JUNE 1 1 1980

Docket Nos. 50-325
and 50-324

Mr. J. A. Jones
Senior Executive Vice President
Carolina Power & Light Company
336 Fayetteville Street
Raleigh, North Carolina 27602

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R Dewens

Dear Mr. Jones:

The Commission has issued the enclosed Amendment No. 28 to Facility Operating License No. DPR-71 and Amendment No. 51 to Facility Operating License No. DPR-62 for the Brunswick Steam Electric Plant (BSEP), Unit Nos. 1 and 2, respectively. These amendments consist of changes to the Technical Specifications in response to your applications dated October 25, December 27, 1976; July 28, 1977; January 18, February 2, March 6, March 21, April 13, April 27, May 1, May 29, October 8, November 7, December 31, 1979; February 5, February 20, April 1, April 11, April 22, May 21, and May 27, 1980.

The amendment for BSEP Unit No. 2 changes the Technical Specifications to establish revised safety and operating limits for operation in fuel Cycle No. 4, and revises the table of safety related hydraulic snubbers.

The amendments for BSEP Unit Nos. 1 and 2 change the Technical Specifications to (1) conform to the installed Degraded Grid Voltage Protection system, (2) provide for the End-of-Cycle Recirculation Pump Trip feature, (3) allow lowering the reactor vessel water level for extended maintenance during refueling outages, (4) reflect revisions on the corporate organizational structure, (5) change the operability test requirements for the RHR Service Water Pumps, and (6) clarify the reporting requirements in the Appendix B Environmental Technical Specifications. In addition, the language of the Reactor Protection System Instrumentation Specification was revised in accordance with our letter dated Februatry 12, 1979. Other miscellaneous editorial changes were made to bring the BSEP Technical Specifications into conformance with the current GE STS.

Included with this amendment is Supplement No. 2 to the Fire Protection Safety Evaluation and related technical specifications which complete the staff's fire protection review for BSEP, Units 1 and 2.

6D

OFFICE						
SURNAME						
DATE						

JUNE 11 1980

Copies of the Safety Evaluation and the Notice of Issuance are also enclosed.

Sincerely,

Thomas A. Ippolito, Chief
Operating Reactors Branch #2
Division of Licensing

Enclosures:
1. Amendment No. 28 to DPR-71
2. Amendment No. 51 to DPR-62
3. Safety Evaluation
4. Supplement #2 to the Fire Protection SE for Brunswick Steam Electric Plant Units 1 and 2
5. Notice

cc w/enclosures:
See next page

F.R. Notice + Amendment only

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SURNAME	SNorris:kk	JHannon	TNovak	KARMAN	TIppolito	
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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

June 11, 1980

Docket Nos. 50-325
and 50-324

Mr. J. A. Jones
Senior Executive Vice President
Carolina Power & Light Company
336 Fayetteville Street
Raleigh, North Carolina 27602

Dear Mr. Jones:

The Commission has issued the enclosed Amendment No. 28 to Facility Operating License No. DPR-71 and Amendment No. 51 to Facility Operating License No. DPR-62 for the Brunswick Steam Electric Plant (BSEP), Unit Nos. 1 and 2, respectively. These amendments consist of changes to the Technical Specifications in response to your applications dated October 25, December 27, 1976; July 28, 1977; January 18, February 2, March 6, March 21, April 13, April 27, May 1, May 29, October 8, November 7, December 31, 1979; February 5, February 20, April 1, April 11, April 22, May 21, and May 27, 1980.

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Included with this amendment is Supplement No. 2 to the Fire Protection Safety Evaluation and related technical specifications which complete the staff's fire protection review for BSEP, Units 1 and 2.

Copies of the Safety Evaluation and the Notice of Issuance are also enclosed.

Sincerely,

for RBBevan
Thomas A. Ippolito, Chief
Operating Reactors Branch #2
Division of Licensing

Enclosures:
1. Amendment No. 28 to DPR-71
2. Amendment No. 51 to DPR-62
3. Safety Evaluation
4. Supplement #2 to the Fire Protection SE for Brunswick Steam Electric Plant Units 1 and 2
5. Notice

cc w/enclosures:
See next page

cc:

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109 W. Moore Street
Southport, North Carolina 28461

Director, Technical Assessment Division
Office of Radiation Programs (AW-459)
US EPA
Crystal Mall #2
Arlington, Virginia 20460

U. S. Environmental Protection Agency
Region IV Office
ATTN: EIS COORDINATOR
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Atlanta, Georgia 30308

Resident Inspector
U. S. Nuclear Regulatory Commission
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Southport, North Carolina 28461

Mr. Fred Tollison
Plant Manager
P. O. Box 458
Southport, North Carolina 28461

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

CAROLINA POWER & LIGHT COMPANY

DOCKET NO. 50-325

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NO. 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 28
License No. DPR-71

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

   A. The applications for amendment by Carolina Power & Light Company dated October 25, December 27, 1976; July 28, 1977; January 18, February 2, March 6, March 21, April 13, April 27, May 1, May 29, October 8, November 7, December 31, 1979; February 5, February 20, April 1, April 11, April 22, May 21, and May 27, 1980 comply with the standards and requirements of the Atomic Energy Act of of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

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

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

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

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

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment and paragraqph 2.C.(2) of Facility Operating License No. DPR-71 is hereby amended to read as follows:

   (2) Technical Specifications

   The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 28 are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

8006270 037

3. This license amendment is effective as of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

for RB Bevan
Thomas A. Ippolito, Chief
Operating Reactors Branch #2
Division of Licensing

Attachment:
Changes to the Technical
Specifications

Date of Issuance: June 11, 1980

ATTACHMENT TO LICENSE AMENDMENT NO. 28

FACILITY OPERATING LICENSE NO. DPR-71

DOCKET NO. 50-325

Remove	Insert
VII/VIII	VII/VIII
IX/X	IX/X
XI/XII	XI/XII
XIII/XIV	XIII/XIV
XV	XV
3/4 0-1/2	3/4 0-1/2
3/4 3-1/2	3/4 3-1/2
3/4 3-3/4	3/4 3-3/4
3/4 3-5/6	3/4 3-5/6
3/4 3-9/10	3/4 3-9/10
3/4 3-15/16	3/4 3-15/16
3/4 3-29/30	3/4 3-29/30
3/4 3-31/32	3/4 3-31/32
3/4 3-33/34	3/4 3-33/34
3/4 3-35/36	3/4 3-35/35a
-----------	3/4 3-36
-----------	3/4 3-38a
3/4 7-1/2.	3/4 7-1/2
3/4 7-45/46	3/4 7-45/46
3/4 10-5,6,7	----------
B3/4 0-1/2	B3/4 0-1/2
B3/4 7-3/4	B3/4 7-3/4
B3/4 10-1	B3/4 10-1
6-1/2	6-1/2
6-3/4	6-3/4
6-5/6	6-5/6
6-7/8	6-7/8
6-9/10	6-9/10
6-11/12	6-11/12
6-13/14	6-13/14
6-15/16	6-15/16
6-19/20	6-19/20
Appendix B	
5-1	5-1
5-2	5-2
5-3	5-3
Figure 5.1-1	Figure 5.1-1
5-6	5-6
5-7	5-7

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

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3/4.4 REACTOR COOLANT SYSTEM (Continued)

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DESIGN FEATURES

ADMINISTRATIVE CONTROLS

ADMINISTRATIVE CONTROLS

3/4.0 APPLICABILITY

LIMITING CONDITION FOR OPERATION

3.0.1 Limiting Conditions for Operation and ACTION requirements shall be applicable during the OPERATIONAL CONDITIONS or other states specified for each specification.

3.0.2 Adherence to the requirements of the Limiting Condition for Operation and associated ACTION within the specified time interval shall constitute compliance with the specification. In the event the Limiting Condition for Operation is restored prior to expiration of the specified time interval, completion of the ACTION statement is not required.

3.0.3 In the event a Limiting Condition for Operation and/or associated ACTION requirements cannot be satisfied because of circumstances in excess of those addressed in the specification, the facility shall be placed in at least HOT SHUTDOWN within 6 hours and in COLD SHUTDOWN within the following 30 hours unless corrective measures are completed that permit operation under the permissible ACTION statements for the specified time interval as measured from initial discovery or until the reactor is placed in an OPERATIONAL CONDITION in which the specification is not applicable. Exceptions to these requirements shall be stated in the individual specifications.

3.0.4 Entry into an OPERATIONAL CONDITION or other specified applicability state shall not be made unless the conditions of the Limiting Condition for Operation are met without reliance on provisions contained in the ACTION statements unless otherwise excepted. This provision shall not prevent passage thru OPERATIONAL CONDITIONS required to comply with ACTION requirements.

SURVEILLANCE REQUIREMENTS

4.0.1 Surveillance Requirements shall be applicable during the OPERATIONAL CONDITIONS or other states specified for individual Limiting Conditions for Operation unless otherwise stated in an individual Surveillance Requirement.

4.0.2 Each Surveillance Requirement shall be performed within the specified time interval with:

a. A maximum allowable extension not to exceed 25% of the surveillance interval, SURVEILLANCE REQUIREMENTS (Continued)

b. A total maximum combined interval time for any 3 consecutive surveillance intervals not to exceed 3.25 times the specified surveillance interval.

4.0.3 Performance of a Surveillance Requirement within the specified time interval shall constitute compliance with OPERABILITY requirements for a Limiting Condition for Operation and associated ACTION statements unless otherwise required by the specification. Surveillance requirements do not have to be performed on inoperable equipment.

4.0.4 Entry into an OPERATIONAL CONDITION or other specified applicable state shall not be made unless the Surveillance Requirement(s) associated with the Limiting Condition for Operation have been performed within the applicable surveillance interval or as otherwise specified.

4.0.5 Surveillance Requirements for inservice inspection and testing of ASME Code Class 1, 2 & 3 components shall be applicable as follows:

a. During the time period:

1. From issuance of the Facility Operating License to the start of facility commercial operation, inservice testing of ASME Code Class 1, 2 & 3 pumps and valves shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code 1974 Edition, and Addenda through Winter 1975 except where specific written relief has been granted by the commission.

2. Following start of facility commercial operation, inservice inspection of ASME Code Class 1, 2, and 3 components and inservice testing of ASME Code Class 1, 2, and 3 pumps and valves shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR 50, Section 50.55a(g), except where specific written relief has been granted by the Commission pursuant to 10 CFR 50, Section 50.55a(g) (6) (i).

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 REACTOR PROTECTION SYSTEM RESPONSE TIME as shown in Table 3.3.1-2. Set points and interlocks are given in Table 2.2.1-1.

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

a. With the requirements for the minimum number of OPERABLE channels not satisfied for one trip system, place at least one inoperable channel in the tripped condition within one hour.

b. With the requirements for the minimum number of OPERABLE channels not satisfied for both trip systems, place at least one inoperable channel in at least one trip system* in the tripped condition within one hour and take the ACTION required by Table 3.3.1-1.

c. The provisions of Specification 3.0.3 are not applicable in OPERATIONAL CONDITION 5.

SURVEILLANCE REQUIREMENTS

4.3.1.1 Each reactor protection system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations during the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.1-1.

4.3.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed at least once per 18 months and shall include calibration of time delay relays and timers necessary for proper functioning of the trip system.

4.3.1.3 The REACTOR PROTECTION SYSTEM RESPONSE TIME of each reactor trip function of 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 logic train such that both logic trains are tested at least once per 36 months and one channel per function 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 function.

*If both channels are inoperable in one trip system, select at least one inoperable channel in that trip system to place in the tripped condition, except when this could cause the Trip Function to occur.

TABLE 3.3.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT AND INSTRUMENT NUMBER	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM NUMBER OPERABLE CHANNELS PER TRIP SYSTEM(a)	ACTION
1. Intermediate Range Monitors: (C51-IRM-K601 A,B,C,D,E,F,G,H)			
a. Neutron Flux - High	2, 5(b)	3	1
	3, 4	2	2
b. Inoperative	2, 5	3	1
	3, 4	2	2
2. Average Power Range Monitor: (C51-APRM-CH.A,B,C,D,E,F)			
a. Neutron Flux - High, 15%	2, 5(b)	2	3
b. Flow Biased Neutron Flux - High	1	2	4
c. Fixed Neutron Flux-High, 120%	1	2	4
d. Inoperative	1, 2, 5	2	5
e. Downscale	1	2	4
f. LPRM	1, 2, 5	(c)	NA
3. Reactor Vessel Steam Dome Pressure - High (B21-PS-N023 A,B,C,D)	1, 2(d)	2	6
4. Reactor Vessel Water Level - Low, Level #1 (B21-LIS-N017 A,B,C,D)	1, 2	2	6
5. Main Steam Line Isolation Valve - Closure (B21-F022 A,B,C,D and B21-F028 A,B,C,D)	1	4	4
6. Main Steam Line Radiation - High (D12-RM-K603 A,B,C,D)	1, 2(d)	2	7

TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT AND INSTRUMENT NUMBER	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM NUMBER OPERABLE CHANNELS PER TRIP SYSTEM(a)(b)	ACTION
7. Drywell Pressure - High (C71-PS-N002 A,B,C,D)	1, 2(e)	2	6
8. Scram Discharge Volume Water Level - High (C11-LSH-N013 A,B,C,D)	1, 2, 5(f)	2	5
9. Turbine Stop Valve - Closure (EHC-SVOS-1X,2X,3X,4X)	1(g)	4	8
10. Turbine Control Valve Fast Closure, Control Oil Pressure - Low (EHC-PSL-1756,1757,1758,1759)	1(g)	2	8
11. Reactor Mode Switch in Shutdown Position (C71A-SI)	1, 2, 3, 4, 5	1	9
12. Manual Scram (C71A-S3A,B)	1, 2, 3, 4, 5	1	10

TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

ACTION

ACTION 1 - In CONDITION 2, be in at least HOT SHUTDOWN within 6 hours.

In CONDITION 5, suspend all operations involving CORE ALTERATIONS or postive reactivity changes and fully insert all insertable control rods within one hour.

ACTION 2 - Lock the reactor mode switch in the Shutdown position within one hour.

ACTION 3 - In OPERATIONAL CONDITION 2, be in at least HOT SHUTDOWN within 6 hours.

In OPERATIONAL CONDITION 5, suspend all operations involving CORE ALTERATIONS or positive reactivity changes and fully insert all insertable control rods within one hour.

ACTION 4 - Be in at least STARTUP within 2 hours.

ACTION 5 - In OPERATIONAL CONDITION 1 or 2, be in at least HOT SHUTDOWN within 6 hours.

In OPERATIONAL CONDITION 5, suspend all operations involving CORE ALTERATIONS or positive reactivity changes and fully insert all insertable control rods within one hour.

ACTION 6 - Be in at least HOT SHUTDOWN within 6 hours.

ACTION 7 - Be in STARTUP with the main steam line isolation valves closed within 2 hours or in at least HOT SHUTDOWN within 6 hours.

ACTION 8 - Initiate a reduction in THERMAL POWER within 15 minutes and be at less than 30% of RATED THERMAL POWER within 2 hours.

ACTION 9 - In OPERATIONAL CONDITION 1 or 2, be in at least HOT SHUTDOWN within 6 hours.

In OPERATIONAL CONDITION 3 or 4, immediately and at least once per 12 hours verify that all control rods are fully inserted.

In OPERATIONAL CONDITION 5, suspend all operations involving CORE ALTERATIONS or positive reactivity changes and fully insert all insertable control rods within one hour.

TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

ACTION 10 - In OPERATIONAL CONDITION 1 or 2, be in at least HOT SHUTDOWN within 6 hours.

In OPERATIONAL CONDITION 3 or 4, lock the reactor mode switch in the Shutdown position within one hour.

In OPERATIONAL CONDITION 5, suspend all operations involving CORE ALTERATIONS or positive reactivity changes and fully insert all insertable control rods within one hour.

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 shutdown margin demonstrations.

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

d. These functions are not required to be OPERABLE when the reactor pressure vessel head is unbolted or removed.

e. This function is not required to be OPERABLE when PRIMARY CONTAINMENT INTEGRITY is not required.

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

g. These functions are bypassed when THERMAL POWER is less than 30% of RATED THERMAL POWER.

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

TABLE 3.3.1-2

REACTOR PROTECTION SYSTEM RESPONSE TIMES

FUNCTIONAL UNIT AND INSTRUMENT NUMBER	RESPONSE TIME (Seconds)
1. Intermediate Range Monitors (C51-IRM-K601 A,B,C,D,E,F,G,H):	
a. Neutron Flux - High*	NA
b. Inoperative	NA
2. Average Power Range Monitor* (C51-APRM-CH.A,B,C,D,E,F):	
a. Neutron Flux - High, 15%	< 0.09
b. Flow Biased Neutron Flux - High	NA
c. Neutron Flux - High, 120%	< 0.09
d. Inoperative	NA
e. Downscale	NA
f. LPRM	NA
3. Reactor Vessel Steam Dome Pressure - High (B21-PS-N023 A,B,C,D)	≤ 0.55
4. Reactor Vessel Water Level - Level #1 (B21-LIS-N017 A,B,C,D)	≤ 1.05
5. Main Steam Line Isolation Valve-Closure (B21-F022 A,B,C,D and B21-F028 A,B,C,D)	≤ 0.06
6. Main Steam Line Radiation - High (D12-RM-K603 A,B,C,D)	NA
7. Drywell Pressure - High (C71-PS-N002 A,B,C,D)	NA
8. Scram Discharge Volume Water Level - High (C11-LSH-N013 A,B,C,D)	NA
9. Turbine Stop Valve - Closure (EHC-SVOS-1X,2X,3X,4X)	≤ 0.06
10. Turbine Control Valve Fast Closure, Control Oil Pressure - Low (EHC-PSL-1756,1757,1758,1759)	≤ 0.08
11. Reactor Mode Switch in Shutdown Position (C71A-S1)	NA
12. Manual Scram (C71A-S3 A,B)	NA

*Neutron detectors are exempt from response time testing. Response time shall be measured from detector output or input of first electronic component in channel.

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.2 The isolation actuation instrumentation channels shown in Table 3.3.2-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.2-2 and with ISOLATION SYSTEM RESPONSE TIME as shown in Table 3.3.2-3.

APPLICABILITY: As shown in Table 3.3.2-1.

ACTION:

a. With an isolation actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.2-2, declare the channel inoperable and place the inoperable channel in the tripped condition until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. With the requirements for the minimum number of OPERABLE channels not satisfied for one trip system, place at least one inoperable channel in the tripped condition within one hour.

c. With the requirements for the minimum number of OPERABLE channels not satisfied for both trip systems, place at least one inoperable channel in at least one trip system* in the tripped condition within one hour and take the ACTION required by Table 3.3.2-1.

d. The provisions of Specification 3.0.3 are not applicable in OPERATIONAL CONDITION 5.

SURVEILLANCE REQUIREMENTS

4.3.2.1 Each isolation actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations during the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.2-1.

4.3.2.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed at least once per 18 months and shall include calibration of time delay relays and timers necessary for proper functioning of the trip system.

*If both channels are inoperable in one trip system, select at least one inoperable channel in that trip system to place in the tripped condition, except when this would cause the Trip Function to occur.

SURVEILLANCE REQUIREMENTS (Continued)

4.3.2.3 The ISOLATION SYSTEM RESPONSE TIME of each isolation function shown in Table 3.3.2-3 shall be demonstrated to be within its limit at least once per 18 months. Each test shall include at least one logic train such that both logic chains are tested at least once per 36 months and one channel per function 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 isolation function.

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION AND INSTRUMENT NUMBER	VALVE GROUPS OPERATED BY SIGNAL(a)	MINIMUM NUMBER OPERABLE CHANNELS PER TRIP SYSTEM(b)(c)	APPLICABLE OPERATIONAL CONDITION	ACTION
5. SHUTDOWN COOLING SYSTEM ISOLATION				
a. Reactor Vessel Water - Low, Level #1 (B21-LIS-N017A,B,C,D)	2, 6, 7, 8	2	1, 2, 3	27
b. Reactor Steam Dome Pressure - High (B32-PS-N018A,B)	7, 8	1	1, 2, 3	27

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

ACTIONS

ACTION 20 - Be in at least HOT SHUTDOWN within 6 hours and in COLD SHUTDOWN within the following 30 hours.

ACTION 21 - Be in at least STARTUP with the main steam line isolation valves closed within 2 hours or be in at least HOT SHUTDOWN within 6 hours and in COLD SHUTDOWN within the next 30 hours.

ACTION 22 - Be in at least STARTUP within 2 hours.

ACTION 23 - Establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within one hour.

ACTION 24 - Isolate the reactor water cleanup system.

ACTION 25 - Close the affected system isolation valves and declare the affected system inoperable.

ACTION 26 - Verify power availability to the bus at least once per 12 hours.

ACTION 27 - Deactivate the shutdown cooling supply and reactor vessel head spray isolation valves in the closed position until the reactor steam dome pressure is within the specified limits.

NOTES

* When handling irradiated fuel in the secondary containment.

a. See Specification 3.6.3.1, Table 3.6.3.1-1 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. With 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 3.3.2-1 for that Trip Function shall be taken.

d. Trips the mechanical vacuum pumps.

e. A channel is OPERABLE if 2 of 4 instruments in that channel are OPERABLE.

f. With reactor steam pressure $\geq$ 500 psig.

g. Closes only RWCU outlet isolation valve.

h. Alarm only.

TABLE 4.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION AND INSTRUMENT NUMBER	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS IN WHICH SURVEILLANCE REQUIRED
5. SHUTDOWN COOLING SYSTEM ISOLATION				
a. Reactor Vessel Water - Low, Level #1 (B21-LIS-N017A,B,C,D)	D	M	R	1, 2, 3
b. Reactor Steam Dome Pressure - High (B32-PS-N018A,B)	NA	S/U*, M	R	1, 2, 3

*If not performed within the previous 31 days.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3 The Emergency Core Cooling System (ECCS) actuation instrumentation shown in Table 3.3.3-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.3-2 and with EMERGENCY CORE COOLING SYSTEM RESPONSE TIME as shown in Table 3.3.3-3.

APPLICABILITY: As shown in Table 3.3.3-1.

ACTION:

a. With an ECCS actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.3-2, declare the channel inoperable and place the inoperable channel in the tripped condition until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. With one or more ECCS actuation instrumentation channels inoperable, take the ACTION required by Table 3.3.3-1.

c. The provisions of Specification 3.0.3 are not applicable in OPERATIONAL CONDITION 5.

SURVEILLANCE REQUIREMENTS

4.3.3.1 Each ECCS actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations during the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.3-1.

4.3.3.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed at least once per 18 months and shall include calibration of time delay relays and timers necessary for proper functioning of the trip system.

4.3.3.3 The ECCS RESPONSE TIME of each ECCS function shown in Table 3.3.3-3 shall be demonstrated to be within the limit at least once per 18 months. Each test shall include at least one logic train such that both logic trains are tested at least once per 36 months and one channel per function 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 ECCS function.

TABLE 3.3.3-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION AND INSTRUMENT NUMBER	MINIMUM NUMBER OPERABLE CHANNELS PER TRIP SYSTEM	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. CORE SPRAY SYSTEM			
a. Reactor Vessel Water Level - Low, Level #3 (B21-LIS-N031A,B,C,D)	2	1, 2, 3, 4, 5	30
b. Reactor Steam Dome Pressure - Low (Injection Permissive) (B21-PS-N021A,B,C,D)	2	1, 2, 3, 4, 5	31
c. Drywell Pressure - High (E11-PS-N011A,B,C,D)	2	1, 2, 3	30
d. Time Delay Relay	1	1, 2, 3, 4, 5	31
e. Bus Power Monitor# (E21-K1A,B)	1/bus	1, 2, 3, 4, 5	32
2. LPCI MODE OF RHR SYSTEM			
a. Drywell Pressure - High (E11-PS-N011A,B,C,D)	2	1, 2, 3	30
b. Reactor Vessel Water Level - Low, Level #3 (B21-LIS-N031A,B,C,D)	2	1, 2, 3, 4*, 5*	30
c. Reactor Vessel Shroud Level (Drywell Spray Permissive) (B21-LITS-N036 and B21-LITS-N037)	1	1, 2, 3, 4*, 5*	31
d. Reactor Steam Dome Pressure - Low (Injection Permissive) (B21-PS-N021A,B,C,D)			
1. RHR Pump Start and LPCI Injection Valve Actuation	2	1, 2, 3, 4*, 5*	31
2. Recirculation Loop Pump Discharge Valve Actuation	2	1, 2, 3, 4*, 5*	31
e. RHR Pump Start - Time Delay Relay	1	1, 2, 3, 4*, 5*	31
f. Bus Power Monitor# (E11-K106A,B)	1/bus	1, 2, 3, 4*, 5*	32
3. HPCI SYSTEM			
a. Reactor Vessel Water Level - Low, Level #2 (B21-LIS-N031A,B,C,D)	2	1, 2, 3	30
b. Drywell Pressure - High (E11-PS-N011A,B,C,D)	2	1, 2, 3	30
c. Condensate Storage Tank Level-Low (E41-LS-N002, E41-LS-N003)	2**	1, 2, 3	33
d. Suppression Chamber Water Level-High (E41-LSH-N015A,B)	2**	1, 2, 3	33
e. Bus Power Monitor# (E41-K55 and E41-K56)	1/bus	1, 2, 3	32

TABLE 3.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION AND INSTRUMENT NUMBER	MINIMUM NUMBER OPERABLE CHANNELS PER TRIP SYSTEM	APPLICABLE OPERATIONAL CONDITIONS	ACTION
4. ADS			
a. Drywell Pressure - High, coincident with (E11-PS-N010A,B,C,D)	2	1, 2, 3	30
b. Reactor Vessel Water Level - Low, Level #3 (B21-LIS-N031A,B,C,D)	2	1, 2, 3	30
c. ADS Timer (B21-TDPU-K5A,B)	1	1, 2, 3	31
d. Core Spray Pump Discharge Pressure - High (Permissive) (E21-PS-N008A,B and E21-PS-N009A,B)	2	1, 2, 3	31
e. RHR (LPCI MODE) Pump Discharge Pressure - High (Permissive) (E11-PS-N016A,B,C,D and E11-PS-N020A,B,C,D)	2/pump	1, 2, 3	31
f. Bus Power Monitor# (B21-K1A,B)	1/bus	1, 2, 3	32

	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE OPERATIONAL CONDITIONS	ACTION
5. LOSS OF POWER					
a. 4.16 kv Emergency Bus Undervoltage (Loss of Voltage)	1/bus	1/bus	1/bus	1, 2, 3, 4##, 5##	34
b. 4.16 kv Emergency Bus Undervoltage (Degraded Voltage)	3/bus	2/bus	2/bus	1, 2, 3, 4##, 5##	35

*Not applicable when two core spray system subsystems are OPERABLE per Specification 3.5.3.1.
**Provides signal to HPCI pump suction valves only.
#Alarm only.
##Required when ESF equipment is required to be OPERABLE.

