radiological Operating Report, a description of the reasons for not conducting the program as required and the plans for preventing a recurrence.

b. With the level of radioactivity in an environmental sampling medium exceeding the reporting levels in Table 3.12.1-2 when averaged over any calendar quarter, in lieu of any other report required by Specification 6.6.A or 6.6.B, prepare and submit to the Commission within 30 days from the end of the affected calendar quarter a Report pursuant to Specification 6.9.1.13. When more than one of the radionuclides in Table 3.12.1-2 are detected in the sampling medium, this report shall be submitted if:

$$\frac{\text{concentration (1)}}{\text{limit level (1)}} + \frac{\text{concentration (2)}}{\text{limit level (2)}} + \ldots \geq 1.0$$

When radionuclides other than those in Table 3.12.1-2 are detected and are the result of plant effluents, this report shall be submitted if the potential annual dose to an individual is equal to or greater than the calendar year limits of Specifications 3.11.1.2, 3.11.2.2 and 3.11.2.3. This report is not required if the measured level of radioactivity was not the result of plant effluents; however, in such an event, the condition shall be reported and described in the Annual Radiological Environmental Operating Report.

c. With milk or fresh leafy vegetable samples unavailable from one or more of the sample locations required by Table 3.12.1-1, in lieu of any other report required by Specification 6.6.A or 6.6.B, prepare and submit to the Commission within 30 days, pursuant to Specification 6.6.C, a Special Report which identifies the cause of the unavailability of samples and identifies locations for obtaining replacement samples. The locations from which samples were unavailable may then be deleted from those required by Table 3.12.1-1, provided the locations from which the replacement samples were obtained are added to the environmental monitoring program as replacement locations.

d. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

TABLE 3.12.1-1 (Continued)

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

Exposure Pathway and/or Sample	Minimum Number of Samples and Sample Locations*	Sampling and Collection Frequency	Type and Frequency of Analysis
3. WATERBORNE			
a. Surface	2 locations	Composite sample collected over a period of ≤ 31 days.	Gamma isotopic analysis of each composite sample. Tritium analysis of composite sample at least once per 92 days.
b. Ground	5 locations	At least once per 92 days.	Gamma isotopic and tritium analyses of each sample.
c. Sediment from Shoreline	1 location	At least once per 184 days.	Gamma isotopic analysis of each sample.

The specifications of this section provide the general requirements applicable to each of the Limiting Conditions for Operation and Surveillance Requirements within Section 3/4. In the event of a disagreement between the requirements stated in these Technical Specifications and those stated in an applicable Regulation or Act, the requirements stated in the applicable Regulation or Act, shall take precedence and shall be met.

3.0.1 This specification states the applicability of each specification in terms of defined OPERATIONAL CONDITION or other specified applicability condition and is provided to delineate specifically when each specification is applicable.

3.0.2 This specification defines those conditions necessary to constitute compliance with the terms of an individual Limiting Condition for Operation and associated ACTION requirement.

3.0.3 This specification delineates the measures to be taken for circumstances not directly provided for in the ACTION statements and whose occurrence would violate the intent of the specification. For example, Specification 3.7.2 requires two control room and auxiliary electric equipment room emergency filtration trains to be OPERABLE and provides explicit ACTION requirements if one train is inoperable. Under the requirements of Specification 3.0.3, if both of the required trains are inoperable, within 1 hour measures must be initiated to place the unit in at least STARTUP within the next 6 hours, in at least HOT SHUTDOWN within the following 6 hours and in COLD SHUTDOWN within the subsequent 24 hours. As a further example, Specification 3.6.6.1 requires two primary containment hydrogen recombiner systems to be OPERABLE and provides explicit ACTION requirements if one recombiner system is inoperable. Under the requirements of Specification 3.0.3, if both of the required systems are inoperable, within 1 hour measures must be initiated to place the unit in at least STARTUP within the next 6 hours and in at least HOT SHUTDOWN within the following 6 hours. It is acceptable to initiate and complete a reduction in OPERATIONAL CONDITIONS in a shorter time interval than required in the ACTION statement and to add the unused portion of this allowable out-of-service time to that provided for operation in subsequent lower OPERATIONAL CONDITION(S). Stated allowable out-of-service times are applicable regardless of the OPERATIONAL CONDITION(S) in which the inoperability is discovered but the times provided for achieving a CONDITION reduction are not applicable if the inoperability is discovered in a CONDITION lower than the applicable CONDITION.

3.0.4 This specification provides that entry into an OPERATIONAL CONDITION must be made with (a) the full complement of required systems, equipment or components OPERABLE and (b) all other parameters as specified in the Limiting Conditions for Operation being met without regard for allowable deviations and out of service provisions contained in the ACTION statements.

The intent of this provision is to ensure that unit operation is not initiated with either required equipment or systems inoperable or other limits being exceeded.

Exceptions to this provision have been provided for a limited number of specifications when startup with inoperable equipment would not affect plant safety. These exceptions are stated in the ACTION statements of the appropriate specifications.

3/4.1. 1 SHUTDOWN MARGIN

A sufficient SHUTDOWN MARGIN ensures that (1) the reactor can be made subcritical from all operating conditions, (2) the reactivity transients associated with postulated accident conditions are controllable within acceptable limits, and (3) the reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

Since core reactivity values will vary through core life as a function of fuel depletion and poison burnup, the demonstration of SHUTDOWN MARGIN will be performed in the cold, xenon-free condition and shall show the core to be subcritical by at least R + 0.38% delta K or R + 0.28% delta K, as appropriate. The value of R in units of % delta K is the difference between the calculated value of maximum core reactivity during the operating cycle and the calculated beginning-of-life core reactivity. The value of R must be positive or zero and must be determined for each fuel loading cycle.

Two different values are supplied in the Limiting Condition for Operation to provide for the different methods of demonstration of the SHUTDOWN MARGIN. The highest worth rod may be determined analytically or by test. The SHUTDOWN MARGIN is demonstrated by an insequence control rod withdrawal at the beginning-of-life fuel cycle conditions, and, if necessary, at any future time in the cycle if the first demonstration indicates that the required margin could be reduced as a function of exposure. Observation of subcriticality in this condition assures subcriticality with the most reactive control rod fully withdrawn.

This reactivity characteristic has been a basic assumption in the analysis of plant performance and can be best demonstrated at the time of fuel loading, but the margin must also be determined anytime a control rod is incapable of insertion.

3/4.1.2 REACTIVITY ANOMALIES

Since the SHUTDOWN MARGIN requirement for the reactor is small, a careful check on actual conditions to the predicted conditions is necessary, and the changes in reactivity can be inferred from these comparisons of rod patterns. Since the comparisons are easily done, frequent checks are not an imposition on normal operations. A 1% change is larger than is expected for normal operation so a change of this magnitude should be thoroughly evaluated. A change as large as 1% would not exceed the design conditions of the reactor and is on the safe side of the postulated transients.

3/4.1.3 CONTROL RODS

The specification of this section ensure that (1) the minimum SHUTDOWN MARGIN is maintained, (2) the control rod insertion times are consistent with those used in the accident analysis, and (3) the potential effects of the rod drop accident are limited. The ACTION statements permit variations from the basic requirements but at the same time impose more restrictive criteria for continued operation. A limitation on inoperable rods is set such that the resultant effect on total rod worth and scram shape will be kept to a minimum. The requirements for the various scram time measurements ensure that any indication of systematic problems with rod drives will be investigated on a timely basis.