TABLE 3.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

ACTION

ACTION 30 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement:

a. For one trip system, place at least one inoperable channel in the tripped condition within one hour or declare the associated ECCS inoperable.

b. For both trip systems, declare the associated ECCS inoperable.

ACTION 31 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, declare the associated ECCS inoperable.

ACTION 32 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, verify bus power availability at least once per 12 hours or declare the associated ECCS inoperable.

ACTION 33 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, place at least one inoperable channel in the tripped condition within one, hour or declare the HPCS system inoperable.

ACTION 34 - With the number of OPERABLE channels less than the Total Number of Channels, declare the associated emergency diesel generator inoperable and take the ACTION required by Specification 3.8.1.1 or 3.8.1.2, as appropriate.

ACTION 35 - With the number of OPERABLE channels one less than the Total Number of Channels, place the inoperable channel in the tripped condition within 1 hour; operation may then continue until performance of the next required CHANNEL FUNCTIONAL TEST.

TABLE 3.3.3-2

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION AND INSTRUMENT NUMBER	TRIP SETPOINT	ALLOWABLE VALUE
1. CORE SPRAY SYSTEM		
a. Reactor Vessel Water Level - Low, Level #3 (B21-LIS-N031A,B,C,D)	$\geq$ -147.5 inches	$\geq$ -147.5 inches
b. Reactor Steam Dome Pressure - Low (B21-PS-N021A,B,C,D)	410 $\pm$ 15 psig	410 $\pm$ 15 psig
c. Drywell Pressure - High (E11-PS-N011A,B,C,D)	$\leq$ 2 psig	$\leq$ 2 psig
d. Time Delay Relay	14 $\leq$ t $\leq$ 16 secs	14 $\leq$ t $\leq$ 16 secs
e. Bus Power Monitor (E21-K1A,B)	NA	NA
2. LPCI MODE OF RHR SYSTEM		
a. Drywell Pressure - High (E11-PS-N011A,B,C,D)	$\leq$ 2 psig	$\leq$ 2 psig
b. Reactor Vessel Water Level - Low, Level #3 (B21-LIS-N031A,B,C,D)	$\geq$ -147.5 inches	$\geq$ -147.5 inches
c. Reactor Vessel Shroud Level (B21-LITS-N036 and B21-LITS-N037)	$\geq$ 39" below TAF*	$\geq$ 39" below TAF*
d. Reactor Steam Dome Pressure - Low (B21-PS-N021A,B,C,D)		
1. RHR Pump Start and LCPI Injection Valve Actuation	410 $\pm$ 15 psig	410 $\pm$ 15 psig
2. Recirculation Loop Pump Discharge Valve Actuation	310 $\pm$ 15 psig	310 $\pm$ 15 psig
e. RHR Pump Start - Time Delay Relay	9 $\leq$ t $\leq$ 11 seconds	9 $\leq$ t $\leq$ 11 seconds
f. Bus Power Monitor (E11-K106A,B)	NA	NA

*Top of the active fuel.

TABLE 3.3.3-2 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION AND INSTRUMENT NUMBER	TRIP SETPOINT	ALLOWABLE VALUE
3. HPCI SYSTEM		
a. Reactor Vessel Water Level - Low, Level #2 (B21-LIS-N031A,B,C,D)	$\geq$ -38 inches	$\geq$ -38 inches
b. Drywell Pressure-High (E11-PS-N011A,B,C,D)	$\leq$ 2 psig	$\leq$ 2 psig
c. Condensate Storage Tank Level - Low (E41-LS-N002, E41-LS-N003)	$\geq$ 23'4"	$\geq$ 23'4"
d. Suppression Chamber Water Level - High* (E41-LSH-N015A,B,)	$\leq$ -2 feet	$\leq$ -2 feet
e. Bus Power Monitor (E41-K55 and E41-K56)	NA	NA
4. ADS		
a. Drywell Pressure-High (E11-PS-N010A,B,C,D)	$\leq$ 2 psig	$\leq$ 2 psig
b. Reactor Vessel Water Level - Low, Level #3 (B21-LIS-N031A,B,C,D)	$\geq$ -147.5 inches	$\geq$ -147.5 inches
c. ADS Timer (B21-TDPU-K5A,B)	$\leq$ 120 seconds	$\leq$ 120 seconds
d. Core Spray Pump Discharge Pressure - High (E21-PS-N008A,B and E21-PS-N009A,B)	$\geq$ 100 psig	$\geq$ 100 psig
e. RHR (LPCI MODE) Pump Discharge Pressure - High (E11-PS-N016A,B,C,D and E11-PS-N020A,B,C,D)	$\geq$ 100 psig	$\geq$ 100 psig
f. Bus Power Monitor (B21-K1A,B)	NA	NA

*Suppression chamber water level zero is the torus centerline minus 1 inch.

TABLE 3.3.3-2 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

FUNCTIONAL UNIT	TRIP VALUE	ALLOWABLE VALUES
5. LOSS OF POWER		
a. 4.16 kv Emergency Bus Undervoltage (Loss of Voltage)*	a. 4.16 kv Basis - 2940 ± 161 volts b. 120 v Basis - 84 ± 4.6 volts c. ≤ 10 sec. time delay	2940 ± 315 volts 84 ± 9 volts ≤ 10 sec. time delay
b. 4.16 kv Emergency Bus Undervoltage (Degraded Voltage)	a. 4.16 kv Basis - 3727 ± 9 volts b. 120 v Basis - 106.5 ± 0.25 volts c. 10 ± 0.5 sec. time delay	3727 ± 21 volts 106.5 ± 0.60 volts 10 ± 1.0 sec. time delay

*This is an inverse time delay voltage relay. The voltages shown are the maximum that will not result in a trip. Lower voltage conditions will result in decreased trip times.

TABLE 3.3.3-3

EMERGENCY CORE COOLING SYSTEM RESPONSE TIMES

ECCS	RESPONSE TIME (Seconds)
1. CORE SPRAY SYSTEM	$\leq$ 27
2. LPCI MODE of RHR SYSTEM	$\leq$ 40
3. HIGH PRESSURE COOLANT INJECTION SYSTEM	$\leq$ 30
4. AUTOMATIC DEPRESSURIZATION SYSTEM	NA
5. LOSS OF POWER	NA

TABLE 4.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS IN WHICH SURVEILLANCE REQUIRED
5. LOSS OF POWER				
a. 4.16 kv Emergency Bus Undervoltage (Loss of Voltage)	NA	NA	R	1, 2, 3, 4*, 5*
b. 4.16 kv Emergency Bus Undervoltage (Degraded Voltage)	S	M	R	1, 2, 3, 4*, 5*

*Required when ESF equipment is required to be OPERABLE.

3/4.7.1 SERVICE WATER SYSTEMS

RESIDUAL HEAT REMOVAL SERVICE WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.1 Two independent Residual Heat Removal Service Water (RHRSW) System subsystems shall be OPERABLE with each subsystem comprised of:

a. Two pumps, and

b. An OPERABLE flow path for heat removal capable of taking suction from the intake canal via the service water system and transferring the water through an RHR heat exchanger.

APPLICABILITY: CONDITIONS 1, 2 and 3.

ACTION:

a. With one RHRSW pump inoperable, operation may continue and the provisions of Specification 3.0.4 are not applicable; restore the inoperable pump to OPERABLE status within 31 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one RHRSW subsystem inoperable, operation may continue and the provisions of Specification 3.0.4 are not applicable; restore the inoperable subsystem 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.

c. With both RHRSW subsystems inoperable, restore at least one subsystem 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

4.7.1.1 Each residual heat removal service water subsystem shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve in the flow path that is not locked, sealed or otherwise secured in position, is in its correct position, and

b. At least once per 92 days by verifying that each pump develops a pump ΔP of at least 232 psi at a flow of 4000 gpm measured through the heat exchanger with a minimum suction pressure of 20 psig.

SERVICE WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.2 The service water system nuclear header shall be OPERABLE with at least three OPERABLE service water pumps.

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

ACTION:

a. In CONDITION 1, 2, or 3:

1. With only two service water pumps OPERABLE, restore at least three pumps 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.

2. With only one service water pump OPERABLE, restore at least two pumps to OPERABLE status within 72 hours and restore at least three pumps to OPERABLE status within 7 days from the time of the initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In Condition 4 or 5, with only one service water pump OPERABLE, restore at least two service water pumps to OPERABLE status within 7 days or declare the core spray system, the LPCI system and the diesel generator inoperable and take the ACTION required by Specifications 3.5.3.1, 3.5.3.2 and 3.8.1.2.

SURVEILLANCE REQUIREMENTS

4.7.1.2 The service water system shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power operated or automatic) servicing safety related equipment that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. At least once per 18 months during shutdown, by verifying that each automatic valve servicing safety related equipment actuates to its correct position on the appropriate ECCS actuation test signals.

SURVEILLANCE REQUIREMENTS

4.7.7.5 Each of the above required foam systems shall be demonstrated OPERABLE:

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

b. At least once per 18 months by:

1. 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 simulated actuation 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.

2. A visual inspection of the spray headers to verify their integrity.

3. A visual inspection of each nozzle's spray area to verify that the spray pattern is not obstructed.

4. Conducting a performance evaluation of the concentrate.

3/4.7.8 FIRE BARRIER PENETRATIONS

LIMITING CONDITIONS FOR OPERATION

3.7.8 All fire barrier penetrations, including cable penetration barriers, fire doors and fire dampers, in fire zone boundaries protecting safety related areas shall be functional.

APPLICABILITY: At all times.

ACTION:

a. With one or more of the above required fire barrier penetrations non-functional, within one hour establish a continuous fire watch on at least one side of the affected penetration or verify the OPERABILITY of fire detectors on at least one side of the non-functional fire barrier and establish an hourly fire watch patrol. Restore the non-functional fire barrier penetration(s) to functional status within 7 days or, in lieu of any other report required by Specification 6.9.1, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 30 days outlining the action taken, the cause of the non-functional penetration and plans and schedule for restoring the fire barrier penetration(s) to functional status.

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

SURVEILLANCE REQUIREMENTS

4.7.8 Each of the above required fire barrier penetrations shall be verified to be functional:

a. At least once per 18 months by a visual inspection, and

b. Prior to restoring a fire barrier penetration to functional status following repairs or maintenance, by performance of a visual inspection of the affected fire barrier penetration.

3/4.0 APPLICABILITY

BASES

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.

3.0.1 This specification states the applicability of each specification in terms of defined OPERATIONAL 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 ACTION to be taken for circumstances not directly provided for in the ACTION statements and whose occurrence would violate the intent of specification. For example, Specification 3.5.1 calls for the HPCI to be OPERABLE and specifies explicit requirements if it become inoperable. Under the terms of Specification 3.0.3 if the required additional systems are not OPERABLE, the facility is to be placed in HOT SHUTDOWN within the next 6 hours and be in COLD SHUTDOWN within the following 30 hours. The unit shall be brought to the required OPERATIONAL CONDITION within the required times by promptly initiating and carrying out an orderly shutdown. It is intended that this guidance also apply whenever an ACTION statement requires a unit to be in STARTUP within 2 hours or in HOT SHUTDOWN within 6 hours.

3.0.4 This specification provides that entry into an OPERABLE 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 insure that facility 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.

BASES

4.0.1 This specification provides that surveillance activities necessary to insure the Limiting Conditions for Operation are met and will be performed during the OPERATIONAL CONDITIONS for which the Limiting Conditions for Operation are applicable. Provisions for additional surveillance activities to be performed without regard to the applicable OPERATIONAL CONDITIONS are provided in the individual Surveillance Requirements.

4.0.2 The provisions of this specification provide allowable tolerances for performing surveillance activities beyond those specified in the nominal surveillance interval. These tolerances are necessary to provide operational flexibility because of scheduling and performance considerations. considerations. The phrase "at least" associated with a surveillance frequency does not negate this allowable tolerance value and permits the performance of more frequent surveillance activities.

The tolerance values, taken either individually or consecutively over 3 test intervals, are sufficiently restrictive to ensure that the reliability associated with the surveillance activity is not significantly degraded beyond that obtained from the nominal specified interval.

4.0.3 The provisions of this specification set forth the criteria for determination of compliance with the OPERABILITY requirements of the Limiting Conditions for Operation. Under this criteria, equipment, systems or components are assumed to be OPERABLE if the associated surveillance activities have been satisfactorily performed within the specified time interval. Nothing in this provision is to be construed as defining equipment, systems or components OPERABLE, when such items are found or known to be inoperable although still meeting the Surveillance Requirements.

4.0.4 This specification ensures that surveillance activities associated with a Limiting Condition for Operation have been performed within the specified time interval prior to entry into an applicable CONDITION. The intent of this provision is to ensure that surveillance activities have been satisfactorily demonstrated on a current basis as required to meet the OPERABILITY requirements of the Limiting Condition for Operation.

Under the terms of this specification, for example, during initial plant startup or following extended plant outage, the applicable surveillance activities must be performed within the stated surveillance interval prior to placing or returning the system or equipment into OPERABLE status. Exceptions to some surveillance activities have been provided for in individual specifications.

3/4.7.5 HYDRAULIC SNUBBERS (Continued)

To provide further assurance of snubber reliability, a representative sample of the installed snubbers will be functionally tested during plant shutdowns at 18 month intervals. These tests will include stroking of the snubbers to verify proper piston movement, lock-up and bleed. Observed failures of these sample snubbers will require functional testing of additional units. To minimize personnel exposures, snubbers installed in high radiation zones or in especially difficult to remove locations may be exempted from these functional testing requirements provided the OPERABILITY of these snubbers was demonstrated during functional testing at either the completion of their fabrication or at a subsequent date.

3/4.7.6 SEALED SOURCE CONTAMINATION

The limitations on sealed source removable contamination ensure that the total body or individual organ irradiation does not exceed allowable limits in the event of ingestion or inhalation of the source material. The limitations on removable contamination for sources requiring leak testing, including alpha emitters, is based on 10 CFR 70.39(c) limits for plutonium. Quantities of interest to this specification which are exempt from the leakage testing are consistent with the criteria of 10 CFR Part 30.11-20 and 70.19. Leakage from sources excluded from the requirements of this specification is not likely to represent more than one maximum permissible body burden for total body irradiation if the source material is inhaled or ingested.

3/4.7.7 FIRE SUPPRESSION SYSTEMS

The OPERABILITY of the fire suppression systems ensures that adequate fire suppression capability is available to confine and extinguish fires occuring in any portion of the facility where safety related equipment is located. The fire suppression system consists of the water system, spray and/or sprinklers, CO_2, and fire hose stations. The collective capability of the fire suppression systems is adequate to minimize potential damage to safety related equipment and is a major element in the facility fire protection program.

In the event that portions of the fire suppression systems are inoperable, alternate backup fire fighting equipment is required to be made available in the affected areas until the inoperable equipment is restored to service.

3/4.7.7 FIRE SUPPRESSION SYSTEMS (Continued)

In the event the fire suppression water system becomes inoperable, immediate corrective measures must be taken since this system provides the major fire suppression capability of the plant. The requirement for a twenty-four hour report to the Commission provides for prompt evaluation of the acceptability of the corrective measures to provide adequate fire suppression capability for the continued protection of the nuclear plant.

3/4.7.8 FIRE BARRIER PENETRATIONS

The functional integrity of the fire barrier penetrations ensures that fires will be confined or adequately retarded from spreading to adjacent portions of the facility. This design feature minimizes the possibility of a single fire rapidly involving several areas of the facility prior to detection and extinguishment. The fire barrier penetrations are a passive element in the facility fire protection program and are subject to periodic inspections.

The barrier penetrations, including cable penetration barriers, fire doors and dampers are considered functional when the visually observed condition is the same as the as-designed condition. For those fire barrier penetrations that are not in the as-designed condition, an evaluation shall be performed to show that the modification has not degraded the fire rating of the fire barrier penetration.

During periods of time when the barriers are not functional, either, 1) a continuous fire watch is required to be maintained in the vicinity of the affected barrier, or 2) the fire detectors on at least one side of the affected barrier must be verified OPERABLE and a hourly fire watch patrol established until the barrier is restored to functional status.

3/4.10 SPECIAL TEST EXCEPTIONS

BASES

3/4.10.1 PRIMARY CONTAINMENT INTEGRITY

The requirement for PRIMARY CONTAINMENT INTEGRITY is removed during the period when open vessel tests are being performed during low power PHYSICS TESTS.

3/4.10.2 ROD SEQUENCE CONTROL SYSTEM

In order to perform the tests required in the Technical Specifications it is necessary to bypass the sequence restraints on control rod movement. The additional surveillance requirements ensure that the specifications on heat generation rates and shutdown margin requirements are not exceeded during the period when these tests are being performed.

3/4.10.3 SHUTDOWN MARGIN DEMONSTRATIONS

Performance of shutdown margin demonstrations with the vessel head removed requires additional restrictions in order to ensure that criticality does not occur. These additional restrictions are specified in this LCO.

3/4.10.4 RECIRCULATION LOOPS

This special test exception permits reactor criticality under no flow conditions and is required to perform certain startup and PHYSICS TESTS while at low THERMAL POWER levels.

6.1 RESPONSIBILITY

6.1.1 The General Manager shall be responsible for overall facility operation and shall delegate in writing the succession to this responsibility during his absence.

6.2 ORGANIZATION

OFFSITE

6.2.1 The offsite organization for facility management and technical support shall be as shown on Figure 6.2.1-1.

FACILITY STAFF

6.2.2 The Facility organization shall be as shown on Figures 6.2.2-1 and 6.2.2-2 and:

a. Each on duty shift shall be composed of at least the minimum shift crew composition shown in Table 6.2.2-1.

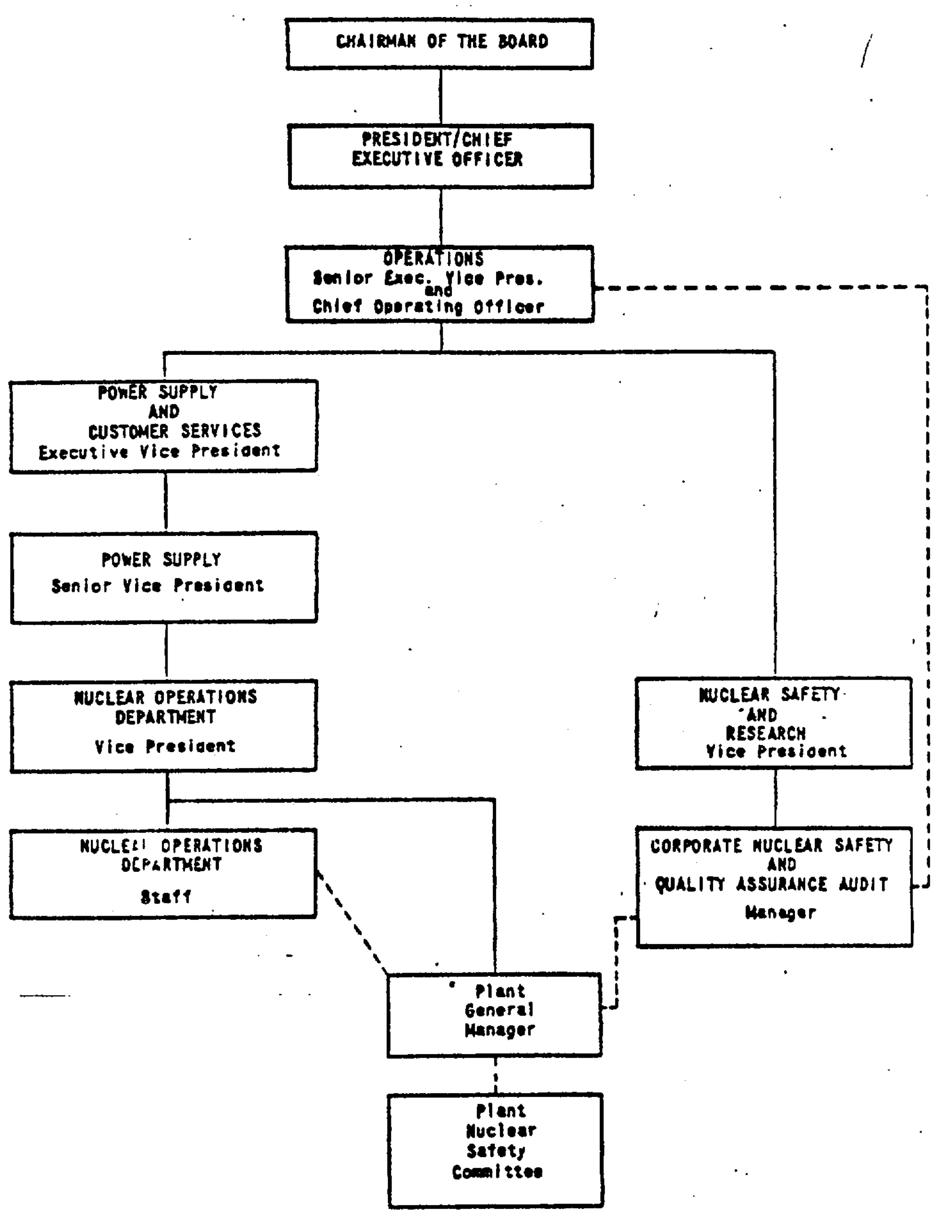
b. At least one licensed Operator shall be in the control room for each reactor containing fuel.

c. At least two licensed Operators shall be present in the control room for each reactor in the process of start-up, scheduled reactor shutdown and during recovery from reactor trips.

d. An individual qualified to implement radiation protection procedures shall be on site when fuel is in either reactor.

e. All CORE ALTERATIONS shall be directly supervised by either a licensed Senior Reactor Operator or Senior Reactor Operator Limited to Fuel Handling who has no other concurrent responsibilities during this operation.

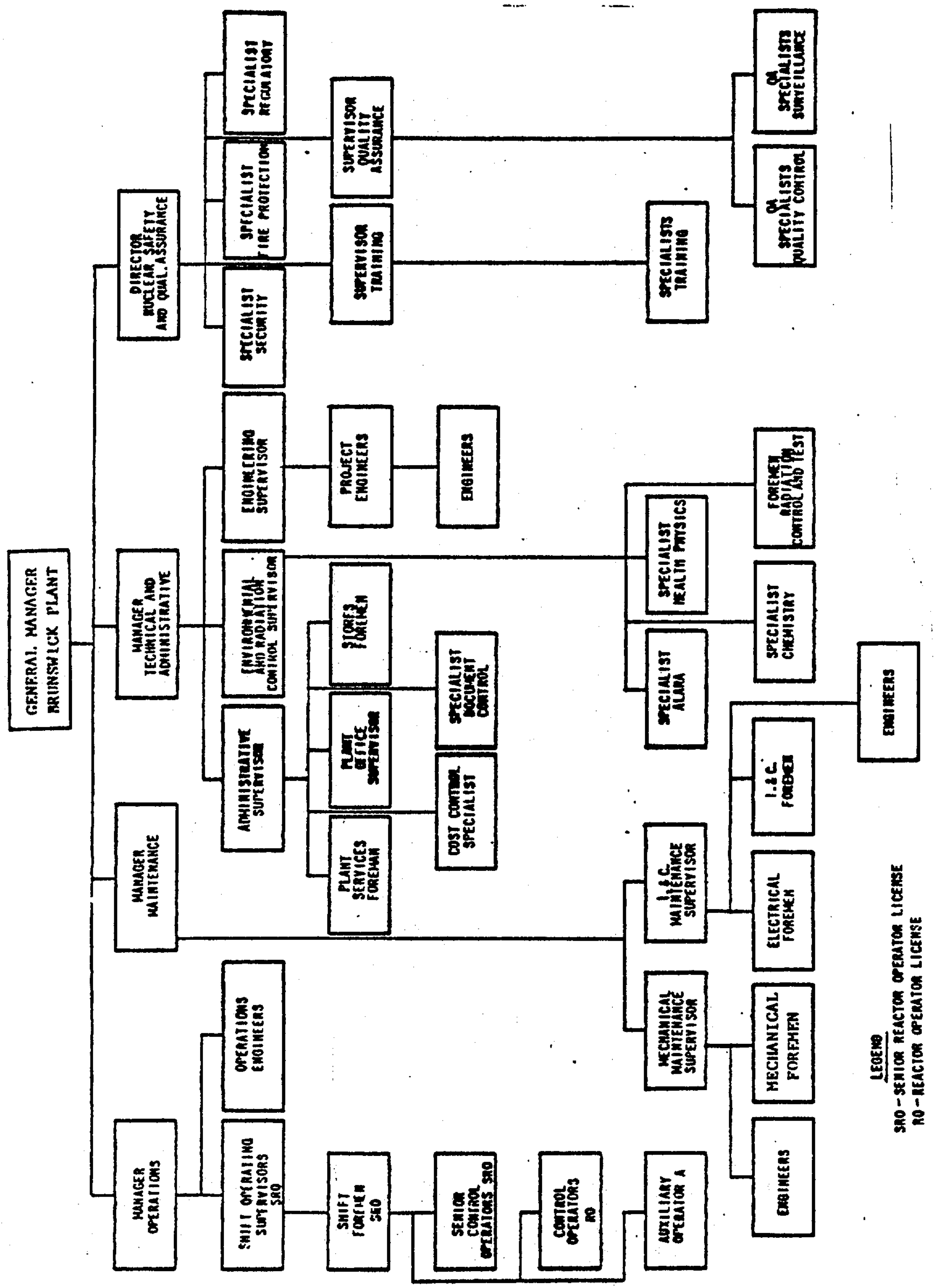
f. A Fire Brigade of at least five members shall be maintained onsite at all times. The Fire Brigade shall not include the minimum shift crew shown in Table 6.2.2-1 or any personnel required for other essential functions during a fire emergency.



*Responsible for performance and monitoring of Fire Protection Program.

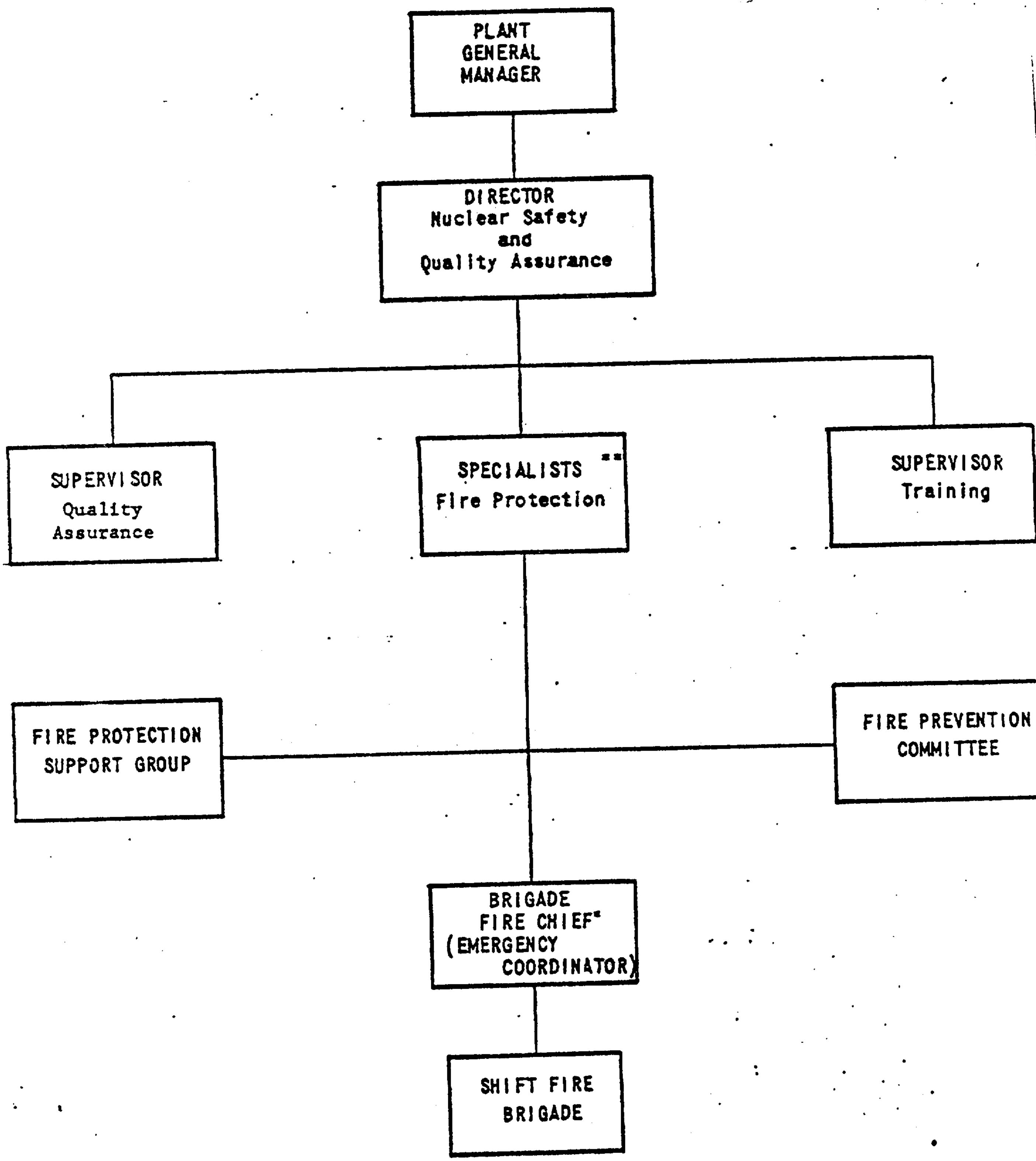
MANAGEMENT ORGANIZATION CHART

FIGURE 6.2-1



FACILITY ORGANIZATION

Figure 6.2.2-1



PLANT FIRE PROTECTION ORGANIZATION

*Number of Brigade Fire Chiefs varies with shift organization.
**One Engineer is assigned the duties of the plant fire chief.

FIGURE 6.2.2-2

TABLE 6.2.2-1

MINIMUM SHIFT CREW COMPOSITION#

Condition of Unit 1 - Unit 2 in CONDITION 1, 2 or 3

LICENSE CATEGORY	APPLICABLE OPERATIONAL CONDITIONS	
	1, 2, 3	4 & 5
SOL**	2	2*
OL**	3	2
Non-Licensed	4	3

Condition of Unit 1 - Unit 2 in CONDITION 4 or 5

LICENSE CATEGORY	APPLICABLE OPERATIONAL CONDITIONS	
	1, 2, 3	4 & 5
SOL**	2	1*
OL**	2	2
Non-Licensed	3	3

Condition of Unit 1 - No Fuel in Unit 2

LICENSE CATEGORY	APPLICABLE OPERATIONAL CONDITIONS	
	1, 2, 3	4 & 5
SOL	1	1*
OL	2	1
Non-Licensed	2	1

* Does not include the licensed Senior Reactor Operator or Senior Reactor Operator Limited to Fuel Handling, supervising CORE ALTERATIONS.

**Assumes each individual is licensed on both plants.

Shift crew composition, including an individual qualified in radiation protection procedures, may be less than the minimum requirements 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 Table 6.2.2-1.

6.3 FACILITY STAFF QUALIFICATIONS

6.3.1 Each member of the facility staff shall meet or exceed the minimum qualifications of ANSI N18.1-1971 for comparable position, except for the Environmental and Radiation Control Supervisor who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975.

6.4 TRAINING

6.4.1 A retraining and replacement training program for the facility staff shall be maintained under the direction of the Training Supervisor and shall meet or exceed the requirements and recommendations of Section 5.5 of ANSI N18.1-1971 and Appendix "A" of 10 CFR Part 55.

6.4.2 A training program for the Fire Brigade shall be maintained under the direction of the Plant Fire Chief and shall meet or exceed the requirements of Section 27 of the NFPA Code-1975.

6.5 REVIEW AND AUDIT

6.5.1 PLANT NUCLEAR SAFETY COMMITTEE (PNSC)

FUNCTION

6.5.1.1 The PNSC shall function to advise the General Manager on all matters related to nuclear safety.

COMPOSITION

6.5.1.2 The PNSC shall be composed of the:

Chairman:	Plant General Manager
Vice Chairman:	Operations Manager, Maintenance Manager, Technical - Administrative Manager or Director-Nuclear Safety and QA
Secretary:	Administrative Supervisor
Member:	Maintenance Supervisor (I&C)
Member:	Maintenance Supervisor (Mechanical)
Member:	Engineering Supervisor
Member:	Environmental and Radiation Control Supervisor
Member:	Quality Assurance Supervisor
Member:	Shift Operating Supervisors
Member:	Training Supervisor

ALTERNATES

6.5.1.3 All alternate members shall be appointed in writing by the PNSC Chairman to serve on a temporary basis; however, no more than two alternates shall participate as voting members in PNSC activities at any one time.

MEETING FREQUENCY

6.5.1.4 The PNSC shall meet at least once per calendar month and as convened by the PNSC Chairman or his designated alternate.

QUORUM

6.5.1.5 A quorum of the PNSC shall consist of the Chairman or Vice Chairman and three members including alternates.

RESPONSIBILITIES

6.5.1.6 The PNSC shall be responsible for:

a. Review of 1) all procedures required by Specification 6.8 and changes thereto, 2) any other proposed procedures or changes thereto as determined by the General Manager to affect nuclear safety.

b. Review of all proposed tests and experiments that affect nuclear safety.

c. Review of all proposed changes to Technical Specifications.

d. Review of all proposed changes or modifications to plant systems or equipment that affect nuclear safety.

e. Investigation of all violations of the Technical Specifications including the preparation and forwarding of reports covering evaluation and recommendations to prevent recurrence to the Vice President - Nuclear Operations and to the Manager - Corporate Nuclear Safety and Quality Assurance Audit.

f. Review of all events requiring 24 hour notification to the Commission.

g. Review of facility operations to detect potential safety hazards.

h. Performance of special reviews, investigations and reports thereon as requested by the Manager - Corporate Nuclear Safety and Quality Assurance Audit.

i. Review of the Plant Security Plan and implementing procedures.

j. Review of the Emergency Plan and implementing procedures.

AUTHORITY

6.5.1.7 The PNSC shall:

a. Recommend to the General Manager written approval or disapproval of items considered under 6.5.1.6(a) through (d) above.

b. Render determinations in writing with regard to whether or not each item considered under 6.5.1.6(a) through (e) above constitutes an unreviewed safety question.

c. Provide written notification within 24 hours to the Vice President - Nuclear Operations and the Manager - Corporate Nuclear Safety and Quality Assurance Audit of disagreement between the PNSC and the General Manager; however, the General Manager shall have responsibility for resolution of such disagreements pursuant to 6.1.1 above.

RECORDS

6.5.1.8 The PNSC shall maintain written minutes of each meeting that, at a minimum, document the results of all PNSC activities performed under the responsibility and authority provisions of these technical specifications, and copies shall be provided to the Vice President - Nuclear Operations and to the Manager - Corporate Nuclear Safety and Quality Assurance Audit.

6.5.2 CORPORATE NUCLEAR SAFETY AND QUALITY ASSURANCE AUDIT SECTION (CNS & QAAS)

RESPONSIBILITY

6.5.2.1 The Manager - Corporate Nuclear Safety and Quality Assurance Audit, under the Vice President - Nuclear Safety and Research, is charged with the overall responsibility for administering the independent off-site review and quality assurance audit programs as follows:

a. Approves selection of the individuals to conduct off-site safety reviews and quality assurance audits.

b. Has access to the plant operating records and operating personnel in performing the independent reviews and quality assurance audits.

c. Prepares and retains written records of review and audits.

d. Assures independent safety reviews are conducted on all items required by Section 6.5.3.3 and quality assurance audits cover all items included in Section 6.5.4.1.

e. Distributes reports, records of PNSC meetings, and other records to the appropriate managers and individuals assigned to conduct the off-site safety reviews and quality assurance audits.

6.5.3 CORPORATE NUCLEAR SAFETY UNIT (CNSU)

FUNCTION

6.5.3.1 The Corporate Nuclear Safety Unit of the Corporate Nuclear Safety and Quality Assurance Audit Section shall provide independent off-site review of significant plant changes, tests, and procedures; verify that reportable occurrences are promptly investigated and corrected in a manner which reduces the probability of recurrence of such events; and detect trends which may not be apparent to a day-to-day observer.

PERSONNEL

6.5.3.2

a. Personnel assigned responsibility for independent reviews shall be specified in technical disciplines, and shall collectively have the experience and competence required to review problems in the following areas:

   1. Nuclear power plant operations
   2. Nuclear engineering
   3. Chemistry and radiochemistry
   4. Metallurgy
   5. Instrumentation and control
   6. Radiological safety
   7. Mechanical and electrical engineering
   8. Administrative controls
   9. Seismic and environmental
   10. Quality assurance practices

b. The following minimum experience requirements shall be established for those persons involved in the independent off-site safety review program:

   1. Manager of CNS and QAAS - Bachelor of Science in engineering or related field and ten (10) years related experience including five (5) years involvement with operation and/or design of nuclear power plants.

   2. Reviewers - Bachelor of Science in engineering or related field or equivalent and five (5) years related experience including three (3) years involvement with operation and/or design of nuclear power plants.

PERSONNEL (Continued)

c. An individual may possess competence in more than one specialty area. If sufficient expertise is not available within the Corporate Nuclear Safety Unit, competent individuals from other Carolina Power and Light Company organizations or outside consultants shall be utilized in performing independent off-site reviews and investigations.

d. At least three persons, qualified as discussed in Specification 6.5.2.3.b, shall review each item submitted under the requirements of Section 6.5.3.3.

e. Independent safety reviews shall be performed by personnel not directly involved with the activity or responsible for the activity.

SUBJECTS REQUIRING INDEPENDENT REVIEW

6.5.3.3 The following subjects shall be reviewed by the Corporate Nuclear Safety Unit:

a. Written safety evaluations of changes in the facility as described in the Safety Analysis Report, changes in procedures as described in the Safety Analysis Report and tests or experiments not described in the Safety Analysis Report which are completed without prior NRC approval under the provisions of 10 CFR 50.59(a)(1). This review is to verify that such changes, tests, or experiments did not involve a change in the technical specifications or an unreviewed safety question as defined in 10 CFR 50.59(a)(2).

b. Proposed changes in procedures, proposed changes in the facility, or proposed tests or experiments, any of which involves a change in the Technical Specifications or an unreviewed safety question pursuant to 10 CFR 50.59(c). Matters of this kind shall be referred to the Corporate Nuclear Safety Unit by the Plant Nuclear Safety Committee following its review, or by other functional organizational units within Carolina Power & Light Company prior to implementation.

c. Proposed changes to the Technical Specifications or this operating license.

SUBJECTS REQUIRING INDEPENDENT REVIEW (Continued)

d. Violations, deviations and reportable events, which require reporting to the NRC within 24 hours, and as defined in the plant technical specifications such as:

   1. Violations of applicable codes, regulations, orders, Technical Specifications, license requirements or internal procedures or instructions having safety significance; and

   2. Significant operating abnormalities or deviations from normal or expected performance of plant safety-related structures, systems, or components.

   Review of events covered under this paragraph shall include the results of any investigations made and the recommendations resulting from such investigations to prevent or reduce the probability of recurrence of the event.

e. Any other matter involving safe operation of the nuclear power plant which the Manager - Corporate Nuclear Safety and Quality Assurance Audit Section deems appropriate for consideration, or which is referred to the Manager - Corporate Nuclear Safety and Quality Assurance Audit Section by the onsite operating organization or by other fuctional organizational units within Carolina Power and Light Company.

f. Reports and meeting minutes of the PNSC.

FOLLOW-UP ACTION

6.5.3.4 Results of Corporate Nuclear Safety (CNS) reviews, including recommendations and concerns shall be documented.

a. Copies of the documented review shall be retained in the Corporate Nuclear Safety and Quality Assurance Audit Section files.

b. Recommendations and concerns shall be submitted to the Vice President - Nuclear Operations within 14 days of determination.

c. A summation of Corporate Nuclear Safety recommendations and concerns shall be submitted to the Chairman/Chief Executive Officer; Senior Executive Vice President and Chief Operating Officer; Executive Vice President - Power Supply and Customer Services; Senior Vice President - Power Supply; Vice President-Nuclear Safety and Research; Plant General Manager; and others, as appropriate on at least a bi-monthly frequency.

6.5.3.5 The Corporate Nuclear Safety Unit review program shall be conducted in accordance with written, approved procedures.

6.5.4 OPERATION AND MAINTENANCE UNIT (OMU)

FUNCTION

6.5.4.1 The Operation and Maintenance Unit of the Corporate Nuclear Safety and Quality Assurance Audit Section shall perform audits of plant activities. These audits shall encompass:

a. The conformance of facility operation to all provisions contained within the Technical Specifications and applicable license conditions at least once per 12 months.

b. The training and qualifications of the entire facility staff at least once per 12 months.

c. The results of actions taken to correct deficiencies occurring in facility equipment, structures, systems, or method of operation that affect nuclear safety at least once per 6 months.

d. The verification of compliance and implementation of the requirements of the Quality Assurance Program to meet the criteria of Appendix "B", 10 CFR 50, at least once per 24 months.

e. The Emergency Plan and implementing procedures at least once per 24 months.

f. The Security Plan and implementing procedures at least once per 24 months.

g. The Facility Fire Protection Program and implementing procedures at least once per 24 months.

h. Any other area of facility operation considered appropriate by the Corporate Quality Assurance Audit Operation and Maintenance Unit, the Executive Vice President - Power Supply and Customer Service, or the Senior Vice President - Power Supply.

PERSONNEL

6.5.4.2

a. Audit personnel shall be independent of the area audited. Selection for auditing assignments is based on experience or training which establishes that their qualifications are commensurate with the complexity or special nature of the activities to be audited. In selecting auditing personnel, consideration shall be given to special abilities, specialized technical training, prior pertinent experience, personal characteristics, and education.

b. Qualified outside consultants or other individuals independent from those personnel directly involved in plant operation, but within the Operations Group, shall be used to augment the audit teams when necessary.

REPORTS

6.5.4.3 Results of audit are approved by the Manager - Corporate Nuclear Safety and Quality Assurance Audit Section and transmitted directly to the Company President/Chief Executive Officer, the Senior Executive Vice President and Chief Operating Officer, the Executive Vice President - Power Supply and Customer Services, the Senior Vice President - Power Supply, and the Vice President - Nuclear Safety and Research, and others, as appropriate within 30 days after the completion of the audit.

6.5.4.4 The Corporate Quality Assurance Audit Program shall be conducted in accordance with written, approved procedures.

6.5.5 OUTSIDE AGENCY INSPECTION AND AUDIT PROGRAM

6.5.5.1 An independent fire protection and loss prevention program inspection and audit shall be performed at least once per 12 months utilizing an outside fire protection firm.

6.5.5.2 An inspection and audit of the fire protection and loss prevention program shall be performed by a qualified outside fire consultant at least once per 36 months.

6.6 REPORTABLE OCCURRENCE ACTION

6.6.1 The following actions shall be taken for REPORTABLE OCCURRENCES:

a. The Commission shall be notified and/or a report submitted pursuant to the requirements of Specification 6.9.

b. Each REPORTABLE OCCURRENCE requiring 24 hour notification to the Commission shall be reviewed by the PNSC and submitted to Manager - Corporate Nuclear Safety and Quality Assurance Audit and the Vice President - Nuclear Operations.

6.7 SAFETY LIMIT VIOLATION

6.7.1 The following actions shall be taken in the event a Safety Limit is violated:

a. The facility shall be placed in at least HOT SHUTDOWN within two hours.

b. The Safety Limit violation shall be reported to the Commission, the Vice President - Nuclear Operations and to the Manager - Corporate Nuclear Safety and Quality Assurance Audit within 24 hours.

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

d. The Safety Limit Violation Report shall be submitted to the Commission, the Manager - Corporate Nuclear Safety and Quality Assurance Audit and the Vice President - Nuclear Operations within 14 days of the violation.

6.8 PROCEDURES

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

a. The applicable procedures recommended in Appendix "A" of Regulatory Guide 1.33, November, 1972.

b. Refueling operations.

c. Surveillance and test activities of safety related equipment.

d. Security Plan implementation.

e. Emergency Plan implementation.

f. Fire Protection Program implementation.

PROCEDURES (Continued)

6.8.2 Each procedure of 6.8.1 above, and changes thereto, shall be reviewed by the PNSC and approved by the General Manager prior to implementation and reviewed periodically by the PNSC as set forth in administrative procedures.

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

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

b. The change is approved by two members of the plant management staff, at least one of whom holds a Senior Reactor Operator's License on the Brunswick Plant.

c. The change is documented, reviewed by the PNSC and approved by the General Manager within 14 days of implementation.

6.9 REPORTING REQUIREMENTS

ROUTINE REPORTS AND REPORTABLE OCCURRENCES

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

STARTUP REPORT

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

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

6.1.1.3 Startup reports shall be submitted within (1) 90 days following completion of the startup test program, (2) 90 days following resumption or commencement of commercial power operation, or (3) 9 months following initial criticality, whichever is earliest. If the Startup Report does not cover all three events (i.e., initial criticality, STARTUP REPORT (Continued)

completion of startup test program, and resumption or commencement of commercial power operation), supplementary reports shall be submitted at least every three months until all three events have been completed.

ANNUAL REPORTS[1]

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

6.9.1.5 Reports required on an annual basis shall include a tabulation of the number of station, utility and other personnel (including contractors) receiving exposures greater than 100 mrem/yr and their associated man rem exposure according to work and job functions,[2] e.g., reactor operations and surveillance, inservice inspection, routine maintenance, special maintenance (describe maintenance), waste processing, and refueling. The dose assignment to various duty functions may be estimates based on pocket dosimeter, TLD, or film badge measurements. Small exposures totalling less than 20% of the individual total dose need not be accounted for. In the aggregate, at least 80% of the total whole body dose received from external sources shall be assigned to specific major work functions.

MONTHLY OPERATING REPORT

6.9.1.6 Routine reports of operating statistics and shutdown experience shall be submitted on a monthly basis to the Office of Inspection and Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555, with a copy to the Regional Office, to arrive no later than the tenth of each month following the calendar month covered by the report.

REPORTABLE OCCURRENCES

6.9.1.7 The REPORTABLE OCCURRENCES of Specifications 6.9.1.8 and 6.9.1.9 below, including corrective actions and measures to prevent recurrence, shall be reported to the NRC. Supplemental reports may be required to fully describe final resolution of occurrence. In case of corrected or supplemental reports, a licensee event report shall be completed and reference shall be made to the original report date.

1/ A single submittal may be made for a multiple unit station. The submittal should combine those sections that are common to all units at the station.

2/ This tabulation supplements the requirements of §20.407 of 10 CFR Part 20.

SPECIAL REPORTS

6.9.2 Special reports shall be submitted to the Director of the Office of Inspection and Enforcement Regional Office within the time period specified for each report. These reports shall be submitted covering the activities identified below pursuant to the requirements of the applicable reference specification:

a. Inoperable Seismic Monitoring Instrumentation, Specification 3.3.5.1.

b. Seismic event analysis, Specification 4.3.5.1.2.

c. Reactor coolant specific activity analysis, Specification 3.4.5.

d. Fire detection instrumentation, Specification 3.3.5.7.

e. Fire suppression systems, Specifications 3.7.7.1, 3.7.7.2, and 3.7.7.3.

f. ECCS actuation, Specifications 3.5.3.1 and 3.5.3.2.

6.10 RECORD RETENTION

Facility records shall be retained in accordance with ANSI-N45.2.9-1974.

6.10.1 The following records shall be retained for at least five years:

a. Records and logs of facility operation covering time interval at each power level.

b. Records and logs of principal maintenance activities, inspections, repair and replacement of principal items of equipment related to nuclear safety.

c. All REPORTABLE OCCURRENCE submitted to the Commission.

d. Records of surveillance activities, inspections and calibrations required by these Technical Specifications.

e. Records of changes made to Operating Procedures.

f. Records of radioactive shipments.

g. Records of sealed source and fission detectors leak tests and results.

h. Records of annual physical inventory of all sealed source material of record.

RECORD RETENTION (Continued)

6.10.2 The following records shall be retained for the duration of the Facility Operating License:

a. Records and drawing changes reflecting facility design modifications made to systems and equipment described in the Final Safety Analysis Report.

b. Records of new and irradiated fuel inventory, fuel transfers and assembly burnup histories.

c. Records of facility radiation and contamination surveys.

d. Records or radiation exposure for all individuals entering radiation control areas.

e. Records of gaseous and liquid radioactive material released to the environs.

f. Records of transient or operational cycles for those facility components identified in Table 5.7.1-1.

g. Records of reactor tests and experiments.

h. Records of training and qualification for current members of the plant staff.

i. Records of in-service inspections performed pursuant to these Technical Specifications.

j. Records of Quality Assurance activities required by the QA Manual.

k. Records of reviews performed for changes made to procedures or equipment or reviews of tests and experiments pursuant to 10 CFR 50.59.

l. Records of meetings of the PNSC and of the previous off-site review organization, the Company Nuclear Safety Committee (CNSC).