Damage within the control rod drive mechanism could be a generic problem, therefore with a control rod immovable because of excessive friction or mechanical interference, operation of the reactor is limited to a time period which is reasonable to determine the cause of the inoperability and at the same time prevent operation with a large number of inoperable control rods.

Control rods that are inoperable for other reasons are permitted to be taken out of service provided that those in the nonfully-inserted position are consistent with the SHUTDOWN MARGIN requirements.

The number of control rods permitted to be inoperable could be more than the eight allowed by the specification, but the occurrence of eight inoperable rods could be indicative of a generic problem and the reactor must be shutdown for investigation and resolution of the problem.

The control rod system is designed to bring the reactor subcritical at a rate fast enough to prevent the MCPR from becoming less than the fuel cladding safety limit during the limiting power transient analyzed in Section 15.0 of the FSAR. This analysis shows that the negative reactivity rates resulting from the scram with the average response of all the drives as given in the specifications, provide the required protection and MCPR remains greater than the fuel cladding safety limit. The occurrence of scram times longer then those specified should be viewed as an indication of a systemic problem with the rod drives and therefore the surveillance interval is reduced in order to prevent operation of the reactor for long periods of time with a potentially serious problem.

The scram discharge volume is required to be OPERABLE so that it will be available when needed to accept discharge water from the control rods during a reactor scram and will isolate the reactor coolant system from the environment when required.

Control rods with inoperable accumulators are declared inoperable and Specification 3.1.3.1 then applies. This prevents a pattern of inoperable accumulators that would result in less reactivity insertion on a scram than has been analyzed even though control rods with inoperable accumulators may still be inserted with normal drive water pressure. Operability of the accumulator ensures that there is a means available to insert the control rods even under the most unfavorable depressurization of the reactors.

3/4.1.6 ECONOMIC GENERATION CONTROL SYSTEM

Operation with the economic generation control (EGC) system, automatic flow control, is limited to the range of 65% to 100% of rated core flow. In this flow range and with THERMAL POWER $\geq$ 20% of RATED THERMAL POWER, the reactor could safely tolerate a rate of change of load of 8 MWe/s (reference FSAR Section 6.2.4).

Limits within the EGC and the flow control system prevent rates of change greater than approximately 4 MWe/s. When EGC is in operation, this fact will be indicated on the main control room console.

3/4.2 POWER DISTRIBUTION LIMITS

BASES

The specifications of this section assure that the peak cladding temperature following the postulated design basis loss-of-coolant accident will not exceed the 2200°F limit specified in 10 CFR 50.46.

3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

This specification assures that the peak cladding temperature following the postulated design basis loss-of-coolant accident will not exceed the limit specified in 10 CFR 50.46.

The peak cladding temperature (PCT) following a postulated loss-of-coolant accident is primarily a function of the average heat generation rate of all the rods of a fuel assembly at any axial location and is dependent only secondarily on the rod to rod power distribution within an assembly. The peak clad temperature is calculated assuming a LHGR for the highest powered rod which is equal to or less than the design LHGR corrected for densification. This LHGR times 1.02 is used in the heatup code along with the exposure dependent steady state gap conductance and rod-to-rod local peaking factor. The Technical Specification AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) is this LHGR of the highest powered rod divided by its local peaking factor. The limiting value for APLHGR is shown in Figure 3.2.1-1, for two loop operation. These values shall be multiplied by a factor of 0.85 for single recirculation loop operation. This multiplier is determined from comparison of the limiting analysis between two recirculation loop and single recirculation loop operation.

The calculational procedure used to establish the APLHGR shown on Figure 3.2.1-1 is based on a loss-of-coolant accident analysis. The analysis was performed using General Electric (GE) calculational models which are consistent with the requirements of Appendix K to 10 CFR 50. A complete discussion of each code employed in the analysis is presented in Reference 1. Differences in this analysis compared to previous analyses performed with Reference 1 are: (1) the analysis assumes a fuel assembly planar power consistent with 102% of the MAPLHGR shown in Figure 3.2.1-1, (2) fission product decay is computed assuming an energy release rate of 200 MEV/fission; (3) pool boiling is assumed after nucleate boiling is lost during the flow stagnation period; and (4) the effects of core spray entrainment and countercurrent flow limitation as described in Reference 2, are included in the reflooding calculations.

A list of the significant plant input parameters to the loss-of-coolant accident analysis is presented in Bases Table B 3.2.1-1.

3/4.2.2 APRM SETPOINTS

The fuel cladding integrity Safety Limits of Specification 2.1 were based on a power distribution which would yield the design LHGR at RATED THERMAL POWER. The flow biased simulated thermal power-upscale scram setting and control rod block functions of the APRM instruments for both two recirculation loop operation and single recirculation loop operation must be adjusted to ensure that the MCPR does not become less than the fuel cladding safety limit or that $\geq$ 1% plastic strain does not occur in the degraded situation. The scram settings and rod block settings are adjusted in accordance with the formula in this specification when the combination of THERMAL POWER and MFLPD indicates a higher peaked power distribution to ensure that an LHGR transient would not be increased in the degraded condition.

3/4.2.3 MINIMUM CRITICAL POWER RATIO

The required operating limit MCPRs at steady state operating conditions as specified in Specification 3.2.3 are derived from the established fuel cladding integrity Safety Limit MCPR, and an analysis of abnormal operational transients. For any abnormal operating transient analysis evaluation with the initial condition of the reactor being at the steady-state operating limit, it is required that the resulting MCPR does not decrease below the Safety Limit MCPR at any time during the transient assuming instrument trip setting given in Specification 2.2.

To assure that the fuel cladding integrity Safety Limit is not exceeded during any anticipated abnormal operational transient, the most limiting transients have been analyzed to determine which result in the largest reduction in CRITICAL POWER RATIO (CPR). The type of transients evaluated were loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease. The limiting transient yields the largest delta MCPR. When added to the Safety Limit MCPR, the required minimum operating limit MCPR of Specification 3.2.3 is obtained and presented in Figure 3.2.3-1.

The evaluation of a given transient begins with the system initial parameters shown in FSAR Table 15.0-1 that are input to a GE-core dynamic behavior transient computer program. The code used to evaluate pressurization events is described in NEDO-24154[3] and the program used in nonpressurization events is described in NEDO-10802[2]. The outputs of this program along with the initial MCPR form the input for further analyses of the thermally limiting bundle with the single channel transient thermal hydraulic TASC code described in NEDE-25149[4] The principal result of this evaluation is the reduction in MCPR caused by the transient.

The need to adjust the MCPR operating limit as a function of scram time arises from the statistical approach used in the implementation of the ODYN computer code for analyzing rapid pressurization events. Generic statistical analyses were performed for plant groupings of similar design which considered the statistical variation in several parameters, i.e., initial power level, CRD scram insertion time, and model uncertainty. These analyses, which are

FIRE DETECTION INSTRUMENTATION (Continued)

In the event that a portion of the fire detection instrumentation is inoperable, increasing the frequency of fire watch patrols in the affected areas in required to provide detection capability until the inoperable instrumentation is restored to OPERABILITY.

3/3.3.7.10 RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

The radioactive liquid effluent monitoring instrumentation is provided to monitor and control, as applicable, the releases of radioactive materials in liquid effluents during actual or potential releases of liquid effluents. The alarm/trip setpoints for these instruments shall be calculated in accordance with the procedures in the ODCM to ensure that the alarm/trip will occur prior to exceeding the limits of 10 CFR Part 20. The OPERABILITY and use of this instrumentation is consistent with the requirements of General Design Criteria 60, 63 and 64 of Appendix A to 10 CFR Part 50.

3/4.3.7.11 RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

The radioactive gaseous effluent monitoring instrumentation is provided to monitor and control, as applicable, the releases of radioactive materials in gaseous effluents during actual or potential releases of gaseous effluents. The alarm/trip setpoints for these insruments shall be calculated in accordance with the procedures in the ODCM to ensure that the alarm/trip will occur prior to exceeding the limits of 10 CFR Part 20. This instrumentation also includes provisions for monitoring (and controlling) the concentrations of potentially explosive gas mixtures in the waste gas holdup system. The OPERABILITY and use of this instrumentation is consistent with the requirements of General Design Criteria 60, 63 and 64 of Appendix A to 10 CFR Part 50.

3/4.3.7.12 LOOSE-PART DETECTION SYSTEM

The OPERABILITY of the loose-part detection system ensures that sufficient capability is available to detect loose metallic parts in the primary system and avoid or mitigate damage to primary system components. The allowable out-of-service times and surveillance requirements are consistent with the recommendations of Regulatory Guide 1.133, "Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors."

3/4.3.8 FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

The feedwater/main turbine trip system actuation instrumentation is provided to initiate the feedwater system/main turbine trip system in the event of reactor vessel water level equal to or greater than the level 8 setpoint associated with a feedwater controller failure, to prevent overfilling the reactor vessel which may result in high pressure liquid discharge through the safety/relief valve discharge lines.

3/4.4.1 RECIRCULATION SYSTEM

Operation with one reactor core coolant recirculation loop inoperable has been evaluated and been found to be acceptable during the first fuel cycle only, provided the unit is operated in accordance with the single recirculation loop operation Technical Specifications herein.

An inoperable jet pump is not, in itself, a sufficient reason to declare a recirculation loop inoperable, but it does present a hazard in case of a design-basis-accident by increasing the blowdown area and reducing the capability of reflooding the core; thus, the requirement for shutdown of the facility with a jet pump inoperable. Jet pump failure can be detected by monitoring jet pump performance on a prescribed scheduled for significant degradation.

Recirculation loop flow mismatch limits are in compliance with the ECCS LOCA analysis design criterion. The limits will ensure an adequate core flow coastdown from either recirculation loop following a LOCA. Where the recirculation loop flow mismatch limits can not be maintained during the recirculation loop operation, continued operation is permitted in the single recirculation loop operation mode.

In order to prevent undue stress on the vessel nozzles and bottom head region, the recirculation loop temperatures shall be within 50°F of each other prior to startup of an idle loop. The loop temperature must also be within 50°F of the reactor pressure vessel coolant temperature to prevent thermal shock to the recirculation pump and recirculation nozzles. Since the coolant in the bottom of the vessel is at a lower temperature than the water in the upper regions of the core, undue stress on the vessel would result if the temperature difference was greater than 145°F.

3/4.4.2 SAFETY/RELIEF VALVES

The safety valve function of the safety-relief valves operate to prevent the reactor coolant system from being pressurized above the Safety Limit of 1325 psig in accordance with the ASME Code. A total of 18 OPERABLE safety/relief valves is required to limit reactor pressure to within ASME III allowable values for the worst case upset transient.

Demonstration of the safety-relief valve lift settings will occur only during shutdown and will be performed in accordance with the provisions of Specification 4.0.5.

3/4.5.1 and 3/4.5.2 ECCS - OPERATING and SHUTDOWN

ECCS Division 1 consists of the low pressure core spray system, low pressure coolant injection subsystem "A" of the RHR system, and the automatic depressurization system (ADS) as actuated by ADS trip system "A". ECCS Division 2 consists of low pressure coolant injection subsystems "B"and "C" of the RHR system and the automatic depressurization system as actuated by ADS trip system "B".

The low pressure core spray (LPCS) system is provided to assure that the core is adequately cooled following a loss-of-coolant accident and provides adequate core cooling capacity for all break sizes up to and including the double-ended reactor recirculation line break, and for smaller breaks following depressurization by the ADS.

The LPCS is a primary source of emergency core cooling after the reactor vessel is depressurized and a source for flooding of the core in case of accidental draining.

The surveillance requirements provide adequate assurance that the LPCS system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage to piping and to start cooling at the earliest moment.

The low pressure coolant injection (LPCI) mode of the RHR system is provided to assure that the core is adequately cooled following a loss-of-coolant accident. Three subsystems, each with one pump, provide adequate core flooding for all break sizes up to and including the double-ended reactor recirculation line break, and for small breaks following depressurization by the ADS.

The surveillance requirements provide adequate assurance that the LPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage to piping and to start cooling at the earliest moment.

ECCS Division 3 consists of the high pressure core spray system. The high pressure core spray (HPCS) system is provided to assure that the reactor core is adequately cooled to limit fuel clad temperature in the event of a small break in the reactor coolant system and loss of coolant which does not result in rapid depressurization of the reactor vessel. The HPCS system permits the reactor to be shut down while maintaining sufficient reactor vessel water level inventory until the vessel is depressurized. The HPCS system operates over a range of 1160 psid, differential pressure between reactor vessel and HPCS suction source, to 0 psid.

The capacity of the HPCS system is selected to provide the required core cooling. The HPCS pump is designed to deliver greater than or equal to 516/1550/6200 gpm at differential pressures of 1160/1130/200 psid. Initially, water from the condensate storage tank is used instead of injecting water from

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 facility. Structural integrity is required to ensure that the containment will withstand the maximum pressure of 45 psig in the event of a LOCA. The measurement of containment tendon lift-off force, the tensile tests of the tendon wires or strands, the visual examination of tendons, anchorages and exposed interior and exterior surfaces of the containment, the chemical and visual examination of the sheathing filler grease, and the Type A leakage test are sufficient to demonstrate this capability.

The surveillance requirements for demonstrating the primary containment's structural integrity and the method of predicting the pre-stress loses are in compliance with the recommendations of Regulatory Guide 1.35.1, "Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containment Structures," January 1976, and proposed Regulatory Guide 1.35.1, "Determining Prestressing Forces for Inspection of Prestressed Concrete Containment Structures," April 1979 with the following clarification: the tested lift-off force of individual tendon tension shall be greater than or equal to the initial pre-stress minus the loses, as predicted in the as-built design, which occur between the initial pre-operational structural integrity test and the time of subsequent surveillance.

The required Special Reports from any engineering evaluation or containment abnormalities shall include a description of the tendon condition, the condition of the concrete (especially at tendon anchorages), the inspection procedure, the tolerances on cracking, the results of the engineering evaluation, and the corrective action taken.

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 39.6 psig does not exceed the design pressure of 45 psig during LOCA conditions or that the external pressure differential does not exceed the design maximum external pressure differential of 5 psid. The limit of 2.0 psig for initial positive primary containment pressure will limit the total pressure to 39.6 psig which is less than the design pressure and is consistent with the accident 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 LOCA conditions and is consistent with the accident 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, de-inerting and pressure control. Until these valves have been demonstrated capable of closing during a LOCA or steam line break accident, they shall be blocked so as not to open more than 50°.

3/4.7.6 FIRE RATED ASSEMBLIES

The OPERABILITY of the fire barriers and barrier penetrations ensure that fire damage will be limited. These design features minimize the possibility of a single fire involving more than one fire area prior to detection and extinguishment. The fire barriers, fire barrier penetrations for conduits, cable trays and piping, fire windows, fire dampers, and fire doors are periodically inspected to verify their OPERABILITY.

3/4.7.7 AREA TEMPERATURE MONITORING

The area temperature limitations ensure that safety-related equipment will not be subjected to temperatures in excess of their environmental qualification temperatures. Exposure to excessive temperatures may degrade equipment and can cause loss of its OPERABILITY. The temperature limits include allowance for an instrument error of ± 7°F.