6.11 RADIATION PROTECTION PROGRAM

Procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR Part 20 and shall be approved, maintained and adhered to for all operations involving personnel radiation exposure.

Objective

This section describes the administrative controls and procedures necessary to implement the Environmental Technical Specifications.

5.1 ORGANIZATION AND REVIEW

The Plant Manager is directly responsible for the safe operation of the facility as shown in Figure 5.1-1. In all matters pertaining to the operation of the plant and to the Environmental Technical Specifications, the Plant Manager is directly responsible to the Manager of Nuclear Generation. The Environmental and Radiation Control Supervisor is directly responsible to the Plant Manager for all Environmental Technical Specifications applicable to the plant, radiological and otherwise. In the Generation Department, the Manager - Generation Services, Harris Energy & Environmental Center Section, and his staff function in a staff capacity to assist in the proper implementation of the Environmental Technical Specifications.

Review of plant operations and the technical specifications shall be accomplished by the Plant Nuclear Safety Committee (PNSC) and the Corporate Nuclear Safety (CNS) Unit as organizationally described in Appendix A to the facility operating license. Independent off-site QA audits of plant operations shall be performed by the Operation & Maintenance (O&M) Unit as described in Appendix A to the facility operating license.

Review and audit functions are defined as follows:

a. Review by PNSC and CNS of proposed changes to the Environmental Technical Specifications and the evaluated impact of the change.

b. Review by PNSC and CNS of changes or modifications to plant systems or equipment which are determined by the Plant Manager to have a significant adverse effect on the environment and the evaluated impact of the change.

c. Review by PNSC and CNS of written procedures and changes thereto as described in Section 5.3.2 which are determined by the Plant Manager to detrimentally affect the plant's environmental impact.

d. Investigation by the PNSC of reported instances where an environmental protection limit is exceeded or the occurrence of an unusual environmental event associated with operation of the plant which involves a significant environmental impact. The report and recommendations that result from the PNSC investigation will be reviewed by the CNS.

e. Corporate quality assurance audit of plant operations and written procedures for implementation of these Technical Specifications by O&M.

5.2 ACTION TO BE TAKEN IN THE EVENT OF AN ENVIRONMENTAL EVENT DURING PLANT OPERATIONS

5.2.1 An environmental event shall be reported promptly to the Manager of Nuclear Generation and reviewed by the Plant Nuclear Safety Committee. The Plant Manager shall take action to abate any impact, immediately following his determination of appropriate action permitted by the technical specifications.

5.2.2 As specified in Section 5.4.2, a report of each environmental event shall be reviewed by the Plant Nuclear Safety Committee. This report shall include an evaluation of the cause of the event, a record of the corrective action taken, and the recommendations for appropriate action to prevent or reduce the probability of a recurrence.

5.2.3 Copies of [illegible]ll such reports shall be subm[illegible]ed to the Manager of Nuclear Generation and the Manager of Corporate Nuclear Safety and Quality Assurance Audit Section for review.

5.2.4 The circumstances of any environmental event shall be reported to the NRC as specified in Section 5.4.2.

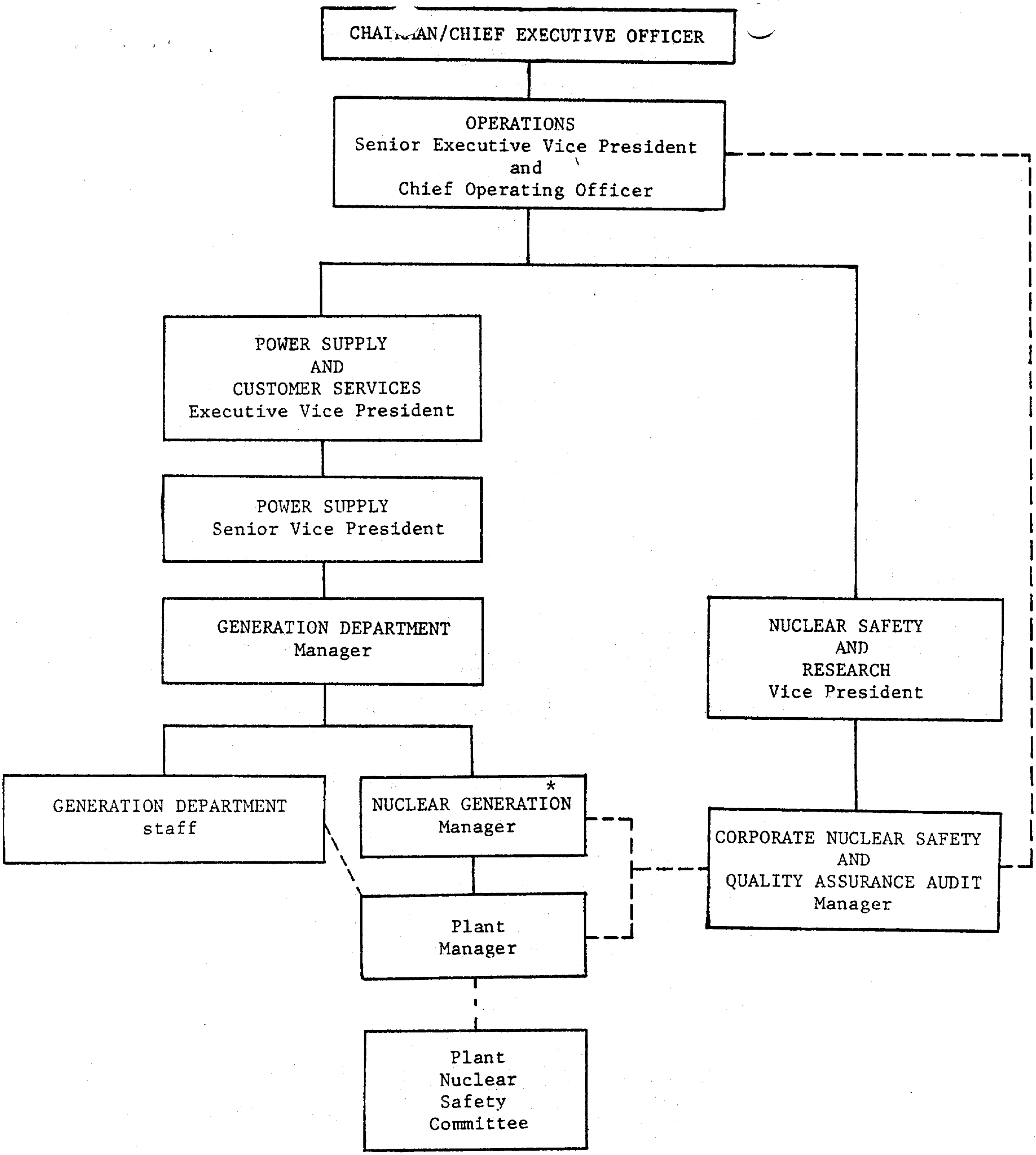
5.3 OPERATING PROCEDURES

5.3.1 Written procedures shall be prepared and approved as specified in Section 5.3.2 for operation to ensure compliance with the environmental protection conditions and associated surveillance requirements of Sections 2 and 3. Procedures will include sampling, analysis, and actions to be taken when environmental protection conditions are exceeded. Quality assurance procedures will be developed for monitoring, sample collection, and sample analysis. Testing frequency of any alarms will also be included.

5.3.2 Procedures described in Section 5.3.1 above, and changes thereto, determined by the Plant Manager to detrimentally affect the plant's environmental impact, shall be reviewed as specified in Section 5.1 and approved by the Plant Manager prior to implementation. Temporary changes to procedures which do not change the intent of the original procedure may be made, provided such changes are approved by two members of the plant management staff. Such changes shall be documented, and subsequently reviewed by the Plant Nuclear Safety Committee and approved by the Plant Manager prior to implementation as permanent procedure changes.

5.3.3 Procedures described in Section 5.3.1 above, and changes thereto, which are determined by the Plant Manager to not detrimentally affect the plant's environmental impact shall be reviewed and approved by the Plant Manager or other member of the plant management staff designated by the Plant Manager prior to implementation.

5.3.4 Written procedures shall be prepared and approved



*Responsible for performance and monitoring of Fire Protection Program.

MANAGEMENT ORGANIZATION CHART
Figure 5.1-1

Analyses of environmental samples which exceed the larger of either the control station value (Table 4.2-5) or the minimum detection limit by a factor of 10 or more for that same sample type and time period will be identified and if determined to be attributable to the operation of the Brunswick Plant, a written report shall be submitted to Director of the appropriate regional office (copy to the Director of Nuclear Reactor Regulation) within 30 days after confirmation.* The test for exceeding the guide value will be a T test at 99.5% confidence. The test will be considered positive when:

$$X_i - (X_c\ 10) > T_{99.5\%} \sqrt{\sigma_i^2 + \sigma_c^2\ (100)}$$

where:

$T_{99.5\%}$ = 1 tail T test (2.2414)

X_i = value obtained at station i

X_c = either value obtained at control station or minimum detection limit (mdl), whichever is larger.

σ_i = standard deviation of station i value

σ_c = standard deviation of control station

*A confirmatory reanalysis of the original, a duplicate or a new sample may be desirable, as appropriate. The results of the confirmatory analysis shall be completed at the earliest time consistent with the analysis, but in any case within 30 days. If the high value is real, the report to the NRC shall be submitted.

If milk samples collected over a calendar quarter show average I-131 concentrations of 4.8 picocuries per liter or greater and the increase is determined to be attributable to the operation of the Brunswick Plant, a written report shall be submitted to the Director of the appropriate regional office (copy to the Director of Nuclear Reactor Regulation) within 30 days, and should include an evaluation of any release conditions, environmental factors, or other aspects necessary to explain the anomalous results.

c. <u>Miscellaneous Reports</u>

(1) When a change to the plant design, to the plant operation, or to the procedures described in Section 5.3 is planned which would have a significant adverse effect on the environment as determined by the Plant Manager or which involves a significant environmental matter or question not previously reviewed and evaluated by the NRC, a report on the change shall be submitted to the NRC for information prior to implementation. The report shall include description and evaluation of the impact of the change.

(2) Request for changes in Environmental Technical Specifications shall be submitted to the Director of Nuclear Reactor Regulation, NRC, for prior review and authorization. The request shall include an evaluation of the impact of the change.

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

CAROLINA POWER & LIGHT COMPANY

DOCKET NO. 50-324

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NO. 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 51
License No. DPR-62

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

   A. The applications for amendment by Carolina Power & Light Company dated October 25, December 27, 1976; July 28, 1977; January 18, February 2, March 6, March 21, April 13, April 27, May 1, May 29, October 8, November 7, December 31, 1979; February 5, February 20, April 1, April 11, and April 22, May 21, and May 27 1980, comply with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

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

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

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

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

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment and paragraqph 2.C.(2) of Facility Operating License No. DPR-62 is hereby amended to read as follows:

   (2) Technical Specifications

   The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 51 are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

for Thomas A. Ippolito, Chief
Operating Reactors Branch #2
Division of Licensing

Attachment:
Changes to the Technical
Specifications

Date of Issuance: June 11, 1980

ATTACHMENT TO LICENSE AMENDMENT NO. 51

FACILITY OPERATING LICENSE NO. DPR-62

DOCKET NO. 50-324

Remove	Insert
I/II	I/II
III/IV	III/IV
V/VI	V/VI
VII/VIII	VII/VIII
IX/X	IX/X
XI/XII	XI/XII
XIII/XIV	XIII/XIV
XV	XV
1-1/2	1-1/2
1-3/4	1-3/4
1-5/6	1-5/6
3/4 0-1/2	3/4 0-1/2
3/4 2-1/2	3/4 2-1/2
3/4 2-9/10	3/4 2-9/10
3/4 2-11/12	3/4 2-11/12
3/4 2-13	3/4 2-13/14
--------	3/4 2-15
3/4 3-1/2	3/4 3-1/2
3/4 3-3/4	3/4 3-3/4
3/4 3-5/6	3/4 3-5/6
3/4 3-9/10	3/4 3-9/10
3/4 3-15/16	3/4 3-15/16
3/4 3-29/30	3/4 3-29/30
3/4 3-31/32	3/4 3-31/32
3/4 3-33/34	3/4 3-33/34
3/4 3-35/36	3/4 3-35/35a
---------	3/4 3-36
---------	3/4 3-38a
3/4 3-61/62	3/4 3-61/62
3/4 3-65/66	3/4 3-65/66
---------	3/4 3-67/68
---------	3/4 3-69/70
---------	3/4 3-71
3/4 7-1/2	3/4 7-1/2
3/4 7-21/22	3/4 7-21/22
3/4 7-51	3/4 7-51
B3/4 0-1/2	B3/4 0-1/2
B3/4 2-1/2	B3/4 2-1/2
B3/4 2-3/4	B3/4 2-3/4
B3/4 3-3/4	B3/4 3-3/4
----------	B3/4 3-5
B3/4 7-3/4	B3/4 7-3/4

Remove	Insert
6-1/2	6-1/2
6-3/4	6-3/4
6-5/6	6-5/6
6-7/8	6-7/8
6-9/10	6-9/10
6-11/12	6-11/12
6-13/14	6-13/14
6-15/16	6-15/16
6-19/20	6-19/20
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ADMINISTRATIVE CONTROLS

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

ACTION

ACTIONS are those additional requirements specified as corollary statements to each specification and shall be part of the specifications.

AVERAGE PLANAR EXPOSURE

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

AVERAGE PLANAR LINEAR HEAT GENERATION RATE

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

CHANNEL CALIBRATION

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

CHANNEL CHECK

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

CHANNEL FUNCTIONAL TEST

A CHANNEL FUNCTIONAL TEST shall be:

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

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

CORE ALTERATION

CORE ALTERATION shall be the addition, removal relocation or movement of fuel, sources, incore instruments or reactivity controls in the reactor core with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATIONS shall not preclude completion of the movement of a component to a safe conservative location.

CRITICAL POWER RATIO

The CRITICAL POWER RATIO (CPR) shall be ratio of that power in the assembly which is calculated, by application of the GEXL correlation, to cause some point in the assembly to experience boiling transition, divided by the actual assembly operating power.

DOSE EQUIVALENT I-131

DOSE EQUIVALENT I-131 shall be concentration of I-131, μCi/gram, which alone would produce the same thyroid dose as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. The following is defined equivalent to 1μCi of I-131: I-132, 29μCi; I-133, 3.6μCi; I-134, insignificant; I-135, 12μCi.

$\overline{E}$-AVERAGE DISINTEGRATION ENERGY

$\overline{E}$ shall be the average, weighted in proportion to the concentration of each radionuclide in the reactor coolant at the time of sampling, of the sum of the average beta and gamma energies per disintegration (in MeV) for isotopes with half lives greater than 15 minutes making up at least 95% of the total non-iodine activity in the coolant.

EMERGENCY CORE COOLING SYSTEM (ECCS) RESPONSE TIME

The EMERGENCY CORE COOLING SYSTEM (ECCS) RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ECCS actuation setpoint at the channel sensor until the ECCS equipment is capable of performing its safety function (i.e., the valves travel to their required positions, pump discharge pressure reach their required values, etc.). Times shall include diesel generator starting and sequence loading delays where applicable.

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME

The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be that time interval to recirculation pump breaker trip from initial movement of the associated:

a. Turbine stop valves, and

b. Turbine control valves.

FREQUENCY NOTATION

The FREQUENCY NOTATION specified for the performance of Surveillance Requirements shall correspond to the intervals defined in Table 1.1.

IDENTIFIED LEAKAGE

IDENTIFIED LEAKAGE shall be:

a. Leakage into collection systems, such as pump seal or valve packing leaks that is captured and conducted to a sump or collecting tank, or

b. Leakage into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of the leakage detection systems or not be PRESSURE BOUNDARY LEAKAGE.

ISOLATION SYSTEM RESPONSE TIME

The ISOLATION SYSTEM RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its isolation actuation setpoint at the channel sensor until the isolation valves travel to their required positions. Times shall include diesel generator starting and sequence loading delays where applicable.

LIMITING CONTROL ROD PATTERN

A LIMITING CONTROL ROD PATTERN shall be a pattern which results in the core being on a thermal hydraulic limit, i.e., operating on a limiting value for APLHGR, LHGR, or MCPR.

LINEAR HEAT GENERATION RATE

LINEAR HEAT GENERATION RATE (LHGR) shall be the power generation in an arbitrary length of fuel rod, usually one foot. It is the integral of the heat flux over the heat transfer area associated with the unit length, usually measured in KW/ft.

LOGIC SYSTEM FUNCTIONAL TEST

A LOGIC SYSTEM FUNCTIONAL TEST shall be a test of all relays and contacts of a logic circuit, from sensor output to activated device, to ensure that components are OPERABLE.

MAXIMUM TOTAL PEAKING FACTOR

The MAXIMUM TOTAL PEAKING FACTOR (MTPF) shall be the largest TPF which exists in the core for a given class of fuel for a given operating condition.

MINIMUM CRITICAL POWER RATIO

The MINIMUM CRITICAL POWER RATIO (MCPR) shall be the smallest CPR which exists in the core.

OPERABLE - OPERABILITY

A system, subsystem, train, component or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified function(s). Implicit in this definition shall be the assumption that all necessary attendant instrumentation, controls, normal and emergency electric power sources, cooling or seal water, lubrication or other auxiliary equipment that are required for the system, subsystem, train, component or device to perform its function(s) are also capable of performing their related support function(s).

OPERATIONAL CONDITION

An OPERATIONAL CONDITION shall be any one inclusive combination of mode switch position and average reactor coolant temperature as indicated in Table 1.2.

PHYSICS TESTS

PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation and are 1) described in Section 13 of the FSAR, 2) authorized under the provisions of 10 CFR 50.59, or 3) otherwise approved by the Commission.

PRESSURE BOUNDARY LEAKAGE

PRESSURE BOUNDARY LEAKAGE shall be leakage through a non-isolatable fault in a reactor coolant system component body, pipe wall or vessel wall.

PRIMARY CONTAINMENT INTEGRITY

PRIMARY CONTAINMENT INTEGRITY shall exist when:

a. All penetrations required to be closed during accident conditions are either:

   1. Capable of being closed by an OPERABLE containment automatic isolation valve system, or

   2. Closed by at least one manual valve, blind flange, or deactivated automatic valve secured in its closed position, except as provided in Table 3.6.3-1 of Specification 3.6.3.1, or

PRIMARY CONTAINMENT INTEGRITY (Continued)

b. All equipment hatches are closed and sealed.

c. Each containment air lock is OPERABLE pursuant to Specification 3.6.1.3.

d. The containment leakage rates are within the limits of Specification 3.6.1.2.

e. The sealing mechanism associated with each penetration (e.g., welds, bellows or O-rings) is OPERABLE.

RATED THERMAL POWER

RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 2436 MWT.

REACTOR PROTECTION SYSTEM RESPONSE TIME

REACTOR PROTECTION SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until de-energization of the scram pilot valve solenoids.

REPORTABLE OCCURRENCE

A REPORTABLE OCCURRENCE shall be any of those conditions specified in Specifications 6.9.1.8 and 6.9.1.9.

ROD DENSITY

ROD DENSITY shall be the number of control rod notches inserted as a fraction of the total number of notches. All rods fully inserted are equivalent to 100% ROD DENSITY.

SECONDARY CONTAINMENT INTEGRITY

SECONDARY CONTAINMENT INTEGRITY shall exist when:

a. All automatic Reactor Building ventilation system isolation valves or dampers are OPERABLE or secured in the isolated position,

b. The standby gas treatment system is OPERABLE pursuant to Specification 3.6.6.1.

c. At least one door in each access to the Reactor Building is closed.

d. The sealing mechanism associated with each penetration (e.g., welds, bellows or O-rings) is OPERABLE.

SHUTDOWN MARGIN

SHUTDOWN MARGIN shall be the amount of reactivity by which the reactor would be subcritical assuming that all control rods capable of insertion are fully inserted except for the analytically determined highest worth rod which is assumed to be fully withdrawn, and the reactor is in the shutdown condition, cold, 68°F, and Xenon free.

STAGGERED TEST BASIS

A STAGGERED TEST BASIS shall consist of:

a. A test schedule for n systems, subsystems, trains or other designated components obtained by dividing the specified test interval into n equal subintervals.

b. The testing of one system, subsystem, train or other designated component at the beginning of each subinterval.

THERMAL POWER

THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

TOTAL PEAKING FACTOR

The TOTAL PEAKING FACTOR (TPF) shall be the ratio of local LHGR for any specific location on a fuel rod divided by the average LHGR associated with the fuel bundles of the same type operating at the core average bundle power.

UNIDENTIFIED LEAKAGE

UNIDENTIFIED LEAKAGE shall be all leakage which is not IDENTIFIED LEAKAGE.

3/4.0 APPLICABILITY

LIMITING CONDITION FOR OPERATION

3.0.1 Limiting Conditions for Operation and ACTION requirements shall be applicable during the OPERATIONAL CONDITIONS or other states specified for each specification.

3.0.2 Adherence to the requirements of the Limiting Condition for Operation and associated ACTION within the specified time interval shall constitute compliance with the specification. In the event the Limiting Condition for Operation is restored prior to expiration of the specified time interval, completion of the ACTION statement is not required.

3.0.3 In the event a Limiting Condition for Operation and/or associated ACTION requirements cannot be satisfied because of circumstances in excess of those addressed in the specification, the facility shall be placed in at least HOT SHUTDOWN within 6 hours and in COLD SHUTDOWN within the following 30 hours unless corrective measures are completed that permit operation under the permissible ACTION statements for the specified time interval as measured from initial discovery or until the reactor is placed in an OPERATIONAL CONDITION in which the specification is not applicable. Exceptions to these requirements shall be stated in the individual specifications.

3.0.4 Entry into an OPERATIONAL CONDITION or other specified applicability state shall not be made unless the conditions of the Limiting Condition for Operation are met without reliance on provisions contained in the ACTION statements unless otherwise excepted. This provision shall not prevent passage thru OPERATIONAL CONDITIONS required to comply with ACTION requirements.

SURVEILLANCE REQUIREMENTS

4.0.1 Surveillance Requirements shall be applicable during the OPERATIONAL CONDITIONS or other states specified for individual Limiting Conditions for Operation unless otherwise stated in an individual Surveillance Requirement.

4.0.2 Each Surveillance Requirement shall be performed within the specified time interval with:

a. A maximum allowable extension not to exceed 25% of the surveillance interval, SURVEILLANCE REQUIREMENTS (Continued)

b. A total maximum combined interval time for any 3 consecutive surveillance intervals not to exceed 3.25 times the specified surveillance interval.

4.0.3 Performance of a Surveillance Requirement within the specified time interval shall constitute compliance with OPERABILITY requirements for a Limiting Condition for Operation and associated ACTION statements unless otherwise required by the specification. Surveillance requirements do not have to be performed on inoperable equipment.

4.0.4 Entry into an OPERATIONAL CONDITION or other specified applicable state shall not be made unless the Surveillance Requirement(s) associated with the Limiting Condition for Operation have been performed within th applicable surveillance interval or as otherwise specified.

4.0.5 Surveillance Requirements for inservice inspection and testing of ASME Code Class 1, 2 & 3 components shall be applicable as follows:

a. During the time period:

1. From issuance of the Facility Operating License to the start of facility commercial operation, inservice testing of ASME Code Class 1, 2 & 3 pumps and valves shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code 1974 Edition, and Addenda through Winter 1975 except where specific written relief has been granted by the Commission.

2. Following start of facility commercial operation, inservice inspection of ASME Code Class 1, 2, and 3 components and inservice testing of ASME Code Class 1, 2, and 3 pumps and valves shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR 50, Section 50.55a(g), except where specific written relief has been granted by the Commission pursuant to 10 CFR 50, Section 50.55a(g) (6) (i).

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 (APLHGR's) for each type of fuel as a function of AVERAGE PLANAR EXPOSURE shall not exceed the limits shown in Figures 3.2.1-1, 3.2.1-2, 3.2.1-3, 3.2.1-4, 3.2.1-5, 3.2.1-6, 3.2.1-7 or 3.2.1-8.

APPLICABILITY: CONDITION 1, when THERMAL POWER $\geq$ 25% of RATED THERMAL POWER.

ACTION:

With an APLHGR exceeding the limits of Figures 3.2.1-1, 3.2.1-2, 3.2.1-3, 3.2.1-4, 3.2.1-5, 3.2.1-6, 3.2.1-7 or 3.2.1-8, initiate corrective action within 15 minutes and continue corrective action so that APLHGR is within the limit within 4 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

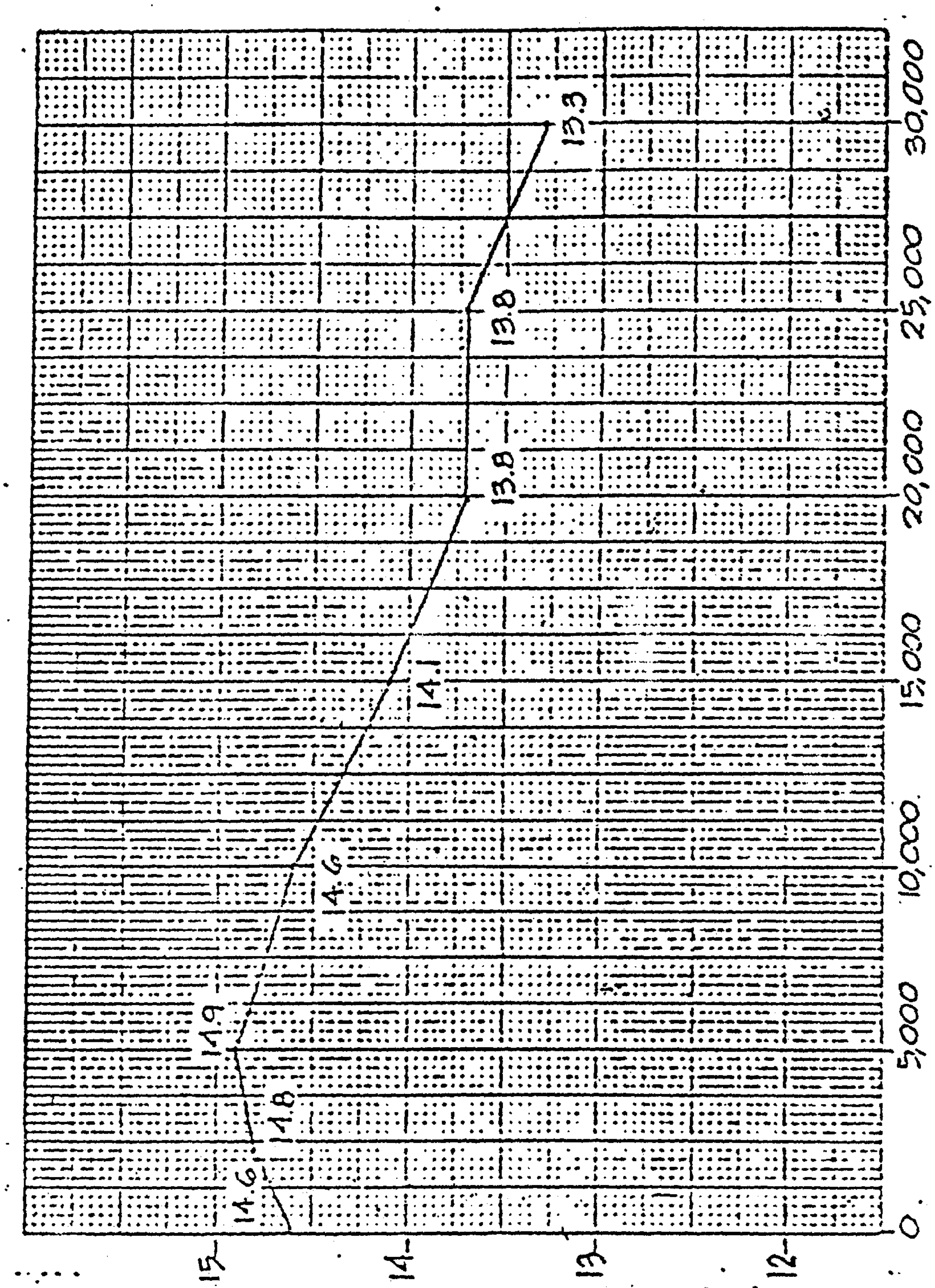
SURVEILLANCE REQUIREMENTS

4.2.1 All APLHGR's shall be verified to be equal to or less than the applicable limit determined from Figures 3.2.1-1, 3.2.1-2, 3.2.1-3, 3.2.1-4, 3.2.1-5, 3.2.1-6, 3.2.1-7 or 3.2.1-8:

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.

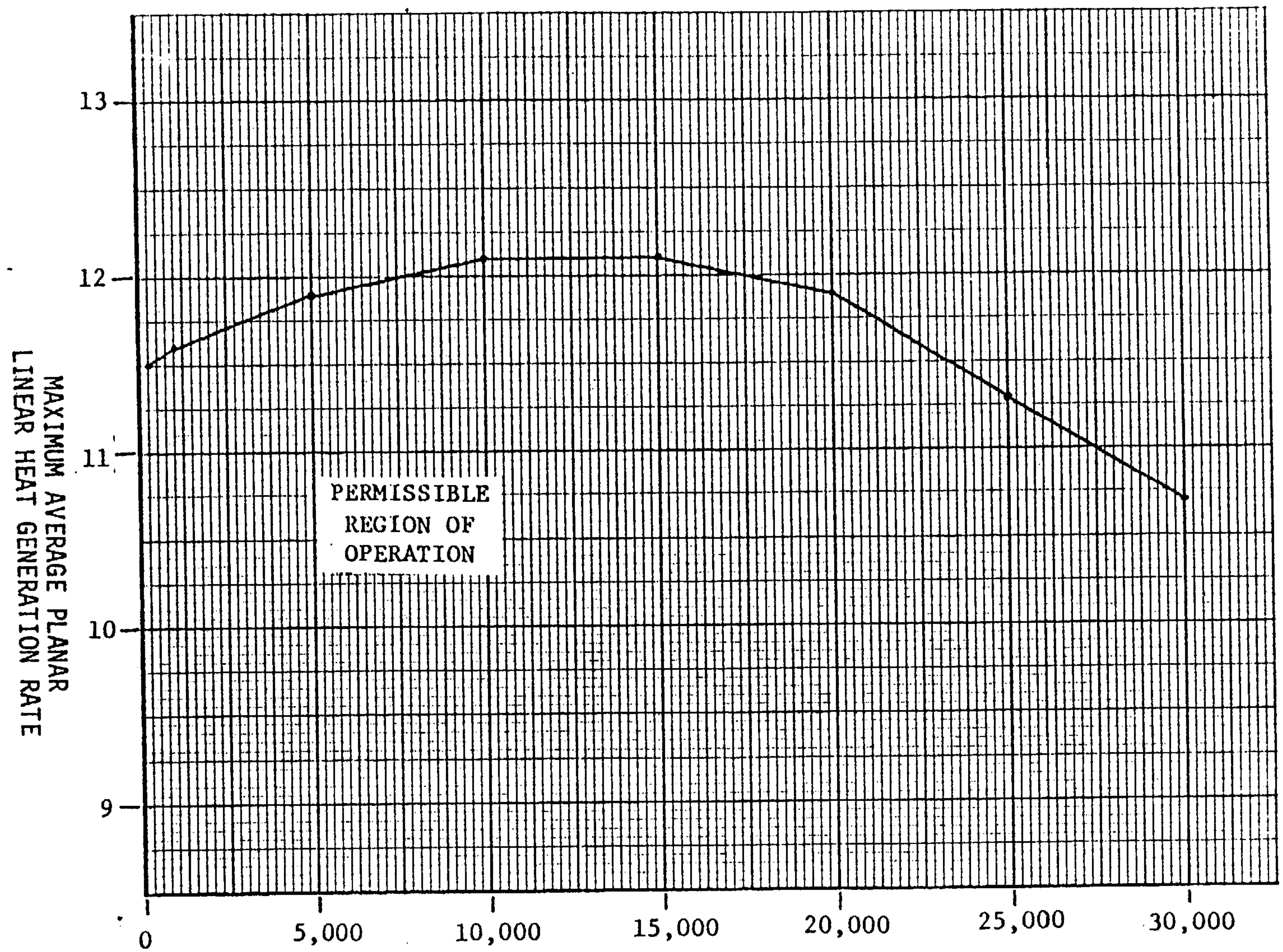


AVERAGE PLANAR EXPOSURE (MWd/t)

MAXIMUM AVERAGE PLANAR
LINEAR HEAT GENERATION RATE

FUEL TYPE 1 & 2 (7x7)
MAXIMUM AVERAGE PLANAR LINEAR HEAT
GENERATION RATE (MAPLHGR)
VERSUS AVERAGE PLANAR EXPOSURE

FIG[illegible] 3.2.1-1



PLANAR AVERAGE EXPOSURE (MWd/t)
FUEL TYPE P8DRB265H
MAXIMUM AVERAGE PLANAR LINEAR HEAT
GENERATION RATE (MAPLHGR)
VERSUS PLANAR AVERAGE EXPOSURE

FIGURE 3.2.1-8

3/4.2.2 APRM SETPOINTS

LIMITING CONDITION FOR OPERATION

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

$$S \leq (0.66W + 54\%)\ T$$

$$S_{RB} \leq (0.66W + 42\%)\ T$$

where: S and S_{RB} are in percent of RATED THERMAL POWER,
W = Loop recirculation flow in percent of rated flow,
T = Lowest value of the ratio of design TPF divided by the MTPF obtained for any class of fuel in the core ($T \leq 1.0$), and

Design TPF for: P8 x 8R fuel = 2.48
8 x 8R fuel = 2.48
7 x 7 fuel = 2.60
8 x 8 fuel = 2.45

APPLICABILITY: CONDITION 1, when THERMAL POWER $\geq$ 25% of RATED THERMAL POWER.

ACTION:

With S or S_{RB} exceeding the allowable value, initiate corrective action within 15 minutes and continue corrective action so that S and S_{RB} are within the required limits within 4 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.2 The MTPF for each class of fuel shall be determined, the value of T calculated, and the flow biased APRM trip setpoint 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 a LIMITING CONTROL ROD PATTERN for MTPF.

3/4.2.3 MINIMUM CRITICAL POWER RATIO

LIMITING CONDITION FOR OPERATION

3.2.3 The MINIMUM CRITICAL POWER RATIO (MCPR), as a function of core flow, shall be equal to or greater than MCPR times the K_f shown in Figure 3.2.3-1, provided that the end-of-cycle recirculation pump trip system is OPERABLE per Specification 3.3.6.2, with:

a. MCPR for 7x7 fuel = 1.21,*
b. MCPR for 8x8 fuel = 1.28,
c. MCPR for 8x8R fuel = 1.27, and
d. MCPR for P8x8R fuel = 1.27.

APPLICABILITY: CONDITION 1, when THERMAL POWER ≥ 25% RATED THERMAL POWER.

ACTION:

a. With the end-of-cycle recirculation pump trip system inoperable per Specification 3.3.6.2, operation may continue and the provisions of Specification 3.0.4 are not applicable with the following MCPR adjustments:

   1. Beginning-of-cycle (BOC) to end-of-cycle (EOC) minus 2000 MWD/t, within one hour determine that MCPR, as a function of core flow, is equal to or greater than MCPR times the K_f shown in Figure 3.2.3-1 with:

      a. MCPR for 7x7 fuel = 1.21,*
      b. MCPR for 8x8 fuel = 1.28,
      c. MCPR for 8x8R fuel = 1.21, and
      d. MCPR for P8x8R fuel = 1.21.

   2. EOC minus 2000 MWD/t to EOC minus 1000 MWD/t, within one hour determine that MCPR, as a function of core flow, is equal to or greater than MCPR times the K_f shown in Figure 3.2.3-1 with:

      a. MCPR for 7x7 fuel = 1.21*
      b. MCPR for 8x8 fuel = 1.28
      c. MCPR for 8x8R fuel = 1.26, and
      d. MCPR for P8x8R fuel = 1.28

   3. EOC minus 1000 MWD/t to EOC, within one hour determine that MCPR, as a function of core flow, is equal to or greater than MCPR times the K_f shown in Figure 3.2.3-1 with:

      a. MCPR for 7x7 fuel = 1.28
      b. MCPR for 8x8 fuel = 1.35
      c. MCPR for 8x8R fuel = 1.34, and
      d. MCPR for P8x8R fuel = 1.36

*For 7x7 fuel assemblies, the K_f factor is based on the 112% flow curve of Figure 3.2.3-1 rather than the actual setpoint of 102.5%.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

b. With MCPR, as a function of core flow, less than the applicable limit determined from Figure 3.2.3-1, initiate corrective action within 15 minutes and restore MCPR to within the applicable limit within 4 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

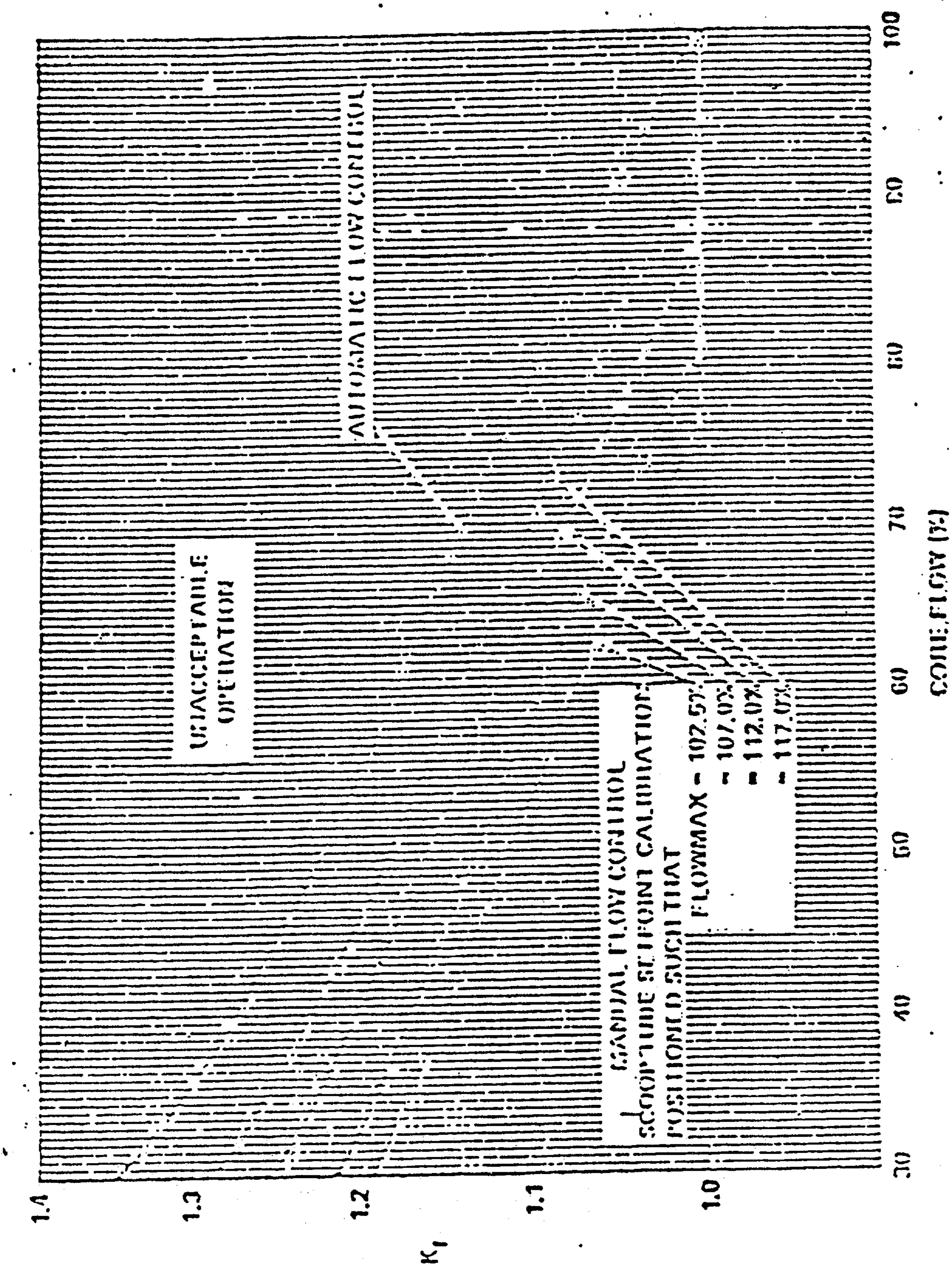
SURVEILLANCE REQUIREMENTS

4.2.3 MCPR, as a function of core flow, shall be determined to be equal to or greater than the applicable limit determined from Figure 3.2.3-1:

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 MCPR.



K_f FACTOR

FIGURE 3.2.3-1

3/4.2.4 LINEAR HEAT GENERATION RATE

LIMITING CONDITION FOR OPERATION

3.2.4 All LINEAR HEAT GENERATION RATES (LHGR's) shall not exceed:

a. For 7 X 7 fuel assemblies, as a function of core height for any fuel rod in an assembly, the maximum allowable LHGR shown in Figure 3.2.4-1.

b. For 8 X 8, 8 X 8R and P8 X 8R fuel assemblies, 13.4 kw/ft.

APPLICABILITY: CONDITION 1, when THERMAL POWER ≥ 25% of RATED THERMAL POWER.

ACTION:

With the LHGR of any fuel rod exceeding the above limits, initiate corrective action within 15 minutes and continue corrective action so that the LHGR is within the limit within 4 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

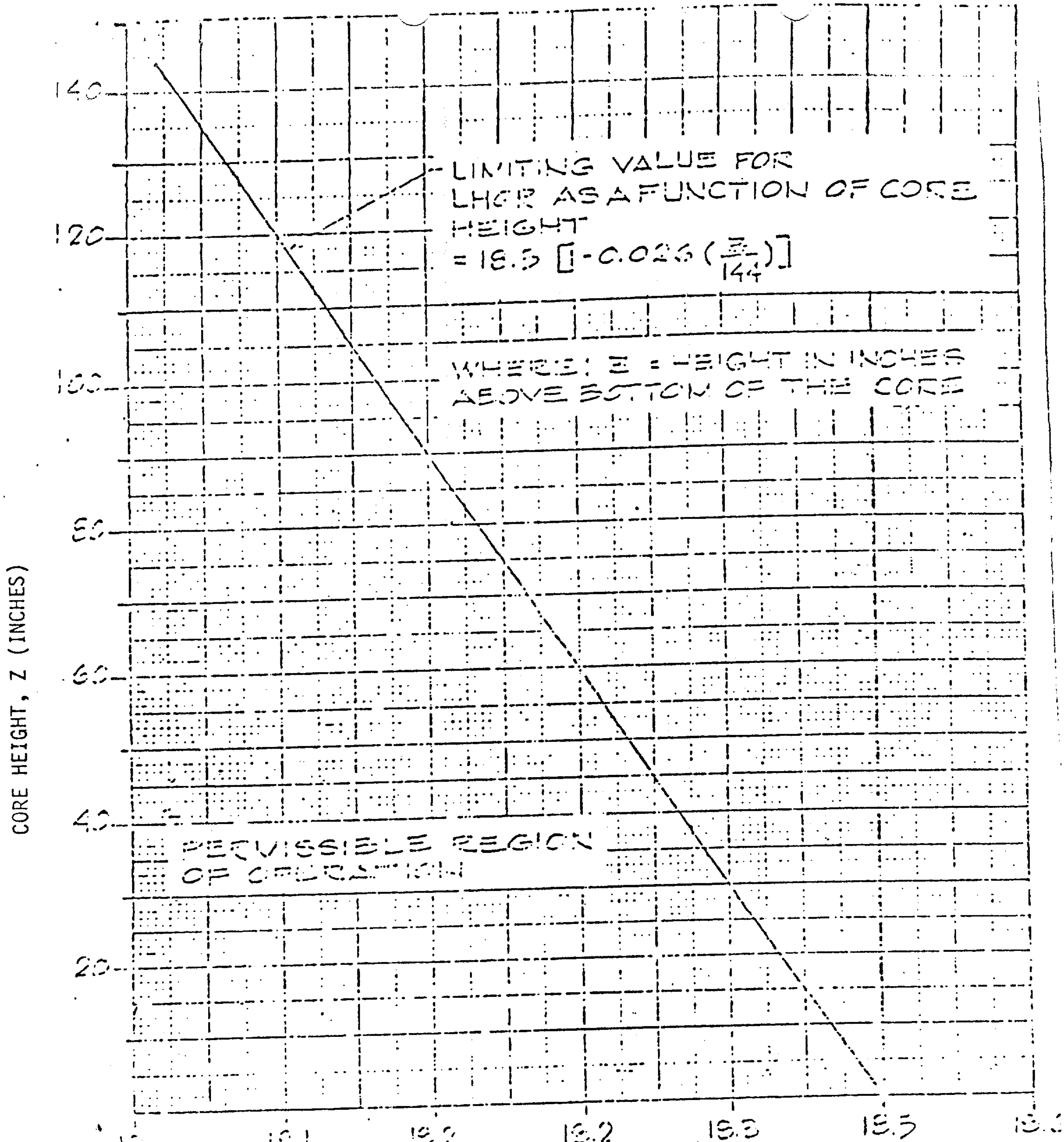
SURVEILLANCE REQUIREMENTS

4.2.4 LHGR's shall be determined to be equal to or less than the applicable above limit:

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 on a LIMITING CONTROL ROD PATTERN for LHGR.



LHGR (kw/ft)
LIMITING VALUE FOR LHGR
7 x 7 FUEL

FIGURE 3.2.4-1

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 REACTOR PROTECTION SYSTEM RESPONSE TIME as shown in Table 3.3.1-2. Set points and interlocks are given in Table 2.2.1-1.

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

a. With the requirements for the minimum number of OPERABLE channels not satisfied for one trip system, place at least one inoperable channel in the tripped condition within one hour.

b. With the requirements for the minimum number of OPERABLE channels not satisfied for both trip systems, place at least one inoperable channel in at least one trip system* in the tripped condition within one hour and take the ACTION required by Table 3.3.1-1.

c. The provisions of Specification 3.0.3 are not applicable in OPERATIONAL CONDITION 5.

SURVEILLANCE REQUIREMENTS

4.3.1.1 Each reactor protection system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations during the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.1-1.

4.3.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed at least once per 18 months and shall include calibration of time delay relays and timers necessary for proper functioning of the trip system.

4.3.1.3 The REACTOR PROTECTION SYSTEM RESPONSE TIME of each reactor trip function of 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 logic train such that both logic trains are tested at least once per 36 months and one channel per function 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 function.

*If both channels are inoperable in one trip system, select at least one inoperable channel in that trip system to place in the tripped condition, except when this could cause the Trip Function to occur.

TABLE 3.3.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT AND INSTRUMENT NUMBER	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM NUMBER OPERABLE CHANNELS PER TRIP SYSTEM (a)	ACTION
1. Intermediate Range Monitors: (C51-IRM-K601 A,B,C,D,E,F,G,H)			
a. Neutron Flux - High	2, 5$^{(b)}$	3	1
	3, 4	2	2
b. Inoperative	2, 5	3	1
	3, 4	2	2
2. Average Power Range Monitor: (C51-APRM-CH.A,B,C,D,E,F)			
a. Neutron Flux - High, 15%	2, 5$^{(b)}$	2	3
b. Flow Biased Neutron Flux - High	1	2	4
c. Fixed Neutron Flux-High, 120%	1	2	4
d. Inoperative	1, 2, 5	2	5
e. Downscale	1	2	4
f. LPRM	1, 2, 5	(c)	NA
3. Reactor Vessel Steam Dome Pressure - High (B21-PS-N023 A,B,C,D)	1, 2$^{(d)}$	2	6
4. Reactor Vessel Water Level - Low, Level #1 (B21-LIS-N017 A,B,C,D)	1, 2	2	6
5. Main Steam Line Isolation Valve - Closure (B21-F022 A,B,C,D and B21-F028 A,B,C,D)	1	4	4
6. Main Steam Line Radiation - High (D12-RM-K603 A,B,C,D)	1, 2$^{(d)}$	2	7

TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT AND INSTRUMENT NUMBER	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM NUMBER OPERABLE CHANNELS PER TRIP SYSTEM(a)(b)	ACTION
7. Drywell Pressure - High (C72-PS-N002 A,B,C,D)	1, 2(e)	2	6
8. Scram Discharge Volume Water Level - High (C12-LSH-N013 A,B,C,D)	1, 2, 5(f)	2	5
9. Turbine Stop Valve - Closure (EHC-SVOS-1X,2X,3X,4X)	1(g)	4	8
10. Turbine Control Valve Fast Closure, Control Oil Pressure - Low (EHC-PSL-1756,1757,1758,1759)	1(g)	2	8
11. Reactor Mode Switch in Shutdown Position (C72A-S1)	1, 2, 3, 4, 5	1	9
12. Manual Scram (C72A-S3A,B)	1, 2, 3, 4, 5	1	10

TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

ACTION

ACTION 1 - In CONDITION 2, be in at least HOT SHUTDOWN within 6 hours.

In CONDITION 5, suspend all operations involving CORE ALTERATIONS or postive reactivity changes ano fully insert all insertable control rods within one hour.

ACTION 2 - Lock the reactor mode switch in the Shutdown position within one hour.

ACTION 3 - In OPERATIONAL CONDITION 2, be in at least HOT SHUTDOWN within 6 hours.

In OPERATIONAL CONDITION 5, suspend all operations involving CORE ALTERATIONS or positive reactivity changes and fully insert all insertable control rods within one hour.

ACTION 4 - Be in at least STARTUP within 2 hours.

ACTION 5 - In OPERATIONAL CONDITION 1 or 2, be in at least HOT SHUTDOWN within 6 hours.

In OPERATIONAL CONDITION 5, suspend all operations involving CORE ALTERATIONS or positive reactivity changes and fully insert all insertable control rods within one hour.

ACTION 6 - Be in at least HOT SHUTDOWN within 6 hours.

ACTION 7 - Be in STARTUP with the main steam line isolation valves closed within 2 hours or in at least HOT SHUTDOWN within 6 hours.

ACTION 8 - Initiate a reduction in THERMAL POWER within 15 minutes and be at less than 30% of RATED THERMAL POWER within 2 hours.

ACTION 9 - In OPERATIONAL CONDITION 1 or 2, be in at least HOT SHUTDOWN within 6 hours.

In OPERATIONAL CONDITION 3 or 4, immediately and at least once per 12 hours verify that all control rods are fully inserted.

In OPERATIONAL CONDITION 5, suspend all operations involving CORE ALTERATIONS or positive reactivity changes and fully insert all insertable control rods within one hour.