3/4.7.8 STRUCTURAL INTEGRITY OF CLASS 1 STRUCTURES

In order to assure that settlement does not exceed predicted and allowable settlement values, a program has been established to conduct a survey at the site. The allowable total differential settlement values are based on original settlement predictions. In establishing these tabulated values, an assumption is made that pipe and conduit connection have been designed to safely withstand the stresses which would develop due to total and differential settlement.

3/4 7.9 SNUBBERS

All snubbers are required OPERABLE to ensure that the structural integrity of the Reactor Coolant System and all other safety-related systems is maintained during and following a seismic or other event initiating dynamic loads. Snubbers excluded from this inspection program are those installed on nonsafety-related systems and then only if their failure or failure of the system on which they are installed, would have no adverse effect on any safety-related system.

Snubbers are classified and grouped by design and manufacturer but not by size. For example, mechanical snubbers utilizing the same design features of the 2-kip, 10-kip, and 100-kip capacity manufactured by Company "A" are of the same type. The same design mechanical snubbers manufactured by Company "B" for the purpose of this Technical Specification would be of a different type, as would hydraulic snubbers from either manufacturer.

A list of individual snubbers with detailed information of snubbers location and size and of system affected shall be available at the plant in accordance with Section 50.71(c) of 10 CFR Part 50. The accessibility of each

SNUBBERS (Continued)

snubber shall be determined and approved by the Onsite Review and Investigative Function. The determination shall be based upon the existing radiation levels and the expected time to perform a visual inspection in each snubber location as well as other factors associated with accessibility during plant operations (e.g., temperature, atmosphere, location, etc.), and the recommendations of Regulatory Guide 8.8 and 8.10. The addition or deletion of any hydraulic or mechanical snubber shall be made in accordance with Section 50.59 of 10 CFR Part 50.

The visual inspection frequency is based upon maintaining a constant level of snubber protection to each safety-related system. Therefore, the required inspection interval varies inversely with the observed snubber failures on a given system and is determined by the number of inoperable snubbers found during an inspection of each system. In order to establish the inspection frequency for each type of snubber on a safety-related system, it was assumed that the frequency of snubber failures and initiating events is constant with time and that the failure of any snubber on that system could cause the system to be unprotected and to result in failure during an assumed initiating event. Inspections performed before that interval has elapsed may be used as a new reference point to determine the next inspection. However, the results of such early inspections performed before the original required time interval has elapsed (nominal time less 25%) may not be used to lengthen the required inspection interval. Any inspection whose results require a shorter inspection interval will override the previous schedule.

The acceptance criteria are to be used in the visual inspection to determine OPERABILITY of the snubbers. For example, if a fluid port of a hydraulic snubber is found to be uncovered, the snubber shall be declared inoperable and shall not be determined OPERABLE via functional testing.

To provide assurance of snubber functional reliability, one of three functional testing methods is used with stated acceptance criteria:

1. Functionally test 10% of a type of snubber with an additional 10% tested for each functional testing failure, or

2. Functionally test a sample size and determine sample acceptance or rejection using Figure 4.7-1, or

3. Functionally test a sample size and determine sample acceptance or rejection using the stated equation.

SNUBBERS (Continued)

Figure 4.7-1 was developed using "Wald's Sequential Probability Ratio Plan" as described in "Quality Control and Industrial Statistics" by Acheson J. Duncan.

Permanent or other exemptions from the surveillance program for individual snubbers may be granted by the Commission if a justifiable basis for exemption is presented and, if applicable, snubber life destructive testing was performed to qualify the snubber for the applicable design conditions at either the completion of their fabrication or at a subsequent date. Snubbers so exempted shall be listed in the list of individual snubbers indicating the extent of the exemptions.

The service life of a snubber is evaluated via manufacturer input and information through consideration of the snubber service conditions and associated installation and maintenance records (newly installed snubbers, seal replaced, spring replaced, in high radiation area, in high temperature area, etc.). The requirement to monitor the snubber service life is included to ensure that the snubbers periodically undergo a performance evaluation in view of their age and operating conditions. These records will provide statistical bases for future consideration of snubber service life.

3/4.7.10 MAIN TURBINE BYPASS SYSTEM

The main turbine bypass system is required OPERABLE as assumed in the feedwater controller failure analysis.

3/4.11 RADIOACTIVE EFFLUENTS

BASES

3/4.11.1 LIQUID EFFLUENTS

3/4.11.1.1 CONCENTRATION

This specification is provided to ensure that the concentration of radioactive materials released in liquid waste effluents from the site will be less than the concentration levels specified in 10 CFR Part 20, Appendix B, Table II, Column 2. This limitation provides additional assurance that the levels of radioactive materials in bodies of water outside the site will result in exposure within (1) the Section II.A design objectives of Appendix I, 10 CFR 50, to an individual, and (2) the limits of 10 CFR 20.106(e) to the population. The concentration limits for dissolved or entrained noble gases were determined by converting their MPC's in air to an equivalent concentration in water using the methods described in International Commission on Radiological Protection (ICRP) Publication 2.

3/4.11.1.2 DOSE

This specification is provided to implement the requirements of Sections II.A, III.A and IV.A of Appendix I, 10 CFR Part 50. The Limiting Condition for Operation implements to guides set forth in Section II.A of Appendix I. The ACTION statements provide the required operating flexibility and at the same time implement the guides set forth in Section IV.A of Appendix I to assure that the releases of radioactive material in liquid effluents will be kept "as low as is reasonably achievable." Also, for fresh water sites with drinking water supplies which can be potentially affected by plant operations, there is reasonable assurance that the operation of the facility will not result in radionuclide concentrations in the finished drinking water that are in excess of the requirements of 40 CFR 141. The dose calculations in the ODCM implement the requirements in Section III.A of Appendix I that conformance with the guides of Appendix I be shown by calculational procedures based on models and data, such that the actual exposure of an individual through appropriate pathways is unlikely to be substantially underestimated. The equations specified in the ODCM for calculating the doses due to the actual release rates of radioactive materials in liquid effluents are consistent with the methodology provided in Regulatory Guide 1.109, "Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I," Revision 1, October 1977 and Regulatory Guide 1.113, "Estimating Aquatic Dispersion of Effluents from Accidental and Routine Reactor Releases for the Purpose of Implementing Appendix I," April 1977.

This specification applies to the release of radioactive materials in liquid effluents from each reactor at the site. For units with shared radwaste treatment systems, the liquid effluents from the shared system are proportioned among the units sharing that system.

DOSE RATE (Continued)

infant via the cow-milk-infant pathway to less than or equal to 1500 mrem/ year for the nearest cow to the plant.

This specification applies to the release of radioactive effluents in gaseous effluents from all reactors at the site. For units within shared radwaste treatment systems, the gaseous effluents from the shared system are proportioned among the units sharing that system.

3/4.11.2.2 DOSE - NOBLE GASES

This specification is provided to implement the requirements of Sections II.B, III.A and IV.A of Appendix I, 10 CFR Part 50. The Limiting Conditions for Operation are the guides set forth in Section II.B of Appendix I. The ACTION statements provide the required operating flexibility and at the same time implement the guides set forth in Section IV.A of Appendix I to assure that the releases of radioactive material in gaseous effluents will be kept "as low as is reasonably achievable." The Surveillance Requirements implement the requirements in Section III.A of Appendix I that conformance with the guides of Appendix I be shown by calculational procedures based on models and data such that the actual exposure of an individual through appropriate pathways is unlikely to be substantially underestimated. The dose calculations established in the ODCM for calculating the doses due to the actual release rates of radioactive noble gases in gaseous effluents are consistent with the methodology provided in Regulatory Guide 1.109, "Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I," Revision 1, October 1977 and Regulatory Guide 1.111, "Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water Cooled Reactors," Revision 1, July 1977. The ODCM equations provided for determining the air doses at the site boundary are based upon the historical average atmospheric conditions.