REACTOR PROTECTION SYSTEM INSTRUMENTATION

ACTION 10 - In OPERATIONAL CONDITION 1 or 2, be in at least HOT SHUTDOWN within 6 hours.

In OPERATIONAL CONDITION 3 or 4, lock the reactor mode switch in the Shutdown position within one hour.

In OPERATIONAL CONDITION 5, suspend all operations involving CORE ALTERATIONS or positive reactivity changes and fully insert all insertable control rods within one hour.

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 shutdown margin demonstrations.

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

d. These functions are not required to be OPERABLE when the reactor pressure vessel head is unbolted or removed.

e. This function is not required to be OPERABLE when PRIMARY CONTAINMENT INTEGRITY is not required.

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

g. These functions are bypassed when THERMAL POWER is less than 30% of RATED THERMAL POWER.

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

TABLE 3.3.1-2

REACTOR PROTECTION SYSTEM RESPONSE TIMES

FUNCTIONAL UNIT AND INSTRUMENT NUMBER	RESPONSE TIME (Seconds)
1. Intermediate Range Monitors (C51-IRM-K601 A,B,C,D,E,F,G,H):	
a. Neutron Flux - High*	NA
b. Inoperative	NA
2. Average Power Range Monitor* (C51-APRM-CH.A,B,C,D,E,F):	
a. Neutron Flux - High, 15%	$\leq$ 0.09
b. Flow Biased Neutron Flux - High	NA
c. Neutron Flux - High, 120%	$\leq$ 0.09
d. Inoperative	NA
e. Downscale	NA
f. LPRM	NA
3. Reactor Vessel Steam Dome Pressure - High (B21-PS-N023 A,B,C,D)	$\leq$ 0.55
4. Reactor Vessel Water Level - Level #1 (B21-LIS-N017 A,B,C,D)	$\leq$ 1.05
5. Main Steam Line Isolation Valve-Closure (B21-F022 A,B,C,D and B21-F028 A,B,C,D)	$\leq$ 0.06
6. Main Steam Line Radiation - High (D12-RM-K603 A,B,C,D)	NA
7. Drywell Pressure - High (C72-PS-N002 A,B,C,D)	NA
8. Scram Discharge Volume Water Level - High (C12-LSH-N013 A,B,C,D)	NA
9. Turbine Stop Valve - Closure (EHC-SVOS-1X,2X,3X,4X)	$\leq$ 0.06
10. Turbine Control Valve Fast Closure, Control Oil Pressure - Low (EHC-PSL-1756,1757,1758,1759)	$\leq$ 0.08
11. Reactor Mode Switch in Shutdown Position (C72A-S1)	NA
12. Manual Scram (C72A-S3 A,B)	NA

*Neutron detectors are exempt from response time testing. Response time shall be measured from detector output or input of first electronic component in channel.

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.2 The isolation actuation instrumentation channels shown in Table 3.3.2-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.2-2 and with ISOLATION SYSTEM RESPONSE TIME as shown in Table 3.3.2-3.

APPLICABILITY: As shown in Table 3.3.2-1.

ACTION:

a. With an isolation actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.2-2, declare the channel inoperable and place the inoperable channel in the tripped condition until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. With the requirements for the minimum number of OPERABLE channels not satisfied for one trip system, place at least one inoperable channel in the tripped condition within one hour.

c. With the requirements for the minimum number of OPERABLE channels not satisfied for both trip systems, place at least one inoperable channel in at least one trip system* in the tripped condition within one hour and take the ACTION required by Table 3.3.2-1.

d. The provisions of Specification 3.0.3 are not applicable in OPERATIONAL CONDITION 5.

SURVEILLANCE REQUIREMENTS

4.3.2.1 Each isolation actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations during the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.2-1.

4.3.2.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed at least once per 18 months and shall include calibration of time delay relays and timers necessary for proper functioning of the trip system.

*If both channels are inoperable in one trip system, select at least one inoperable channel in that trip system to place in the tripped condition, except when this would cause the Trip Function to occur.

4.3.2.3 The ISOLATION SYSTEM RESPONSE TIME of each isolation function shown in Table 3.3.2-3 shall be demonstrated to be within its limit at least once per 18 months. Each test shall include at least one logic train such that both logic chains are tested at least once per 36 months and one channel per function 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 isolation function.

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION AND INSTRUMENT NUMBER	VALVE GROUPS OPERATED BY SIGNAL(a)	MINIMUM NUMBER OPERABLE CHANNELS PER TRIP SYSTEM(b)(c)	APPLICABLE OPERATIONAL CONDITION	ACTION
5. SHUTDOWN COOLING SYSTEM ISOLATION				
a. Reactor Vessel Water - Low, Level #1 (B21-LIS-N017A,B,C,D)	2, 6, 7, 8	2	1, 2, 3	27
b. Reactor Steam Dome Pressure-High (B32-PS-N018A,B)	7, 8	1	1, 2, 3	27

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

ACTIONS

ACTION 20 - Be in at least HOT SHUTDOWN within 6 hours and in COLD SHUTDOWN within the following 30 hours.

ACTION 21 - Be in at least STARTUP with the main steam line isolation valves closed within 2 hours or be in at least HOT SHUTDOWN within 6 hours and in COLD SHUTDOWN within the next 30 hours.

ACTION 22 - Be in at least STARTUP within 2 hours.

ACTION 23 - Establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within one hour.

ACTION 24 - Isolate the reactor water cleanup system.

ACTION 25 - Close the affected system isolation valves and declare the affected system inoperable.

ACTION 26 - Verify power availability to the bus at least once per 12 hours.

ACTION 27 - Deactivate the shutdown cooling supply and reactor vessel head spray isolation valves in the closed position until the reactor steam dome pressure is within the specified limits.

NOTES

* When handling irradiated fuel in the secondary containment.

a. See Specification 3.6.3.1, Table 3.6.3.1-1 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. With 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 3.3.2-1 for that Trip Function shall be taken.

d. Trips the mechanical vacuum pumps.

e. A channel is OPERABLE if 2 of 4 instruments in that channel are OPERABLE.

f. With reactor steam pressure $\geq$ 500 psig.

g. Closes only RWCU outlet isolation valve.

h. Alarm only.

TABLE 4.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION AND INSTRUMENT NUMBER	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS IN WHICH SURVEILLANCE REQUIRED
5. SHUTDOWN COOLING SYSTEM ISOLATION				
a. Reactor Vessel Water - Low, Level #1 (B21-LIS-N017A,B,C,D)	D	M	R	1, 2, 3
b. Reactor Steam Dome Pressure - High (B32-PS-N018A,B)	NA	S/U*, M	R	1, 2, 3

*If not performed within the previous 31 days.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3 The Emergency Core Cooling System (ECCS) actuation instrumentation shown in Table 3.3.3-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.3-2 and with EMERGENCY CORE COOLING SYSTEM RESPONSE TIME as shown in Table 3.3.3-3.

APPLICABILITY: As shown in Table 3.3.3-1.

ACTION:

a. With an ECCS actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.3-2, declare the channel inoperable and place the inoperable channel in the tripped condition until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. With one or more ECCS actuation instrumentation channels inoperable, take the ACTION required by Table 3.3.3-1.

c. The provisions of Specification 3.0.3 are not applicable in OPERATIONAL CONDITION 5.

SURVEILLANCE REQUIREMENTS

4.3.3.1 Each ECCS actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations during the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.3-1.

4.3.3.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed at least once per 18 months and shall include calibration of time delay relays and timers necessary for proper functioning of the trip system.

4.3.3.3 The ECCS RESPONSE TIME of each ECCS function shown in Table 3.3.3-3 shall be demonstrated to be within the limit at least once per 18 months. Each test shall include at least one logic train such that both logic trains are tested at least once per 36 months and one channel per function 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 ECCS function.

TABLE 3.3.3-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION AND INSTRUMENT NUMBER	MINIMUM NUMBER OPERABLE CHANNELS PER TRIP SYSTEM	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. CORE SPRAY SYSTEM			
a. Reactor Vessel Water Level - Low, Level #3 (B21-LIS-N031A,B,C,D)	2	1, 2, 3, 4, 5	30
b. Reactor Steam Dome Pressure - Low (Injection Permissive) (B21-PS-N021A,B,C,D)	2	1, 2, 3, 4, 5	31
c. Drywell Pressure - High (E11-PS-N011A,B,C,D)	2	1, 2, 3	30
d. Time Delay Relay	1	1, 2, 3, 4, 5	31
e. Bus Power Monitor# (E21-K1A,B)	1/bus	1, 2, 3, 4, 5	32
2. LPCI MODE OF RHR SYSTEM			
a. Drywell Pressure - High (E11-PS-N011A,B,C,D)	2	1, 2, 3	30
b. Reactor Vessel Water Level - Low, Level #3 (B21-LIS-N031A,B,C,D)	2	1, 2, 3, 4*, 5*	30
c. Reactor Vessel Shroud Level (Drywell Spray Permissive) (B21-LITS-N036 and B21-LITS-N037)	1	1, 2, 3, 4*, 5*	31
d. Reactor Steam Dome Pressure - Low (Injection Permissive) (B21-PS-N021A,B,C,D)			
1. RHR Pump Start and LPCI Injection Valve Actuation	2	1, 2, 3, 4*, 5*	31
2. Recirculation Loop Pump Discharge Valve Actuation	2	1, 2, 3, 4*, 5*	31
e. RHR Pump Start - Time Delay Relay	1	1, 2, 3, 4*, 5*	31
f. Bus Power Monitor# (E11-K106A,B)	1/bus	1, 2, 3, 4*, 5*	32
3. HPCI SYSTEM			
a. Reactor Vessel Water Level - Low, Level #2 (B21-LIS-N031A,B,C,D)	2	1, 2, 3	30
b. Drywell Pressure - High (E11-PS-N011A,B,C,D)	2	1, 2, 3	30
c. Condensate Storage Tank Level-Low (E41-LS-N002, E41-LS-N003)	2**	1, 2, 3	33
d. Suppression Chamber Water Level-High (E41-LSH-N015A,B)	2**	1, 2, 3	33
e. Bus Power Monitor# (E41-K55 and E41-K56)	1/bus	1, 2, 3	32

TABLE 3.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION AND INSTRUMENT NUMBER	MINIMUM NUMBER OPERABLE CHANNELS PER TRIP SYSTEM	APPLICABLE OPERATIONAL CONDITIONS	ACTION
4. ADS			
a. Drywell Pressure - High, coincident with (E11-PS-N010A,B,C,D)	2	1, 2, 3	31
b. Reactor Vessel Water Level - Low, Level #3 (B21-LIS-N031A,B,C,D)	2	1, 2, 3	31
c. ADS Timer (B21-TDPU-K5A,B)	1	1, 2, 3	3
d. Core Spray Pump Discharge Pressure - High (Permissive) (E21-PS-N008A,B and E21-PS-N009A,B)	2	1, 2, 3	3
e. RHR (LPCI MODE) Pump Discharge Pressure - High (Permissive) (E11-PS-N016A,B,C,D and E11-PS-N020A,B,C,D)	2/pump	1, 2, 3	3
f. Bus Power Monitor# (B21-K1A,B)	1/bus	1, 2, 3	32

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE OPERATIONAL CONDITIONS	ACTION
5. LOSS OF POWER					
a. 4.16 kv Emergency Bus Undervoltage (Loss of Voltage)	1/bus	1/bus	1/bus	1, 2, 3, 4##, 5##	34
b. 4.16 kv Emergency Bus Undervoltage (Degraded Voltage)	3/bus	2/bus	2/bus	1, 2, 3, 4##, 5##	35

*Not applicable when two core spray system subsystems are OPERABLE per Specification 3.5.3.1.
**Provides signal to HPCI pump suction valves only.
#Alarm only.
##Required when ESF equipment is required to be OPERABLE.

TABLE 3.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

ACTION

ACTION 30 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement:

a. For one trip system, place at least one inoperable channel in the tripped condition within one hour or declare the associated ECCS inoperable.

b. For both trip systems, declare the associated ECCS inoperable.

ACTION 31 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, declare the associated ECCS inoperable.

ACTION 32 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, verify bus power availability at least once per 12 hours or declare the associated ECCS inoperable.

ACTION 33 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, place at least one inoperable channel in the tripped condition within one hour or declare the HPCS system inoperable.

ACTION 34 - With the number of OPERABLE channels less than the Total Number of Channels, declare the associated emergency diesel generator inoperable and take the ACTION required by Specification 3.8.1.1 or 3.8.1.2, as appropriate.

ACTION 35 - With the number of OPERABLE channels one less than the Total Number of Channels, place the inoperable channel in the tripped condition within 1 hour; operation may then continue until performance of the next required CHANNEL FUNCTIONAL TEST.

TABLE 3.3.3-2

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION AND INSTRUMENT NUMBER	TRIP SETPOINT	ALLOWABLE VALUE
1. CORE SPRAY SYSTEM		
a. Reactor Vessel Water Level - Low, Level #3 (B21-LIS-N031A,B,C,D)	$\geq$ -147.5 inches	$\geq$ -147.5 inches
b. Reactor Steam Dome Pressure - Low (B21-PS-N021A,B,C,D)	410 $\pm$ 15 psig	410 $\pm$ 15 psig
c. Drywell Pressure - High (E11-PS-N011A,B,C,D)	$\leq$ 2 psig	$\leq$ 2 psig
d. Time Delay Relay	14 $\leq$ t $\leq$ 16 secs	14 $\leq$ t $\leq$ 16 secs
e. Bus Power Monitor (E21-K1A,B)	NA	NA
2. LPCI MODE OF RHR SYSTEM		
a. Drywell Pressure - High (E11-PS-N011A,B,C,D)	$\leq$ 2 psig	$\leq$ 2 psig
b. Reactor Vessel Water Level - Low, Level #3 (B21-LIS-N031A,B,C,D)	$\geq$ -147.5 inches	$\geq$ -147.5 inches
c. Reactor Vessel Shroud Level (B21-LITS-N036 and B21-LITS-N037)	$\geq$ 39" below TAF*	$\geq$ 39" below TAF*
d. Reactor Steam Dome Pressure - Low (B21-PS-N021A,B,C,D)		
1. RHR Pump Start and LCPI Valve Actuation	410 $\pm$ 15 psig	410 $\pm$ 15 psig
2. Recirculation Pump Discharge Valve Actuation	310 $\pm$ 15 psig	310 $\pm$ 15 psig
e. RHR Pump Start - Time Delay Relay	9 $\leq$ t $\leq$ 11 seconds	9 $\leq$ t $\leq$ 11 seconds
f. Bus Power Monitor (E11-K106A,B)	NA	NA

*Top of the active fuel.

TABLE 3.3.3-2 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION AND INSTRUMENT NUMBER	TRIP SETPOINT	ALLOWABLE VALUE
3. HPCI SYSTEM		
a. Reactor Vessel Water Level - Low, Level #2 (B21-LIS-N031A,B,C,D)	≥ -38 inches	≥ -38 inches
b. Drywell Pressure-High (E11-PS-N011A,B,C,D)	≤ 2 psig	≤ 2 psig
c. Condensate Storage Tank Level - Low (E41-LS-N002, E41-LS-N003)	≥ 23'4"	≥ 23'4"
d. Suppression Chamber Water Level - High* (E41-LSH-N015A,B,)	≤ -2 feet	≤ -2 feet
e. Bus Power Monitor (E41-K55 and E41-K56)	NA	NA
4. ADS		
a. Drywell Pressure-High (E11-PS-N010A,B,C,D)	≤ 2 psig	≤ 2 psig
b. Reactor Vessel Water Level - Low, Level #3 (B21-LIS-N031A,B,C,D)	≥ -147.5 inches	≥ -147.5 inches
c. ADS Timer (B21-TDPU-K5A,B)	≤ 120 seconds	≤ 120 seconds
d. Core Spray Pump Discharge Pressure - High (E21-PS-N008A,B and E21-PS-N009A,B)	≥ 100 psig	≥ 100 psig
e. RHR (LPCI MODE) Pump Discharge Pressure - High (E11-PS-N016A,B,C,D and E11-PS-N020A,B,C,D)	≥ 100 psig	≥ 100 psig
f. Bus Power Monitor (B21-K1A,B)	NA	NA

*Suppression chamber water level zero is the torus centerline minus 1 inch.

TABLE 3.3.3-2 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

FUNCTIONAL UNIT	TRIP VALUE	ALLOWABLE VALUES
5. LOSS OF POWER		
a. 4.16 kv Emergency Bus Undervoltage (Loss of Voltage)*	a. 4.16 kv Basis - 2940 ± 161 volts b. 120 v Basis - 84 ± 4.6 volts c. ≤ 10 sec. time delay	2940 ± 315 volts 84 ± 9 volts ≤ 10 sec. time delay
b. 4.16 kv Emergency Bus Undervoltage (Degraded Voltage)	a. 4.16 kv Basis - 3727 ± 9 volts b. 120 v Basis - 106.5 ± 0.25 volts c. 10 ± 0.5 sec. time delay	3727 ± 21 volts 106.5 ± 0.60 volts 10 ± 1.0 sec. time delay

*This is an inverse time delay voltage relay. The voltages shown are the maximum that will not result in a trip. Lower voltage conditions will result in decreased trip times.

TABLE 3.3.3-3

EMERGENCY CORE COOLING SYSTEM RESPONSE TIMES

ECCS	RESPONSE TIME (Seconds)
1. CORE SPRAY SYSTEM	≤ 27
2. LPCI MODE of RHR SYSTEM	≤ 40
3. HIGH PRESSURE COOLANT INJECTION SYSTEM	≤ 30
4. AUTOMATIC DEPRESSURIZATION SYSTEM	NA
5. LOSS OF POWER	NA

TABLE 4.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS IN WHICH SURVEILLANCE REQUIRED
5. LOSS OF POWER				
a. 4.16 kv Emergency Bus Undervoltage (Loss of Voltage)	NA	NA	R	1, 2, 3, 4*, 5*
b. 4.16 kv Emergency Bus Undervoltage (Degraded Voltage)	S	M	R	1, 2, 3, 4*, 5*

*Required when EFS equipment is required to be OPERABLE.

TABLE 3.3.4-1 (Continued)

CONTROL ROD WITHDRAWAL BLOCK INSTRUMENTATION

NOTE

* When THERMAL POWER exceeds the preset power level of the RWM and RSCS.

a. The minimum number of OPERABLE CHANNELS may be reduced by one for up to 2 hours in one of the trip systems for maintenance and/or testing except for Rod Block Monitor function.

b. This function is bypassed if detector is reading > 100 cps or the IRM channels are on range 3 or higher.

c. This function is bypassed when the associated IRM channels are on range 8 or higher.

d. A total of 6 IRM instruments must be OPERABLE.

e. This function is bypassed when the IRM channels are on range 1.

TABLE 3.3.4-2

CONTROL ROD WITHDRAWAL BLOCK INSTRUMENTATION SETPOINTS

TRIP FUNCTION AND INSTRUMENT NUMBER	TRIP SETPOINT	ALLOWABLE VALUE
1. APRM (C51-APRM-CH.A,B,C,D,E,F)		
a. Upscale (Flow Biased)	$\leq (0.66\ W + 42\%)\ \frac{T^*}{MTPF}$	$\leq (0.66\ W + 42\%)\ \frac{T^*}{MTPF}$
b. Inoperative	NA	NA
c. Downscale	$\geq$ 3/125 of full scale	$\geq$ 3/125 of full scale
d. Upscale (Fixed)	$\leq$ 12% of RATED THERMAL POWER	$\leq$ 12% of RATED THERMAL POWER
2. ROD BLOCK MONITOR (C51-RBM-CH.A,B)		
a. Upscale	$\leq (0.66W + 39\%)\ \frac{T^*}{MTPF}$	$\leq (0.66\ W + 39\%)\ \frac{T^*}{MTPF}$
b. Inoperative	NA	NA
c. Downscale	$\geq$ 3/125 of full scale	$\geq$ 3/125 of full scale
3. SOURCE RANGE MONITORS (C51-SRM-K600A,B,C,D)		
a. Detector not full in	NA	NA
b. Upscale	$\leq 1 \times 10^5$ cps	$\leq 1 \times 10^5$ cps
c. Inoperative	NA	NA
d. Downscale	$\geq$ 3 cps	$\geq$ 3 cps
4. INTERMEDIATE RANGE MONITORS (C51-IRM-K601A,B,C,D,E,F,G,H)		
a. Detector not full in	NA	NA
b. Upscale	$\leq$ 108/125 of full scale	$\leq$ 108/125 of full scale
c. Inoperative	NA	NA
d. Downscale	$\geq$ 3/125 of full scale	$\geq$ 3/125 of full scale

*T=2.60 for 7 x 7 fuel.
T=2.45 for 8 x 8 fuel.
T=2.48 for 8 x 8R fuel.
T=2.48 for P8 x 8R fuel.

TABLE 3.3.5.7-1 (Continued)

INSTRUMENT LOCATION		MINIMUM INSTRUMENTS OPERABLE		
		FLAME	HEAT	SMOKE
4. Service Water Building				
Zone 1	4'	0	0	6
Zone 2	20	0	0	5
5. AOG Building				
Zone 1	20'	1	0	0
Zone 2	20'	1	0	0
Zone 3	20'	1	5	1
Zone 4	37' - 49'	1	6	0

3/4.3.6 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.6.1 The anticipated transient without scram recirculation pump trip (ATWS-RPT) system instrumentation trip systems shown in Table 3.3.6.1-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.6.1-2.

APPLICABILITY: CONDITION 1.

ACTION:

a. With an ATWS recirculation pump trip system instrumentation trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.6.1-2, declare the trip system inoperable until the trip system is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. With the requirements for the Minimum Number of OPERABLE Trip Systems per Operating Pump not satisfied for one Trip Function, restore the inoperable trip system to OPERABLE status within 14 days or be in at least STARTUP within the next 8 hours.

SURVEILLANCE REQUIREMENTS

4.3.6.1.1 Each ATWS recirculation pump trip system instrumentation trip system shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequences shown in Table 4.3.6.1.1-1.

4.3.6.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed at least once per 18 months and shall include calibration of time delay relays and timers necessary for proper functioning of the trip system.

TABLE 4.3.6.1-1

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION AND INSTRUMENT NUMBER	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
1. Reactor Vessel Water Level - Low Low, Level 2 (B21-LIS-N024 A, B; B21-LIS-N025 A, B)	S	M	R
2. Reactor Vessel Pressure ~~- Low~~ High (B21-PS-N045 A, B, C, D)	NA	M	R

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.6.2 The end-of-cycle recirculation pump trip (EOC-RPT) system instrumentation channels shown in Table 3.3.6.2-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.6.2-2 and with the END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME as shown in Table 3.3.6.2-3.

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 3.3.6.2-2, 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 one hour.

c. With the number of OPERABLE channels two or more less than required by the Minimum OPERABLE Channels per Trip System requirement 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 one 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 one hour or take the ACTION required by Specification 3.2.3.

SURVEILLANCE REQUIREMENTS

4.3.6.2.1 Each end-of-cycle recirculation pump trip system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.6.2.1-1.

4.3.6.2.2. LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed at least once per 18 months and shall include calibration of time delay relays and timers necessary for proper functioning of the trip system.

4.3.6.2.3 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME of both trip systems shown in Table 3.3.6.2-3 shall be demonstrated to be within its limit at least once per 18 months. Each test shall include at least the logic of one type of channel input, turbine control valve fast closure or turbine stop valve closure, such that both types of channel inputs are tested at least once per 36 months.

TABLE 3.3.6.2-1

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM[(a)]
1. Turbine Stop Valve - Closure (EHC-SVOS-1X, 2X, 3X, 4X)	2[(b)]
2. Turbine Control Valve - Fast Closure (EHC-PSL-1756, 1757, 1758, 1759)	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) These functions are bypassed when turbine first stage pressure is equivalent to THERMAL POWER less than 30% of RATED THERMAL POWER.

TABLE 3.3.6.2-2

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. Turbine Stop Valve-Closure (EHC-SVOS-1X, 2X, 3X, 4X)	$\leq$ 10% closed	$\leq$ 10% closed
2. Turbine Control Valve-Fast Closure (EHC-PSL-1756, 1757, 1758, 1759)	$\geq$ 500 psig	$\geq$ 500 psig

TABLE 3.3.6.2-3

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)
1. Turbine Stop Valve-Closure (EHC-SVOS-1X, 2X, 3X, 4X)	≤ 0.175
2. Turbine Control Valve-Fast Closure (EHC-PSL-1756, 1757, 1758, 1759)	≤ 0.175

TABLE 4.3.6.2.1-1

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
1. Turbine Stop Valve-Closure (EHC-SVOS-1X, 2X, 3X, 4X)	M*	R
2. Turbine Control Valve-Fast Closure (EHC-PSL-1756, 1757, 1758, 1759)	M*	R

*Including trip system logic testing.

3/4.7.1 SERVICE WATER SYSTEMS

RESIDUAL HEAT REMOVAL SERVICE WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.1 Two independent Residual Heat Removal Service Water (RHRSW) System subsystems shall be OPERABLE with each subsystem comprised of:

a. Two pumps, and

b. An OPERABLE flow path for heat removal capable of taking suction from the intake canal via the service water system and transferring the water through an RHR heat exchanger.

APPLICABILITY: CONDITIONS 1, 2 and 3.