3/4.11.2.3 DOSE - RADIOIODINES, RADIOACTIVE MATERIALS IN PARTICULATE FORM AND RADIONUCLIDES OTHER THAN NOBLE GASES

The specification is provided to implement the requirements of Sections II.C, III.A and IV.A of Appendix I, 10 CFR Part 50. The Limiting Conditions for Operation are the guides set forth in Section II.C of Appendix I. The ACTION statements provide the required operating flexibility and at the same time implement the guides set forth in Section IV.A of Appendix I to assure that the releases of radioactive materials in gaseous effluents will be kept "as low as is reasonably achievable." The ODCM calculational methods specified in the Surveillance Requirements implement the requirements in Section III.A of

3/4.12.1 MONITORING PROGRAM

The radiological monitoring program required by this specification provides measurements of radiation and of radioactive materials in those exposure pathways and for those radionuclides which lead to the highest potential radiation exposures of individuals resulting from the station operation. This monitoring program thereby supplements the radiological effluent monitoring program by verifying that the measurable concentrations of radioactive materials and levels of radiation are not higher than expected on the basis of the effluent measurements and modeling of the environmental exposure pathways. The initially specified monitoring program will be effective for at least the first 3 years of commercial operation, as defined in the ODCM.

The detection capabilities required by Table 4.12-1 are state-of-the-art for routine environmental measurements in industrial laboratories. It should be recognized that the LLD is defined as an "a priori" (before the fact) limit representing the capability of a measurement system and not as "a posteriori" (after the fact) limit for a particular measurement. Analyses shall be performed in such a manner that the stated LLDs will be achieved under routine conditions. Occasionally background fluctuations, unavoidably small sample sizes, the presence of interfering nuclides, or other uncontrollable circumstances may render these LLDs unachievable. In such cases, the contributing factors will be identified and described in the Annual Radiological Environmental Operating Report.

3/4.12.2 LAND USE CENSUS

This specification is provided to ensure that changes in the use of unrestricted areas are identified and that modifications to the monitoring program are made if required by the results of this census. The best survey information from the door-to-door survey, aerial survey or consulting with local agricultural authorities shall be used. This census satisfies the requirements of Section IV.B.3 of Appendix I to 10 CFR Part 50.

5.0 DESIGN FEATURES

5.1 SITE

EXCLUSION AREA

5.1.1 The exclusion area shall be as shown in Figure 5.1.1-1.

LOW POPULATION ZONE

5.1.2 The low population zone shall be as shown in Figure 5.1.2-1.

SITE BOUNDARY FOR GASEOUS EFFLUENTS

5.1.3 The site boundary for gaseous effluents shall be as shown in Figure 5.1.1-1.

SITE BOUNDARY FOR LIQUID EFFLUENTS

5.1.4 The site boundary for liquid effluents shall be as shown in Figure 5.1.1-1.

5.2 CONTAINMENT

CONFIGURATION

5.2.1 The primary containment is a steel lined post-tensioned concrete structure consisting of a drywell and suppression chamber. The drywell is a steel-lined post-stressed concrete vessel in the shape of a truncated cone closed by a steel dome. The drywell is above a cylindrical steel-lined post-stressed concrete suppression chamber and is attached to the suppression chamber through a series of downcomer vents. The drywell has a minimum free air volume of 229,538 cubic feet. The suppression chamber has an air region of 164,800 to 168,100 cubic feet and a water region of 128,800 to 131,900 cubic feet.

DESIGN TEMPERATURE AND PRESSURE

5.2.2 The primary containment is designed and shall be maintained for:

a. Maximum internal pressure 45 psig.

b. Maximum internal temperature: drywell 340°F.
suppression chamber 275°F.

c. Maximum external pressure 5 psig.

d. Maximum floor differential pressure: 25 psid, downward.
5 psid, upward.

SECONDARY CONTAINMENT

5.2.3 The secondary containment consists of the Reactor Building, the equipment access structure and a portion of the main steam tunnel and has a minimum free volume of 2,875,000 cubic feet.

Any deviation from the above guidelines shall be authorized by the (Station Superintendent or his deputy, or higher levels of management, in accordance with established procedures and with documentation of the basis for granting the deviation. Controls shall be included in the procedures such that individual overtime shall be reviewed monthly by the Station Superintendent or his designee to assure that excessive hours have not been assigned. Routine deviation from the above guidelines is not authorized.

D. Qualifications of the station management and operating staff shall meet minimum acceptable levels as described in ANSI N18.1, "Selection and Training of Nuclear Power Plant Personnel," dated March 8, 1971. The Rad/Chem Supervisor shall meet the requirements of radiation protection manager of Regulatory Guide 1.8, September, 1975. The ANSI N18.1-1971 qualification requirements for Rad/Chem Technician may also be met by either of the following alternatives:

1. Individuals who have completed the Rad/Chem Technician training program and have accrued 1 year of working experience in the specialty, or

2. Individuals who have completed the Rad/Chem Technician training program, but have not yet accrued 1 year of working experience in the specialty, who are supervised by on-shift health physics supervision who meet the requirements of ANSI N18.1-1971 Section 4.3.2, "Supervisor Not Requiring AEC Licenses," or Section 4.4.4, "Radiation Protection."

E. Retraining and replacement training of Station personnel shall be in accordance with ANSI N18.1, "Selection and Training of Nuclear Power Plant Personnel", dated March 8, 1971 and Appendix "A" of 10 CFR Part 55, and shall include familiarization with relevant industry operational experience identified by the ONSG.

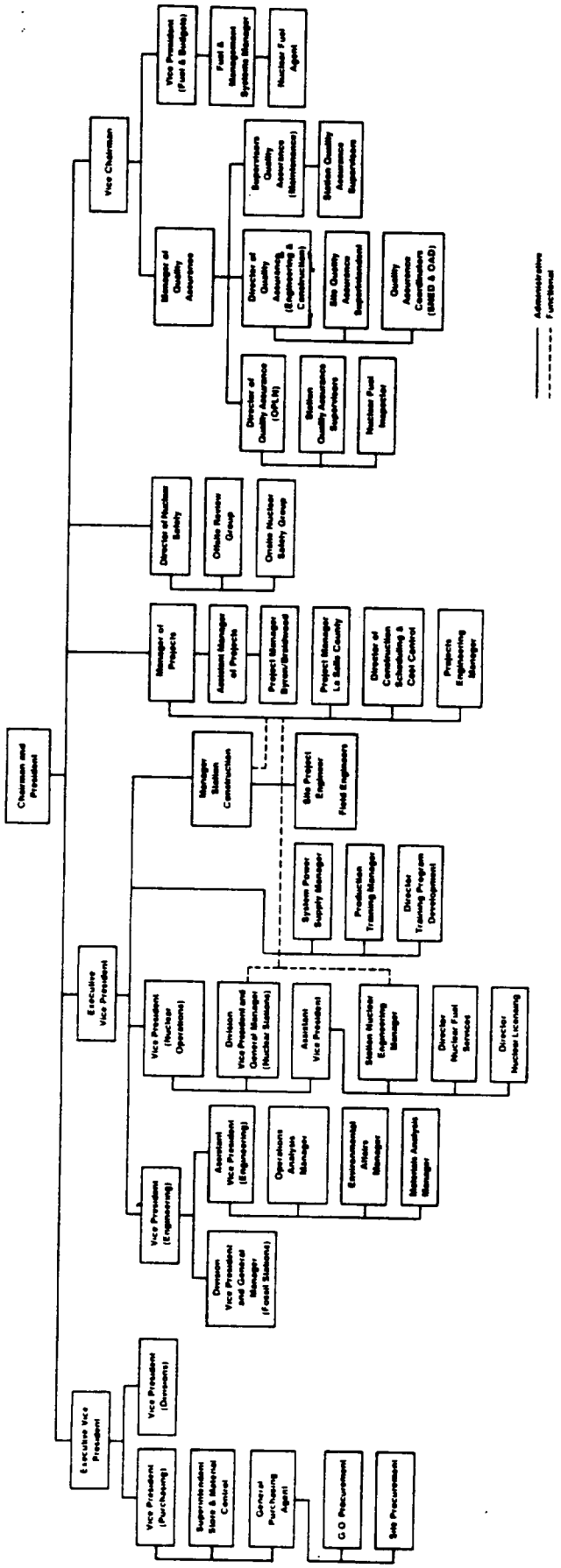
F. Retraining shall be conducted at intervals not exceeding 2 years.

G. The Review and Investigative Function and the Audit Function of activities affecting quality during facility operations shall be constituted and have the responsibilities and authorities outlined below:

1. The Supervisor of the Offsite Review and Investigative Function shall be appointed by the Director, Nuclear Safety. The Audit Function shall be the responsibility of the Manager of Quality Assurance and shall be independent of operations.

   a. Offsite Review and Investigative Function

      The Supervisor of the Offsite Review and Investigative Function shall: (1) provide directions for the review and investigative function and appoint a senior participant to provide appropriate direction, (2) select each participant for this function, (3) select a complement of more than one participant who collectively possess background and qualifications in the subject matter under review to provide comprehensive interdisciplinary review coverage



CORPORATE MANAGEMENT

Figure 6.1-1

Figure 6.1-3

MINIMUM SHIFT CREW COMPOSITION

WITH UNIT 1 IN CONDITION 1, 2, OR 3		
POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION	
	CONDITIONS 1, 2 and 3	CONDITIONS 4 and 5
SE	1[a]	1[a]
SF	1[a]	None
RO	2[b]	1
AO	2[b]	1
SCRE	1[a]	None

or, whenever a SCRE (SRO/STA) is not included in the shift crew composition, the minimum shift crew composition shall be as follows:

WITH UNIT 1 IN CONDITION 1, 2, OR 3		
POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION	
	CONDITIONS 1, 2 and 3	CONDITIONS 4 and 5
SE	1[a]	1[a]
SF	1[a]	None
RO	2[b]	1
AO	2[b]	1
STA	1[a]	None

WITH UNIT 1 IN CONDITION 4 OR 5 OR DEFUELED		
POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION	
	CONDITIONS 1, 2 and 3	CONDITIONS 4 and 5
SE	1[a]	1[a]
SF	1	None
RO	2	1
AO	2	2[b]
STA	1	None

Figure 6.1-3 (Continued)

MINIMUM SHIFT CREW COMPOSITION

NOTES

a/ Individual may fill the same position on Unit 2.
b/ One of the two required individuals may fill the same position on Unit 2.
SE - Shift Supervisor (Shift Engineer) with a Senior Reactor Operators License on Unit 1.
SF - Shift Foreman with a Senior Reactor Operators License on Unit 1.
RO - Individual with a Reactor Operators License on Unit 1.
AO - Auxiliary Operator.
SCRE - Station Control Room Engineer with a Senior Reactor Operators License.

Except for the Shift Supervisor, the Shift Crew Composition may be one less than the minimum requirements of Figure 6.1-3 for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements of Figure 6.1-3. This provision does not permit any shift crew position to be unmanned upon shift change due to an oncoming shift crewman being late or absent.

While the unit is in OPERATIONAL CONDITION 1, 2, or 3, an individual with a valid SRO license shall be designated to assume the Control Room direction function. While the unit is in OPERATIONAL CONDITION 4 or 5, an individual with a valid SRO or RO license shall be designated to assume the Control Room direction function.

PLANT OPERATING RECORDS (Continued)

B. Records and/or logs relative to the following items shall be recorded in a manner convenient for review and shall be retained for the life of the plant:

1. Substitution or replacement of principal items of equipment pertaining to nuclear safety;

2. Changes made to the plant as it is described in the SAR;

3. Records of new and spent fuel inventory and assembly histories;

4. Updated, corrected, and as-built drawings of the plant;

5. Records of plant radiation and contamination surveys;

6. Records of offsite environmental monitoring surveys;

7. Records of radiation exposure for all plant personnel, including all contractors and visitors to the plant, in accordance with 10 CFR Part 20;

8. Records of of radioactivity in liquid and gaseous wastes released to the environment;

9. Records of transient or operational cycling for those components that have been designed to operate safety for a limited number of transient or operational cycles (identified in Table 5.7.1-1);

10. Records of individual staff members indicating qualifications, experience, training, and retraining;

11. Inservice inspections of the reactor coolant system;

12. Minutes of meetings and results of reviews and audits performed by the offsite and onsite review and audit functions;

13. Records of reactor tests and experiments;

14. Records of Quality Assurance activities required by the QA Manual;

15. Records of reviews performed for changes made to procedures on equipment or reviews of tests and experiments pursuant to 10 CFR 50.59; and

16. Records of the service lives of all hydraulic and mechanical snubbers required by specification 3.7.9 including the date at which the service life commences and associated installation and maintenance records.

17. Records of analyses required by the radiological environmental monitoring program.

Thirty-Day Written Reports (Continued)

e. An unplanned offsite release of 1) more than 1 curie of radioactive material in liquid effluents, 2) more than 150 curies of noble gas in gaseous effluents, or 3) more than 0.05 curies of radioiodine in gaseous effluents. The report of an unplanned offsite release of radioactive material shall include the following information:

1. A description of the event and equipment involved.
2. Cause(s) for the unplanned release.
3. Actions taken to prevent recurrence.
4. Consequences of the unplanned release.

f. Measured levels of radioactivity in an environmental sampling medium determined to exceed the reporting level values of Table 3.12-2 when averaged over any calendar quarter sampling period.

C. Unique Reporting Requirements

1. Special Reports shall be submitted to the Director of the Office of Inspection and Enforcement (Region III) within the time period specified for each report.

6.7 PROCESS CONTROL PROGRAM (PCP)*

6.7.1 The PCP shall be approved by the Commission prior to implementation.

6.7.2 Licensee initiated changes to the PCP:

a. Shall be submitted to the Commission in the semi annual Radioactive Effluent Release Report for the period in which the change(s) was made. This submittal shall contain:

1. Sufficiently detailed information to totally support the rationale for the change without benefit of additional or supplemental information;
2. A determination that the change did not reduce the overall conformance of the solidified waste product to existing criteria for solid wastes; and
3. Documentation of the fact that the change has been reviewed and found acceptable by the Onsite Review and Investigative Function.

b. Shall become effective upon review and acceptance by the Onsite Review and Investigative Function.