ACTION:

a. With one RHRSW pump inoperable, operation may continue and the provisions of Specification 3.0.4 are not applicable; restore the inoperable pump to OPERABLE status within 31 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one RHRSW subsystem inoperable, operation may continue and the provisions of Specification 3.0.4 are not applicable; restore the inoperable subsystem 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.

c. With both RHRSW subsystems inoperable, restore at least one subsystem 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

4.7.1.1 Each residual heat removal service water subsystem shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve in the flow path that is not locked, sealed or otherwise secured in position, is in its correct position, and

b. At least once per 92 days by verifying that each pump develops a pump ΔP of at least 232 psi at a flow of 4000 gpm measured through the heat exchanger with a minimum suction pressure of 20 psig.

SERVICE WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.2 The service water system nuclear header shall be OPERABLE with at least three OPERABLE service water pumps.

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

ACTION:

a. In CONDITION 1, 2, or 3:

1. With only two service water pumps OPERABLE, restore at least three pumps 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.

2. With only one service water pump OPERABLE, restore at least two pumps to OPERABLE status within 72 hours and restore at least three pumps to OPERABLE status within 7 days from the time of the initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In Condition 4 or 5, with only one service water pump OPERABLE, restore at least two service water pumps to OPERABLE status within 7 days or declare the core spray system, the LPCI system and the diesel generator inoperable and take the ACTION required by Specifications 3.5.3.1, 3.5.3.2 and 3.8.1.2.

SURVEILLANCE REQUIREMENTS

4.7.1.2 The service water system shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power operated or automatic) servicing safety related equipment that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. At least once per 18 months during shutdown, by verifying that each automatic valve servicing safety related equipment actuates to its correct position on the appropriate ECCS actuation test signals.

TABLE 3.7.5-1 (Continued)

SAFETY RELATED HYDRAULIC SNUBBERS*

SNUBBER NO.	SYSTEM SNUBBER INSTALLED ON, LOCATION AND ELEVATION		ACCESSIBLE OR INACCESSIBLE	HIGH RADIATION ZONE**	ESPECIALLY DIFFICULT TO REMOVE
Reactor Recirculation System (Continued)					
2B32-SSA6	Drywell (Cont'd)	27'	I	No	No
SSB6		27'	I	No	No
SSB9A		30'	I	No	No
SSB9B		30'	I	No	No
SSA10		24'	I	No	No
SSA11		11'	I	No	No
SSB11		4'	I	No	No
SSA12A		30'	I	No	No
SSA12B		30'	I	No	No
SSB12A		30'	I	No	No
SSB12B		30'	I	No	No
Reactor Vessel Instrumentation					
2PS-3554	Drywell	63'	I	No	No
3567		65'	I	No	No
3613		90'	I	No	No
3705A		32'	I	No	No
3705B		32'	I	No	No
3706		32'	I	No	No
3707		32'	I	No	No
3708		32'	I	No	No
3709		32'	I	No	No
3710		32'	I	No	No
3722A		82'	I	No	No
3722B		82'	I	No	No

TABLE 3.7.5-1 (Continued)

SAFETY RELATED HYDRAULIC SNUBBERS*

SNUBBER NO.	SYSTEM SNUBBER INSTALLED ON, LOCATION AND ELEVATION		ACCESSIBLE OR INACCESSIBLE	HIGH RADIATION ZONE**	ESPECIALLY DIFFICULT TO REMOVE
	Off Gas System				
2PS-3417	Nitrogen and Off Gas Bldg.	31'	A	No	No
3418A		33'	A	No	No
3418B		33'	A	No	No
3419A		33'	A	No	No
3419B		33'	A	No	No
3423		37'	A	No	No
	Reactor Feedwater System				
2B21-2SS3	Drywell	38'	I	No	No
2SS4		56'	I	No	No
3SS6		41'	I	No	No
3SS9		39'	I	No	No
3SS11		41'	I	No	No
3SS12		40'	I	No	No
3SS13		61'	I	No	No
5SS17		38'	I	No	No
5SS18		56'	I	No	No
6SS20		41'	I	No	No
6SS23		39'	I	No	No
6SS25		41'	I	No	No
6SS26		40'	I	No	No
6SS27		63'	I	No	No
1SS227		34'	I	No	No
1SS228		38'	I	No	No
2SS229		53'	I	No	No
2SS230		62'	I	No	No

3/4.7.8 FIRE BARRIER PENETRATIONS

LIMITING CONDITIONS FOR OPERATION

3.7.8 All fire barrier penetrations, including cable penetration barriers, fire doors and fire dampers, in fire zone boundaries protecting safety related areas shall be functional.

APPLICABILITY: At all times.

ACTION;

a. With one or more of the above required fire barrier penetrations non-functional, within one hour establish a continuous fire watch on at least one side of the affected penetration or verify the OPERABILITY of fire detectors on at least one side of the non-functional fire barrier and establish an hourly fire watch patrol. Restore the non-functional fire barrier penetration(s) to functional status within 7 days or, in lieu of any other report required by Specification 6.9.1, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 30 days outlining the action taken, the cause of the non-functional penetration and plans and schedule for restoring the fire barrier penetration(s) to functional status.

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

SURVEILLANCE REQUIREMENTS

4.7.8 Each of the above required fire barrier penetrations shall be verified to be functional:

a. At least once per 18 months by a visual inspection, and

b. Prior to restoring a fire barrier penetration to functional status following repairs or maintenance, by performance of a visual inspection of the affected fire barrier penetration.

BASES

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.

3.0.1 This specification states the applicability of each specification in terms of defined OPERATIONAL 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 ACTION to be taken for circumstances not directly provided for in the ACTION statements and whose occurrence would violate the intent of specification. For example, Specification 3.5.1 calls for the HPCI to be OPERABLE and specifies explicit requirements if it become inoperable. Under the terms of Specification 3.0.3 if the required additional systems are not OPERABLE, the facility is to be placed in HOT SHUTDOWN within the next 6 hours and be in COLD SHUTDOWN within the following 30 hours. The unit shall be brought to the required OPERATIONAL CONDITION within the required times by promptly initiating and carrying out an orderly shutdown. It is intended that this guidance also apply whenever an ACTION statement requires a unit to be in STARTUP within 2 hours or in HOT SHUTDOWN within 6 hours.

3.0.4 This specification provides that entry into an OPERABLE 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 insure that facility 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.

APPLICABILITY

BASES

4.0.1 This specification provides that surveillance activities necessary to insure the Limiting Conditions for Operation are met and will be performed during the OPERATIONAL CONDITIONS for which the Limiting Conditions for Operation are applicable. Provisions for additional surveillance activities to be performed without regard to the applicable OPERATIONAL CONDITIONS are provided in the individual Surveillance Requirements.

4.0.2 The provisions of this specification provide allowable tolerances for performing surveillance activities beyond those specified in the nominal surveillance interval. These tolerances are necessary to provide operational flexibility because of scheduling and performance considerations. considerations. The phrase "at least" associated with a surveillance frequency does not negate this allowable tolerance value and permits the performance of more frequent surveillance activities.

The tolerance values, taken either individually or consecutively over 3 test intervals, are sufficiently restrictive to ensure that the reliability associated with the surveillance activity is not significantly degraded beyond that obtained from the nominal specified interval.

4.0.3 The provisions of this specification set forth the criteria for determination of compliance with the OPERABILITY requirements of the Limiting Conditions for Operation. Under this criteria, equipment, systems or components are assumed to be OPERABLE if the associated surveillance activities have been satisfactorily performed within the specified time interval. Nothing in this provision is to be construed as defining equipment, systems or components OPERABLE, when such items are found or known to be inoperable although still meeting the Surveillance Requirements.

4.0.4 This specification ensures that surveillance activities associated with a Limiting Condition for Operation have been performed within the specified time interval prior to entry into an applicable CONDITION. The intent of this provision is to ensure that surveillance activities have been satisfactorily demonstrated on a current basis as required to meet the OPERABILITY requirements of the Limiting Condition for Operation.

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 the Final Acceptance Criteria (FAC) issued in June 1971 considering the postulated effects of fuel pellet densification.

3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

This specification assures that the peak cladding tempeature following the postulated design basis loss-of-coolant accident will not exceed the limit specified in 10 CFR 50, Appendix K.

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 a 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 APHGR is this LHGR of the highest powered rod divided by its local peaking factor. The limiting value for APLHGR is shown in Figures 3.2.1-1, 3.2.1-2, 3.2.1-3, 3.2.1-4, 3.2.1-5, 3.2.1-6, 3.2.1-7 and 3.2.1-8.

The calculational procedure used to establish the APLHGR shown on Figures 3.2.1-1, 3.2.1-2, 3.2.1-3, 3.2.1-4, 3.2.1-5, 3.2.1-6, 3.2.1-7 and 3.2.1-8 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 Figures 3.2.1-1, 3.2.1-2, 3.2.1-3, 3.2.1-4, 3.2.1-5, 3.2.1-6, 3.2.1-7 and 3.2.1-8; (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; (4) The effects of core spray entrainment and counter-current 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.

Bases Table B 3.2.1-1

SIGNIFICANT INPUT PARAMETERS TO THE

LOSS-OF-COOLANT ACCIDENT ANALYSIS

FOR BRUNSWICK - UNIT 2

Plant Parameters:

Core Thermal Power	2531 Mwt which corresponds to 105% of rated steam flow
Vessel Steam Output	10.96×10^6 Lbm/h which corresponds to 105% of rated steam flow
Vessel Steam Dome Pressure	1055 psia
Recirculation Line Break Area for Large Breaks	
a. Discharge	2.4 ft^2 (DBA); 1.9 ft^2 (80% DBA)
b. Suction	4.2 ft^2
Number of Drilled Bundles	520

Fuel Parameters:

FUEL TYPES	FUEL BUNDLE GEOMETRY	PEAK TECHNICAL SPECIFICATION LINEAR HEAT GENERATION RATE (kw/ft)	DESIGN AXIAL PEAKING FACTOR	INITIAL MINIMUM CRITICAL POWER** RATIO
Reload Core	8 x 8	13.4	1.4	1.20
	7 x 7	18.5	1.5	1.20

A more detailed list of input to each model and its source is presented in Section II of Reference 1.

* This power level meets the Appendix K requirement of 102%.

** To account for the 2% uncertainty in bundle power required by Appendix K, the SCAT calculation is performed with an MCPR of 1.18 (i.e., 1.2 divided by 1.02) for a bundle with an initial MCPR of 1.20.

3/4.2.2 APRM SETPOINTS

The fuel cladding integrity safety limits of Specification 2.1 were based on a TOTAL PEAKING FACTOR of 2.60 for 7 x 7 fuel, 2.45 for 8 x 8 fuel and 2.48 for 8 x 8R and P8 x 8R fuel. The scram setting and rod block functions of the APRM instruments must be adjusted to ensure that the MCPR does not become less than 1.0 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 peak flux indicates a TOTAL PEAKING FACTOR greater than 2.60 for 7 x 7 fuel, 2.45 for 8 x 8 fuel and 2.48 for 8 x 8R and P8 x 8R fuel. The method used to determine the design TPF shall be consistent with the method used to determine the MTPF.

3/4.2.3 MINIMUM CRITICAL POWER RATIO

The required operating limit MCPR's at steady state operating conditions as specified in Specification 3.2.3 are derived from the established fuel cladding integrity Safety Limit MCPR of 1.07, and an analysis of abnormal operational transients.[1] 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 as given in Specification 2.2.1.

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 which determines the required steady state MCPR limit is the turbine trip with failure of the turbine bypass. This transient yields the largest Δ MCPR. When added to the Safety Limit MCPR of 1.07 the required minimum operating limit MCPR of Specification 3.2.3 is obtained. Prior to the analysis of abnormal operational transients an initial fuel bundle MCPR was determined. This parameter is based on the bundle flow calculated by a GE multi-channel steady state flow distribution model as described in Section 4.4 of NEDO-20360[4] and on core parameters shown in Reference 3, response to Items 2 and 9.

MINIMUM CRITICAL POWER RATIO (Continued)

The evaluation of a given transient begins with the system initial parameters shown in Attachment 5 of Reference 6 that are input to a GE-core dynamic behavior transient computer program described in NEDO-10802(5). Also, the void reactivity coefficients that were input to the transient calculational procedure are based on a new method of calculation termed NEV which provides a better agreement between the calculated and plant instrument power distributions. 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 SCAT code described in NEDO-20566(1). The principal result of this evaluation is the reduction in MCPR caused by the transient.

The purpose of the K_f factor is to define operating limits at other than rated flow conditions. At less than 100% flow the required MCPR is the product of the operating limit MCPR and the K_f factor. Specifically, the K_f factor provides the required thermal margin to protect against a flow increase transient. The most limiting transient initiated from less than rated flow conditions is the recirculation pump speed up caused by a motor-generator speed control failure.

For operation in the automatic flow control mode, the K_f factors assure that the operating limit MCPR of Specification 3.2.3 will not be violated should the most limiting transient occur at less than rated flow. In the manual flow control mode, the K_f factors assure that the Safety Limit MCPR will not be violated should the most limiting transient occur at less than rated flow.

The K_f factor values shown in Figure 3.2.3-1 were developed generically which are applicable to all BWR/2, BWR/3, and BWR/4 reactors. The K_f factors were derived using the flow control line corresponding to rated thermal power at rated core flow.

For the manual flow control mode, the K_f factors were calculated such that the maximum flow state (as limited by the pump scoop tube set point) and the corresponding core power (along the rated flow control line), the limiting bundle's relative power was adjusted until the MCPR was slightly above the Safety Limit. Using this relative bundle power, the MCPR's were calculated at different points along the rated flow control line corresponding to different core flows. The ratio of the MCPR calculated at a given point of core flow, divided by the operating limit MCPR determines the K_f.

MONITORING INSTRUMENTATION (Continued)

3/4.3.5.2 REMOTE SHUTDOWN MONITORING INSTRUMENTATION

The OPERABILITY of the remote shutdown monitoring instrumentation ensures that sufficient capability is available to permit shutdown and maintenance of HOT SHUTDOWN of the facility from locations outside of the control room. This capability is required in the event control room habitability is lost and is consistent with General Design Criterion 19 of CFR 50.

3/4.3.5.3 POST-ACCIDENT MONITORING INSTRUMENTATION

The OPERABILITY of the post-accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess important variables following an accident. This capability is consistent with the recommendations of Regulatory Guide 1.97 "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," December 1975.

3/4.3.5.4 SOURCE RANGE MONITORS

The source range monitors provide the operator with information on the status of the neutron level in the core at very low power levels during startup. At these power levels reactivity additions should not be made without this flux level information available to the operator. When the intermediate range monitors are on scale adequate information is available without the SRM's and they can be retracted.

3/4.3.5.5 CHLORINE DETECTION SYSTEM

The OPERABILITY of the chlorine detection systems ensures that an accidental chlorine release will be detected promptly and the necessary protective actions will be automatically initiated to provide protection for control room personnel. Upon detection of a high concentration of chlorine the control room emergency ventilation system will automatically isolate the control room and initiate operation in the recirculation mode to provide the required protection. The detection systems required by this specification are consistent with the recommendations of Regulatory Guide 1.95 "Protection of Nuclear Power Plant Control Room Operators Against an Accidental Chlorine Release."

MONITORING INSTRUMENTATION (Continued)

3/4.3.5.6 CHLORIDE INTRUSION MONITORS

The chloride intrusion monitors provide adequate warning of any leakage in the condenser or hotwell so that actions can be taken to mitigate the consequences of such intrusion in the reactor coolant system. With only a minimum number of instruments available increased sampling frequency provides adequate information for the same purpose.

3/4.3.5.7 FIRE DETECTION INSTRUMENTATION

OPERABILITY of the fire detection instrumentation ensure that adequate warning capability is available for the prompt detection of fires. This capability is required in order to detect and locate fires in their early stages. Prompt detection of fires will reduce the potential for damage to safety related equipment and is an integral element in the overall facility fire protection program.

In the event that a portion of the fire detection instrumentation is inoperable, increasing the frequency of fire patrols in the affected areas is required to provide detection capability until the inoperable instrumentation is restored to OPERABILITY.

3/4.3.6 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within an envelope of study events given in General Electric Company Topical Report NEDO-10349, dated March, 1971.

The end-of-cycle recirculation pump trip (EOC-RPT) system is a part of the Reactor Protection System and is a safety supplement to the reactor trip. The purpose of the EOC-RPT is to recover the loss of thermal margin which occurs at the end-of-cycle. The physical phenomenon involved is that the void reactivity feedback due to a pressurization transient can add positive reactivity to the reactor system at a faster rate than the control rods add negative scram reactivity. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order to reduce the void collapse in the core during two of the most limiting pressurization events. The two events for which the EOC-RPT protective

RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued)

feature will function are closure of the turbine stop valves and fast closure of the turbine control valves.

A fast closure sensor from each of two turbine control valves provides input to one EOC-RPT system; a fast closure sensor from each of the other two turbine control valves provides input to the second EOC-RPT system. similarly, a position switch for each of two turbine stop valves provides input to one EOC-RPT system; a position switch for each of the other two turbine stop valves provides input to the other EOC-RPT system. For each EOC-RPT system, the sensor relay contacts are arranged to form a 2-out-of-2 logic for closure of the turbine stop valves. The operation of either logic will actuate the EOC-RPT system and trip both recirculation pumps.

Each EOC-RPT system may be manually bypassed by use of a keyswitch which is administratively controlled. The manual bypasses and the automatic operating bypass at < 30% of RATED THERMAL POWER are annunciated in the control room.

3/4.7.5 HYDRAULIC SNUBBERS (Continued)

To provide further assurance of snubber reliability, a representa-
tive sample of the installed snubbers will be functionally tested during
plant shutdowns at 18 month intervals. These tests will include stroking
of the snubbers to verify proper piston movement, lock-up and bleed.
Observed failures of these sample snubbers will require functional
testing of additional units. To minimize personnel exposures, snubbers
installed in high radiation zones or in especially difficult to remove
locations may be exempted from these functional testing requirements
provided the OPERABILITY of these snubbers was demonstrated during
functional testing at either the completion of their fabrication or at a
subsequent ~~date.~~

3/4.7.6 SEALED SOURCE CONTAMINATION

The limitations on sealed source removable contamination ensure
that the total body or individual organ irradiation does not exceed
allowable limits in the event of ingestion or inhalation of the source
material. The limitations on removable contamination for sources
requiring leak testing, including alpha emitters, is based on 10 CFR
70.39(c) limits for plutonium. Quantities of interest to this speci-
fication which are exempt from the leakage testing are consistent with
the criteria of 10 CFR Part 30.11-20 and 70.19. Leakage from sources
excluded from the requirements of this specification is not likely to
represent more than one maximum permissible body burden for total body
irradiation if the source material is inhaled or ingested.

3/4.7.7 FIRE SUPPRESSION SYSTEMS

The OPERABILITY of the fire suppression systems ensures that ade-
quate fire suppression capability is available to confine and extinguish
fires occurring in any portion of the facility where safety related
equipment is located. The fire suppression system consists of the water
system, spray and/or sprinklers, CO_2, and fire hose stations. The
collective capability of the fire suppression systems is adequate to
minimize potential damage to safety related equipment and is a major
element in the facility fire protection program.

In the event that portions of the fire suppression systems are in-
operable, alternate backup fire fighting equipment is required to be
made available in the affected areas until the inoperable equipment is
restored to service.

3/4.7.7 FIRE SUPPRESSION SYSTEMS (Continued)

In the event the fire suppression water system becomes inoperable, immediate corrective measures must be taken since this system provides the major fire suppression capability of the plant. The requirement for a twenty-four hour report to the Commission provides for prompt evaluation of the acceptability of the corrective measures to provide adequate fire suppression capability for the continued protection of the nuclear plant.

3/4.7.8 FIRE BARRIER PENETRATIONS

The functional integrity of the fire barrier penetrations ensures that fires will be confined or adequately retarded from spreading to adjacent portions of the facility. This design feature minimizes the possibility of a single fire rapidly involving several areas of the facility prior to detection and extinguishment. The fire barrier penetrations are a passive element in the facility fire protection program and are subject to periodic inspections.

The barrier penetrations, including cable penetration barriers, fire doors and dampers are considered functional when the visually observed condition is the same as the as-designed condition. For those fire barrier penetrations that are not in the as-designed condition, an evaluation shall be performed to show that the modification has not degraded the fire rating of the fire barrier penetration.

During periods of time when the barriers are not functional, either 1) a continuous fire watch is required to be maintained in the vicinity of the affected barrier, or 2) the fire detectors on at least one side of the affected barrier must be verified OPERABLE and a hourly fire watch patrol established until the barrier is restored to functional status.

6.0 ADMINISTRATIVE CONTROLS

6.1 RESPONSIBILITY

6.1.1 The General Manager shall be responsible for overall facility operation and shall delegate in writing the succession to this responsibility during his absence.

6.2 ORGANIZATION

OFFSITE

6.2.1 The offsite organization for facility management and technical support shall be as shown on Figure 6.2.1-1.

FACILITY STAFF

6.2.2 The Facility organization shall be as shown on Figures 6.2.2-1 and 6.2.2-2 and:

a. Each on duty shift shall be composed of at least the minimum shift crew composition shown in Table 6.2.2-1.

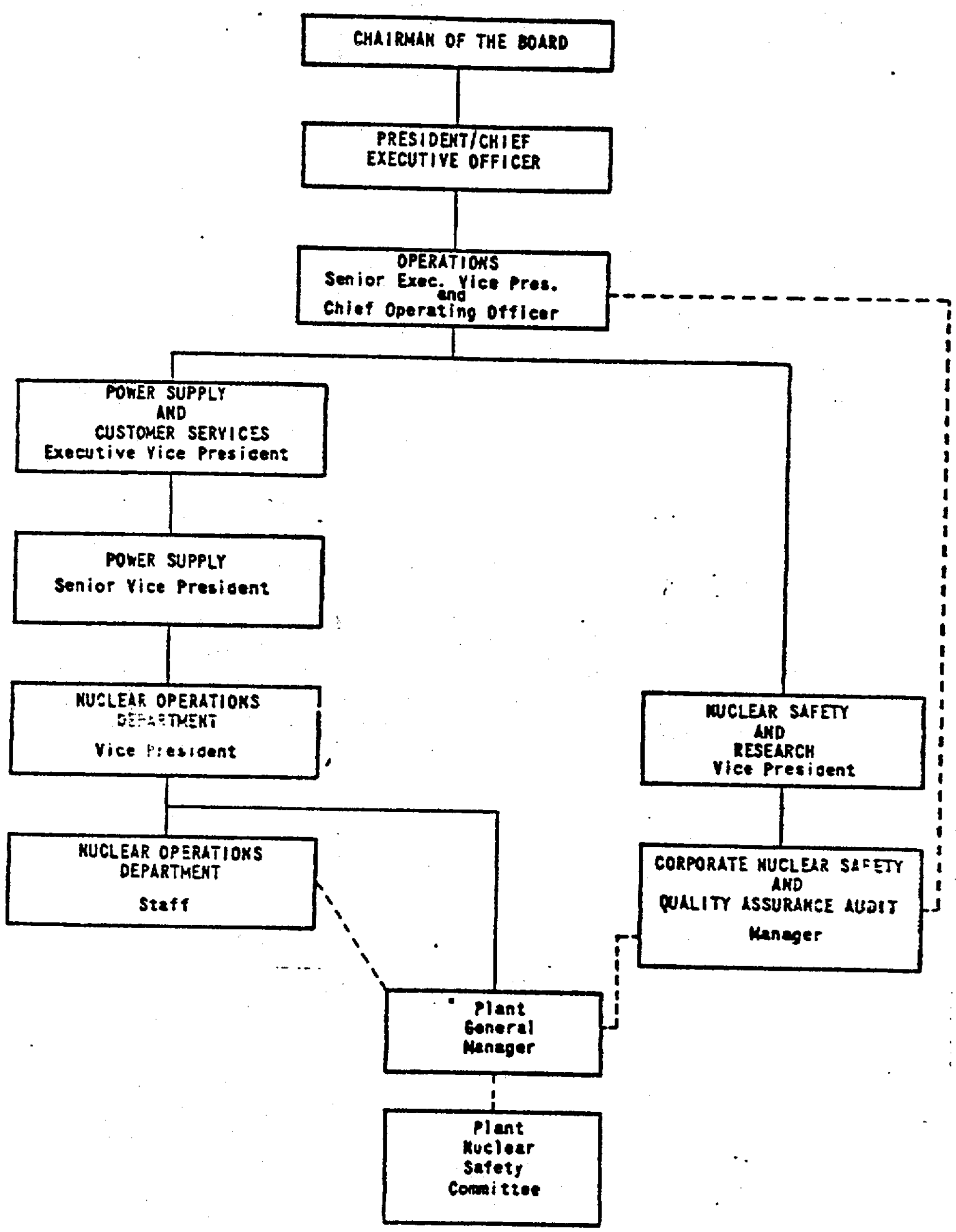
b. At least one licensed Operator shall be in the control room for each reactor containing fuel.

c. At least two licensed Operators shall be present in the control room for each reactor in the process of start-up, scheduled reactor shutdown and during recovery from reactor trips.

d. An individual qualified to implement radiation protection procedures shall be on site when fuel is in either reactor.

e. All CORE ALTERATIONS shall be directly supervised by either a licensed Senior Reactor Operator or Senior Reactor Operator Limited to Fuel Handling who has no other concurrent responsibilities during this operation.