(PCP)* Common to LaSalle Unit 1 and LaSalle Unit 2

6.8 OFFSITE DOSE CALCULATION MANUAL (ODCM)*

6.8.1 The ODCM shall be approved by the Commission prior to implementation.

6.8.2 Licensee initiated changes to the ODCM:

a. Shall be submitted to the Commission within 90 days of the date the change(s) was made effective. This submittal shall contain:

1. Sufficiently detailed information to totally support the rationale for the change without benefit of additional or supplemental information. Information submitted should consist of a package of those pages of the ODCM to be changed with each page numbered and provided with an approval and date box, together with appropriate analyses or evaluations justifying the change(s);

2. A determination that the change will not reduce the accuracy or reliability of dose calculations or setpoint determinations; and

3. Documentation of the fact that the change has been reviewed and found acceptable by the Onsite Review and Investigative Function.

b. Shall become effective upon review and acceptance by the Onsite Review and Investigative Function.

6.9 MAJOR CHANGES TO RADIOACTIVE WASTE TREATEMENT SYSTEMS

6.9.1 Licensee initiated major changes to the radioactive waste systems (liquid, gaseous and solid):

a. Shall be reported to the Commission in the Monthly Operating Report for the period in which the evaluation was reviewed by the Onsite Review and Investigative Function. The discussion of each change shall contain:

1. A summary of the evaluation that led to the determination that the change could be made in accordance with 10 CFR 50.59;

2. Sufficient detailed information to totally support the reason for the change without benefit or additional or supplemental information;

3. A detailed description of the equipment, components and processes involved and the interfaces with other plant systems;

*(ODCM) Common to LaSalle Unit 1 and LaSalle Unit 2

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

SAFETY EVALUATION

AMENDMENT NO. 18 TO NPF-11

LA SALLE COUNTY STATION, UNIT 1

DOCKET NO. 50-373

Introduction

By letter dated January 13,1984, and as modified by letters of March 11, 1984, and April 5, 1984, Commonwealth Edison Company (the licensee) proposed an amendment that would revise the La Salle Unit 1 Technical Specifications to reflect changes incorporated into the La Salle Unit 2 Technical Specifications. The licensee committed to update the Unit 1 Technical Specifications to those issued for Unit 2 where the changes did not involve specific design differences. These changes are required for consistency and uniformity between Unit 1 and Unit 2 Technical Specifications; will minimize the potential for confusion and Technical Specification violation; and allow a consistent basis for operating, maintenance and surveillance procedures for both units.

The following is a list of the changes to the Unit 1 Technical Specifications based on the Unit 2 Technical Specifications:

1. Page XIX through XXIII - add list of Tables and Figures.
2. Page 1-9, ***footnote would be modified to state "moved" instead of "coupled" so as to allow control rod testing required by the Technical Specifications in addition to coupling.
3. Single recirculation loop operation previously approved for Unit 1 would be moved into the body of the Tech Specs, pages 2-1, 2-4, 3/4 2-1, 3/4 2-3, 3/4 2-4, 3/4 3-53, 3/4 4-1, 3/4 4-1a, 3/4 4-2, and 3/4 4-3.
4. Page 3/4 1-1 - Tech Spec 4.1.1.c would be revised to allow 12 hours instead of 1 hour for the performance of specified surveillance.

5. Page 3/4 1-3 - add word "withdrawn" to action statement b.1.a)1) to clarify that, if an inoperable control rod is not "withdrawn" its safety function is met and need not be considered in determining separation from withdrawn operable control rods.
6. Page 3/4 1-5 - add footnote to allow reactor startup to perform test if necessary.
7. Pages 3/4 1-6, 3/4 1-8, 3/4 1-9 and, 3/4 1-14 - control rods specifications 3.1.3.2., 3.1.3.4, 3.1.3.5., and 3.1.3.7 would add "3.0.4 not applicable" thus permitting reactor startup with various control rod parameters not met as long as Tech. Spec action statements are followed.
8. Pages 3/4 3-4, 3/4 3-5, 3/4 3-41 - would delete startup test setpoint verification footnote since the startup tests are completed.
9. Pages 3/4 3-11, 3/4 3-14 - add footnote (i) to allow bypass of MSIV delta T leak detection trip channels for up to 4 hours.
10. Pages 3/4 3-15 - revise reactor water cleanup ambient and differential temperature setpoints.
11. Pages 3/4 3-15, 3/4 3-16, 3/4 3-17 - would delete startup test setpoint verification footnote since the startup tests are completed.
12. Pages 3/4 3-18, 3/4 3-19 - add greater than or equal to 5 second time delay reference based on the requirements in license condition 2.C.(30).(b) that time delay relays be used.

13. Pages 3/4 3-39, 3/4 2-4, 3/4 2-5 - add change to allow operation if EOC-RPT inoperable in accordance with the provisions of the Standard Technical Specificantions for GE Boiling Water Reactors.
14. Page 3/4 3-54 - revise APRM calibration frequency to semi-annually in accordance with the provisions of the Standard Technical Specifications for GE Boiling Water Reactors.
15. Pages 3/4 3-60, 3/4 3-63 - add footnote to clarify that the seismic and meteorological monitoring systems are common systems shared by Units 1 and 2.
16. Pages 3/4 3-72 and 3/4 9-4 - add footnote to require a signal-to-noise ratio greater than 2 for source range count rates between 0.7 counts per second and 3 counts per second.
17. Pages 3/4 3-81, 3/4 11-13, 3/4 11-14 - revise radioactive effluent reporting requirements.
18. Page 3/4 3-90 - would specify that isolation of the off gas system is required only during channel calibration.
19. Page 3/4 4-2 - modify the surveillance and operability requirements for the jet pumps to reflect the fact that there is no requirment for immediate scram upon loss of both recirculation pumps.
20. Page 3/4 4-5 - revise tolerance on safety relief valve settings from +1% to + or - 1%.
21. Page 3/4 4-7 - revise tolerance on reactor coolant system (RCS) pressure at which leak rate limits for RCS isolation valves are applied from + or - 10 psig to + or - 50 psig.

22. Page 3/4 4-19 - revise withdrawal times for reactor vessel material specimens to conform to regulations.

23. Pages 3/4 5-3, 3/4 5-4, 3/4 5-5 - water tight doors specifications for ECCS corner rooms would be added.

24. Page 3/4 5-5 - revised High Pressure Core Spray delta P setpoint.

25. Page 3/4 5-9 - delete footnote for startup test setpoint verification since startup tests are completed.

26. Pages 3/4 6-2, 3/4 6-3 - revise calculation method of Main Steam Isolation Valve leakage rate limit in accordance with the Standard Technical Specification for GE Boiling Water Reactors.

27. Pages 3/4 6-B, 3/4 6-9 - revise action statements and surveillance requirements and make table clarifications for containment tendons.

28. Pages 3/4 6-15 and 3/4 11-19 - add limitation on using standby gas treatment system for purging the primary containment.

29. Pages 3/4 3-70, 3/4 6-16, 3/4 6-17, 3/4 6-18 - delete Safety Relief Valve test footnote since tests have been completed.

30. Table 3.6.3-1. (Pages 3/4 6-24, 3/4 6-25, 3/4 6-26, 3/4 6-27, 3/4 6-28, 3/4 6-32, 3/4 6-34)

    a. (Primary Containment Isolation System valves) add # (3.0.4 not applicable) to various valves to reflect that the valves, when closed, maintain containment integrity and need not be operable.

    b. Revise butterfly valve closure times after first refueling outage. (Also some VQ valve closure times would be changed immediately.)

c. Valves ICM023B & 2CM024A would be deleted from the list of containment isolation valves since these are, in fact, not containment valves.

d. Valve 1E12-F099B would be added to the list of required containment isolation valves to correct an inadvertant omission.

31. Page 3/4 7-8 - delete footnote allowing crosstie of 250 volt batteries as it is inconsistent with other requirements in the Tech. Specs.

32. Page 3/4 7-12 - revise fire pump parameters and fire suppression water system pressure.

33. Page 3/4 7-25 - (Table 3.7.7-1) revise the temperature range limits for various areas of Unit 1 to conform to the provisions of the Standard Technical Specifications for GE Boiling Water Reactors and to comply with requirements for certain equipment operability.

34. Pages 3/4 7-27 through 3/4 7-45 - the entire technical specification for inspection, testing and monitoring of safety-related snubbers would be revised.

35. Page 3/4 7-46:

a. Delete calibration requirement for Main Turbine Bypass System and delete valve positioning requirement to conform to the Standard Tech. Spec. for GE Boiling Water Reactor.

b. Correct the definition of the conditions under which the Main Turbine Bypass System must be operable to conform to the standard Tech. Spec. for GE Boiling Water Reactor.

c. Delete startup test footnote since the startup tests have been completed.

36. Diesels:

a. Page 3/4 8-2 - add explanation to diesel generator 2A inoperable action f. to prevent excessive testing of diesel generator 1A when system inoperable.

b. Page 3/4 8-4 - delete surveillance item 6 which currently requires a verification of diesel generator loading in accord with design requirements.

c. Page 3/4 8-6 - delete the requirement for diesel generator surveillance starts on stored air.

37. Page 3/4 8-8 - change 'and/or' to 'or' to clarify that only 1 of the Division 1 or Division 2 diesel generators need be available during reactor shutdown.

38. Page 3/4 8-10 - revise equipment needed for Unit 2 Division 1 AC electrical system.

39. Page 3/4 8-12 - change 'and/or' to 'or' to clarify that only 1 of the Division 1 or Division 2 diesel generators need be available during reactor shutdown.

40. Pages 3/4 8-14, 3/4 8-15, 3/4 8-17 - delete Unit 2 Division 1 DC sources and delete ability to crosstie as it is inconsistent with other requirements in the Tech. Specs.

41. Page 3/4 8-19 - change 'and/or'to 'or' to clarify that Division 3 and only 1 of Division 1 or Division 2 DC sources need be available during reactor shutdown.

42. Page 3/4 8-21 - add drywell hoists and cranes to drywell circuits to be deenergized and delete them from page 3/4 8-24.

43. Page 3/4 8-26 - add "3.0.4 not applicable" to thermal overload bypass specification to indicate that reactor startup need not be restricted when administrative controls in accordance with the action statement are taken for an inoperable thermal overload bypass circuit.

44. Page 3/4 8-27 - delete valve 1VQ041 from thermal overload table since the valve was inadvertantly included in the table.

45. Page 3/4 8-31 - revise requirements to functionally test the Reactor Protection System Electric Power Assemblies only during cold shutdowns greater than 24 hours.

46. Page 3/4 11-3 - delete P-32 from the list of isotopes for which liquid waste sampling is required in Table 4.11.1-1.

47. Page 3/4 11-12 - revise sampling requirement when Dose Equivalent I-131 concentration in primary coolant and noble gas monitors activity meets certain limits.

48. Page 3/4 12-3 - revise number of sample locations (Table 3.12.1-1) to reflect actual installed sample locations defined in the Offsite Dose Calculation Manual.

49. Page 5-1 - correct drywell free volume in design features portion of the Tech. Spec.

50. Page 6-11 - revise corporate management Figure 6.1-1 to reflect current approved management configuration.

51. Pages 6-13, 6-14 - new shift manning Table for two units.

52. Pages 6-28, 6-29 - add footnote to clarify that the Process Control Program and the Offsite Dose Calculation Manual are common to both Unit 1 and Unit 2.

53. Pages with minor changes of a nonsubstantive nature (e.g. adding comma, parenthesis wording change for clarification, etc.):

    a. Page II, VIII, XV.

    b. Pages 3/4 1-4, 3/4 1-11, 3/4 1-19.

    c. Pages 3/4 3-1, 3/4 3-58, 3/4 3-82, 3/4 3-83, 3/4 3-84.

    d. Pages 3/4 4-13, 3/4 4-14, 3/4 4-17, 3/4 4-23, 3/4 4-24.

    e. Pages 3/4 5-8

    f. Pages 3/4 6-5, 3/4 6-11, 3/4 6-19, 3/4 6-20, 3/4 6-21, 3/4 6-33, 3/4 6-35, 3/4 6-36, 3/4 6-37, 3/4 6-38, 3/4 6-40, 3/4 6-41.

    g. Pages 3/4 7-14, 3/4 7-17, 3/4 7-18, 3/4 7-22, 3/4 7-24.

    h. Pages 3/4 8-1, 3/4 8-5, 3/4 8-7, 3/4 8-9, 3/4 8-16.

    i. Pages 3/4 9-16, 3/4 9-17.

    j. Page 3/4 11-9.

    k. Pages 3/4 12-1, 3/4 12-4.

    l. Pages 6-3, 6-20

Evaluation

The bulk of the changes to the Technical Specifications are administrative in nature and are necessary:

(1) To correct typing errors, correction of publication, updating the index (Table of Contents), minor changes to add clarity, updating to reflect two unit operation, updating to current corporate organizational chart which was found acceptable when the Unit 2 license was issued, deleting footnote which apply to an already satisfactory completed startup test setpoint verification, and deletion and addition for inadvertent error: (items are enumerated as above) Items 1, 5, 8, 11, 15, 17, 20, 21, 25, 29, 30 c&d, 31, 35c, 37, 39, 40, 41, 44, 48, 49, 50, 52 and 53 a, b, c, d, e, f, g, h, i, j, k, l.

(2) To incorporate into the Technical Specifications the substance of the previously authorized Amendment 11 to the license for single loop operation and to be consistent with the Unit 2 Technical Specification to incorporate these requirements into the Unit 1 Technical Specification similarly as in Unit 2: Items 3 and 19

(3) To delete duplication of Technical Specifications requirement for sampling to measure possible iodine spiking: Item 47

(4) To incorporate the option allowed by Generic Letter 84-13 dated May 3, 1984, to totally eliminate the table snubber listing which does not alter snubber surveillance or operability requirement but only allows removal of snubber listing in the Technical Specification: Item 34

As stated, all of the above changes are administrative in nature. The remaining changes to the Technical Specification, though, fall into two categories: (1) Requirements more conservative than the present Unit 1 requirements (Item 10, 12, 16, 22, 23, 24, 26, 28, 30b, 32, 33, 42, and 45; or (2) Changes that may result in some increase to the probability of accident or may result in some way in a decrease of a safety margin, but the results of the changes are within acceptable criteria (Items 2, 4, 6, 7, 9, 13, 14, 18, 27, 30a&b, 35 a&b, 36, 38, 43, 46, and 51.

These changes to the Technical Specifications as indicated above were submitted by the licensee to the NRC staff to make both units' Technical Specifications consistent. The NRC staff reviewed these changes and finds that the requested amendment to the La Salle Unit 1 license, to be consistent with La Salle Unit 2, does not result in a reduction of safety and is acceptable.

In view of the foregoing, the NRC concludes that these changes to the La Salle Unit 1 Technical Specifications are appropriate and should be incorporated into the La Salle Unit 1 Technical Specifications.

Environmental Consideration

This amendment involves a change in the installation or use of a facility component located within the restricted area. 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 occupation 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 51.2(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of this amendment.

Conclusion

We have 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 security or to the health and safety of the public.

Dated: August 8, 1984