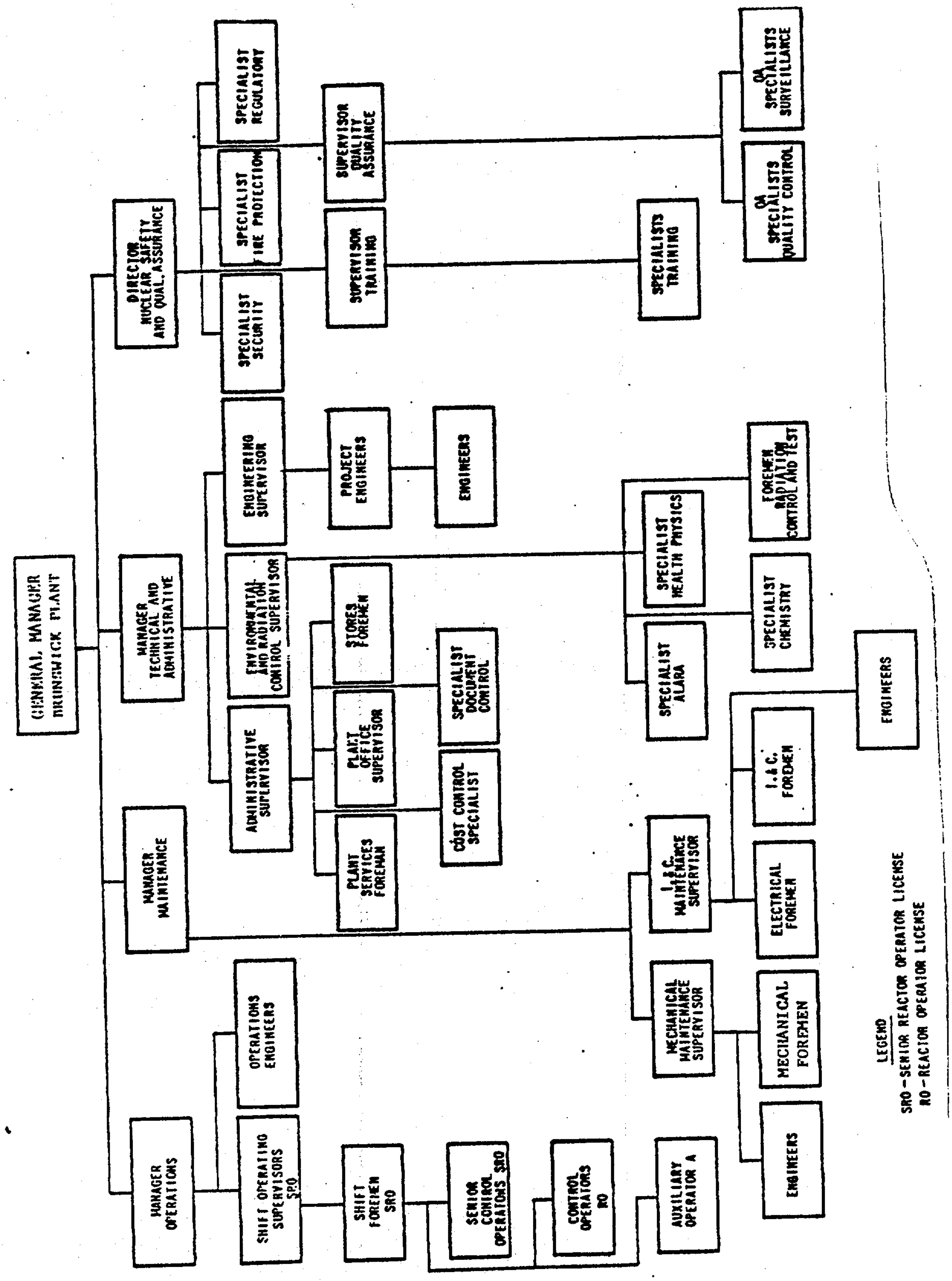
f. A Fire Brigade of at least five members shall be maintained onsite at all times. The Fire Brigade shall not include the minimum shift crew shown in Table 6.2.2-1 or any personnel required for other essential functions during a fire emergency.



*Responsible for performance and monitoring of Fire Protection Program.

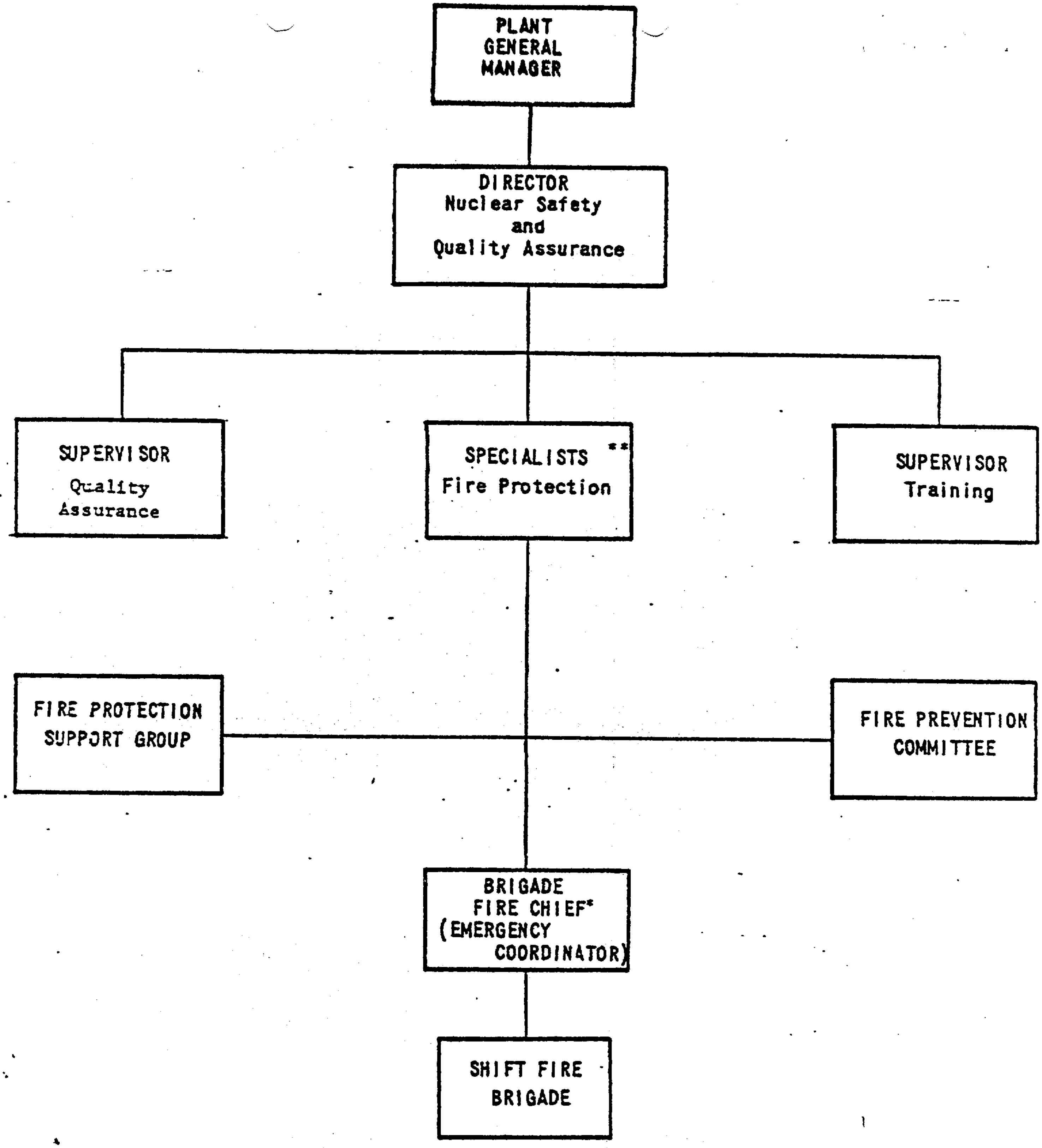
MANAGEMENT ORGANIZATION CHART

FIGURE 6.2.1-1



FACILITY ORGANIZATION

Figure 6.2.2-1



PLANT FIRE PROTECTION ORGANIZATION

*Number of Brigade Fire Chiefs varies with shift organization.
**One Engineer is assigned the duties of the plant fire chief.

FIGURE 6.2.2-2

TABLE 6.2.2-1

MINIMUM SHIFT CREW COMPOSITION#

Condition of Unit 1 - Unit 2 in CONDITION 1, 2 or 3

LICENSE CATEGORY	APPLICABLE OPERATIONAL CONDITIONS	
	1, 2, 3	4 & 5
SOL**	2	2*
OL**	3	2
Non-Licensed	4	3

Condition of Unit 1 - Unit 2 in CONDITION 4 or 5

LICENSE CATEGORY	APPLICABLE OPERATIONAL CONDITIONS	
	1, 2, 3	4 & 5
SOL**	2	1*
OL**	2	2
Non-Licensed	3	3

Condition of Unit 1 - No Fuel in Unit 2

LICENSE CATEGORY	APPLICABLE OPERATIONAL CONDITIONS	
	1, 2, 3	4 & 5
SOL	1	1*
OL	2	1
Non-Licensed	2	1

* Does not include the licensed Senior Reactor Operator or Senior Reactor Operator Limited to Fuel Handling, supervising CORE ALTERATIONS.

**Assumes each individual is licensed on both plants.

\# Shift crew composition, including an individual qualified in radiation protection procedures, may be less than the minimum requirements 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 Table 6.2.2-1.

6.3 FACILITY STAFF QUALIFICATIONS

6.3.1 Each member of the facility staff shall meet or exceed the minimum qualifications of ANSI N18.1-1971 for comparable position, except for the Environmental and Radiation Control Supervisor who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975.

6.4 TRAINING

6.4.1 A retraining and replacement training program for the facility staff shall be maintained under the direction of the Training Supervisor and shall meet or exceed the requirements and recommendations of Section 5.5 of ANSI N18.1-1971 and Appendix "A" of 10 CFR Part 55.

6.4.2 A training program for the Fire Brigade shall be maintained under the direction of the Plant Fire Chief and shall meet or exceed the requirements of Section 27 of the NFPA Code-1975.

6.5 REVIEW AND AUDIT

6.5.1 PLANT NUCLEAR SAFETY COMMITTEE (PNSC)

FUNCTION

6.5.1.1 The PNSC shall function to advise the General Manager on all matters related to nuclear safety.

COMPOSITION

6.5.1.2 The PNSC shall be composed of the:

Chairman:	Plant General Manager
Vice Chairman:	Operations Manager, Maintenance Manager, Technical - Administrative Manager or Director - Nuclear Safety and QA
Secretary:	Administrative Supervisor
Member:	Maintenance Supervisor (I&C)
Member:	Maintenance Supervisor (Mechanical)
Member:	Engineering Supervisor
Member:	Environmental and Radiation Control Supervisor
Member:	Quality Assurance Supervisor
Member:	Shift Operating Supervisors
Member:	Training Supervisor

ALTERNATES

6.5.1.3 All alternate members shall be appointed in writing by the PNSC Chairman to serve on a temporary basis; however, no more than two alternates shall participate as voting members in PNSC activities at any one time.

MEETING FREQUENCY

6.5.1.4 The PNSC shall meet at least once per calendar month and as convened by the PNSC Chairman or his designated alternate.

QUORUM

6.5.1.5 A quorum of the PNSC shall consist of the Chairman or Vice Chairman and three members including alternates.

RESPONSIBILITIES

6.5.1.6 The PNSC shall be responsible for:

a. Review of 1) all procedures required by Specification 6.8 and changes thereto, 2) any other proposed procedures or changes thereto as determined by the General Manager to affect nuclear safety.

b. Review of all proposed tests and experiments that affect nuclear safety.

c. Review of all proposed changes to Technical Specifications.

d. Review of all proposed changes or modifications to plant systems or equipment that affect nuclear safety.

e. Investigation of all violations of the Technical Specifications including the preparation and forwarding of reports covering evaluation and recommendations to prevent recurrence to the Vice President - Nuclear Operations and to the Manager - Corporate Nuclear Safety and Quality Assurance Audit.

f. Review of all events requiring 24 hour notification to the Commission.

g. Review of facility operations to detect potential safety hazards.

h. Performance of special reviews, investigations and reports thereon as requested by the Manager - Corporate Nuclear Safety and Quality Assurance Audit.

i. Review of the Plant Security Plan and implementing procedures.

j. Review of the Emergency Plan and implementing procedures.

AUTHORITY

6.5.1.7 The PNSC shall:

a. Recommend to the General Manager written approval or disapproval of items considered under 6.5.1.6(a) through (d) above.

b. Render determinations in writing with regard to whether or not each item considered under 6.5.1.6(a) through (e) above constitutes an unreviewed safety question.

c. Provide written notification within 24 hours to the Vice President - Nuclear Operations and the Manager - Corporate Nuclear Safety and Quality Assurance Audit of disagreement between the PNSC and the General Manager; however, the General Manager shall have responsibility for resolution of such disagreements pursuant to 6.1.1 above.

RECORDS

6.5.1.8 The PNSC shall maintain written minutes of each meeting that, at a minimum, document the results of all PNSC activities performed under the responsibility and authority provisions of these technical specifications, and copies shall be provided to the Vice President - Nuclear Operations and to the Manager - Corporate Nuclear Safety and Quality Assurance Audit.

6.5.2 CORPORATE NUCLEAR SAFETY AND QUALITY ASSURANCE AUDIT SECTION (CNS & QAAS)

RESPONSIBILITY

6.5.2.1 The Manager - Corporate Nuclear Safety and Quality Assurance Audit, under the Vice President - Nuclear Safety and Research, is charged with the overall responsibility for administering the independent off-site review and quality assurance audit programs as follows:

a. Approves selection of the individuals to conduct off-site safety reviews and quality assurance audits.

b. Has access to the plant operating records and operating personnel in performing the independent reviews and quality assurance audits.

c. Prepares and retains written records of review and audits.

d. Assures independent safety reviews are conducted on all items required by Section 6.5.3.3 and quality assurance audits cover all items included in Section 6.5.4.1.

e. Distributes reports, records of PNSC meetings, and other records to the appropriate managers and individuals assigned to conduct the off-site safety reviews and quality assurance audits.

6.5.3 CORPORATE NUCLEAR SAFETY UNIT (CNSU)

FUNCTION

6.5.3.1 The Corporate Nuclear Safety Unit of the Corporate Nuclear Safety and Quality Assurance Audit Section shall provide independent off-site review of significant plant changes, tests, and procedures; verify that reportable occurrences are promptly investigated and corrected in a manner which reduces the probability of recurrence of such events; and detect trends which may not be apparent to a day-to-day observer.

PERSONNEL

6.5.3.2

a. Personnel assigned responsibility for independent reviews shall be specified in technical disciplines, and shall collectively have the experience and competence required to review problems in the following areas:

   1. Nuclear power plant operations
   2. Nuclear engineering
   3. Chemistry and radiochemistry
   4. Metallurgy
   5. Instrumentation and control
   6. Radiological safety
   7. Mechanical and electrical engineering
   8. Administrative controls
   9. Seismic and environmental
   10. Quality assurance practices

b. The following minimum experience requirements shall be established for those persons involved in the independent off-site safety review program:

   1. Manager of CNS and QAAS - Bachelor of Science in engineering or related field and ten (10) years related experience including five (5) years involvement with operation and/or design of nuclear power plants.

   2. Reviewers - Bachelor of Science in engineering or related field or equivalent and five (5) years related experience including three (3) years involvement with operation and/or design of nuclear power plants.

PERSONNEL (Continued)

c. An individual may possess competence in more than one specialty area. If sufficient expertise is not available within the Corporate Nuclear Safety Unit, competent individuals from other Carolina Power and Light Company organizations or outside consultants shall be utilized in performing independent off-site reviews and investigations.

d. At least three persons, qualified as discussed in Specification 6.5.2.3.b, shall review each item submitted under the requirements of Section 6.5.3.3.

e. Independent safety reviews shall be performed by personnel not directly involved with the activity or responsible for the activity.

SUBJECTS REQUIRING INDEPENDENT REVIEW

6.5.3.3 The following subjects shall be reviewed by the Corporate Nuclear Safety Unit:

a. Written safety evaluations of changes in the facility as described in the Safety Analysis Report, changes in procedures as described in the Safety Analysis Report and tests or experiments not described in the Safety Analysis Report which are completed without prior NRC approval under the provisions of 10 CFR 50.59(a)(1). This review is to verify that such changes, tests, or experiments did not involve a change in the technical specifications or an unreviewed safety question as defined in 10 CFR 50.59(a)(2).

b. Proposed changes in procedures, proposed changes in the facility, or proposed tests or experiments, any of which involves a change in the Technical Specifications or an unreviewed safety question pursuant to 10 CFR 50.59(c). Matters of this kind shall be referred to the Corporate Nuclear Safety Unit by the Plant Nuclear Safety Committee following its review, or by other functional organizational units within Carolina Power & Light Company prior to implementation.

c. Proposed changes to the Technical Specifications or this operating license.

SUBJECTS REQUIRING INDEPENDENT REVIEW (Continued)

d. Violations, deviations and reportable events, which require reporting to the NRC within 24 hours, and as defined in the plant technical specifications such as:

1. Violations of applicable codes, regulations, orders, Technical Specifications, license requirements or internal procedures or instructions having safety significance; and

2. Significant operating abnormalities or deviations from normal or expected performance of plant safety-related structures, systems, or components.

Review of events covered under this paragraph shall include the results of any investigations made and the recommendations resulting from such investigations to prevent or reduce the probability of recurrence of the event.

e. Any other matter involving safe operation of the nuclear power plant which the Manager - Corporate Nuclear Safety and Quality Assurance Audit Section deems appropriate for consideration, or which is referred to the Manager - Corporate Nuclear Safety and Quality Assurance Audit Section by the onsite operating organization or by other fuctional organizational units within Carolina Power and Light Company.

f. Reports and meeting minutes of the PNSC.

FOLLOW-UP ACTION

6.5.3.4 Results of Corporate Nuclear Safety (CNS) reviews, including recommendations and concerns shall be documented.

a. Copies of the documented review shall be retained in the Corporate Nuclear Safety and Quality Assurance Audit Section files.

b. Recommendations and concerns shall be submitted to the Vice President - Nuclear Operations within 14 days of determination.

c. A summation of Corporate Nuclear Safety recommendations and concerns shall be submitted to the Chairman/Chief Executive Officer; Senior Executive Vice President and Chief Operating Officer; Executive Vice President - Power Supply and Customer Services; Senior Vice President - Power Supply; Vice President-Nuclear Safety and Research; Plant General Manager; and others, as appropriate on at least a bi-monthly frequency.

6.5.3.5 The Corporate Nuclear Safety Unit review program shall be conducted in accordance with written, approved procedures.

6.5.4 OPERATION AND MAINTENANCE UNIT (OMU)

FUNCTION

6.5.4.1 The Operation and Maintenance Unit of the Corporate Nuclear Safety and Quality Assurance Audit Section shall perform audits of plant activities. These audits shall encompass:

a. The conformance of facility operation to all provisions contained within the Technical Specifications and applicable license conditions at least once per 12 months.

b. The training and qualifications of the entire facility staff at least once per 12 months.

c. The results of actions taken to correct deficiencies occurring in facility equipment, structures, systems, or method of operation that affect nuclear safety at least once per 6 months.

d. The verification of compliance and implementation of the requirements of the Quality Assurance Program to meet the criteria of Appendix "B", 10 CFR 50, at least once per 24 months.

e. The Emergency Plan and implementing procedures at least once per 24 months.

f. The Security Plan and implementing procedures at least once per 24 months.

g. The Facility Fire Protection Program and implementing procedures at least once per 24 months.

h. Any other area of facility operation considered appropriate by the Corporate Quality Assurance Audit Operation and Maintenance Unit, the Executive Vice President - Power Supply and Customer Service, or the Senior Vice President - Power Supply.

PERSONNEL

6.5.4.2

a. Audit personnel shall be independent of the area audited. Selection for auditing assignments is based on experience or training which establishes that their qualifications are commensurate with the complexity or special nature of the activities to be audited. In selecting auditing personnel, consideration shall be given to special abilities, specialized technical training, prior pertinent experience, personal characteristics, and education.

b. Qualified outside consultants or other individuals independent from those personnel directly involved in plant operation, but within the Operations Group, shall be used to augment the audit teams when necessary.

REPORTS

6.5.4.3 Results of audit are approved by the Manager - Corporate Nuclear Safety and Quality Assurance Audit Section and transmitted directly to the Company President/Chief Executive Officer, the Senior Executive Vice President and Chief Operating Officer, the Executive Vice President - Power Supply and Customer Services, the Senior Vice President - Power Supply, and the Vice President - Nuclear Safety and Research, and others, as appropriate within 30 days after the completion of the audit.

6.5.4.4 The Corporate Quality Assurance Audit Program shall be conducted in accordance with written, approved procedures.

6.5.5 OUTSIDE AGENCY INSPECTION AND AUDIT PROGRAM

6.5.5.1 An independent fire protection and loss prevention program inspection and audit shall be performed at least once per 12 months utilizing an outside fire protection firm.

6.5.5.2 An inspection and audit of the fire protection and loss prevention program shall be performed by a qualified outside fire consultant at least once per 36 months.

6.6 REPORTABLE OCCURRENCE ACTION

6.6.1 The following actions shall be taken for REPORTABLE OCCURRENCES:

a. The Commission shall be notified and/or a report submitted pursuant to the requirements of Specification 6.9.

b. Each REPORTABLE OCCURRENCE requiring 24 hour notification to the Commission shall be reviewed by the PNSC and submitted to Manager - Corporate Nuclear Safety and Quality Assurance Audit and the Vice President - Nuclear Operations.

6.7 SAFETY LIMIT VIOLATION

6.7.1 The following actions shall be taken in the event a Safety Limit is violated:

a. The facility shall be placed in at least HOT SHUTDOWN within two hours.

b. The Safety Limit violation shall be reported to the Commission, the Vice President - Nuclear Operations and to the Manager - Corporate Nuclear Safety and Quality Assurance Audit within 24 hours.

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

d. The Safety Limit Violation Report shall be submitted to the Commission, the Manager - Corporate Nuclear Safety and Quality Assurance Audit and the Vice President - Nuclear Operations within 14 days of the violation.

6.8 PROCEDURES

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

a. The applicable procedures recommended in Appendix "A" of Regulatory Guide 1.33, November, 1972.

b. Refueling operations.

c. Surveillance and test activities of safety related equipment.

d. Security Plan implementation.

e. Emergency Plan implementation.

f. Fire Protection Program implementation.

PROCEDURES (Continued)

6.8.2 Each procedure of 6.8.1 above, and changes thereto, shall be reviewed by the PNSC and approved by the General Manager prior to implementation and reviewed periodically by the PNSC as set forth in administrative procedures.

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

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

b. The change is approved by two members of the plant management staff, at least one of whom holds a Senior Reactor Operator's License on the Brunswick Plant.

c. The change is documented, reviewed by the PNSC and approved by the General Manager within 14 days of implementation.

6.9 REPORTING REQUIREMENTS

ROUTINE REPORTS AND REPORTABLE OCCURRENCES

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

STARTUP REPORT

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

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

6.1.1.3 Startup reports shall be submitted within (1) 90 days following completion of the startup test program, (2) 90 days following resumption or commencement of commercial power operation, or (3) 9 months following initial criticality, whichever is earliest. If the Startup Report does not cover all three events (i.e., initial criticality, STARTUP REPORT (Continued)

completion of startup test program, and resumption or commencement of commercial power operation), supplementary reports shall be submitted at least every three months until all three events have been completed.

ANNUAL REPORTS[1/]

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

6.9.1.5 Reports required on an annual basis shall include a tabulation of the number of station, utility and other personnel (including contractors) receiving exposures greater than 100 mrem/yr and their associated man rem exposure according to work and job functions,[2/] e.g., reactor operations and surveillance, inservice inspection, routine maintenance, special maintenance (describe maintenance), waste processing, and refueling. The dose assignment to various duty functions may be estimates based on pocket dosimeter, TLD, or film badge measurements. Small exposures totalling less than 20% of the individual total dose need not be accounted for. In the aggregate, at least 80% of the total whole body dose received from external sources shall be assigned to specific major work functions.

MONTHLY OPERATING REPORT

6.9.1.6 Routine reports of operating statistics and shutdown experience shall be submitted on a monthly basis to the Office of Inspection and Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555, with a copy to the Regional Office, to arrive no later than the tenth of each month following the calendar month covered by the report.

REPORTABLE OCCURRENCES

6.9.1.7 The REPORTABLE OCCURRENCES of Specifications 6.9.1.8 and 6.9.1.9 below, including corrective actions and measures to prevent recurrence, shall be reported to the NRC. Supplemental reports may be required to fully describe final resolution of occurrence. In case of corrected or supplemental reports, a licensee event report shall be completed and reference shall be made to the original report date.

1/ A single submittal may be made for a multiple unit station. The submittal should combine those sections that are common to all units at the station.

2/ This tabulation supplements the requirements of §20.407 of 10 CFR Part 20.

SPECIAL REPORTS

6.9.2 Special reports shall be submitted to the Director of the Office of Inspection and Enforcement Regional Office within the time period specified for each report. These reports shall be submitted covering the activities identified below pursuant to the requirements of the applicable reference specification:

a. Inoperable Seismic Monitoring Instrumentation, Specification 3.3.5.1.

b. Seismic event analysis, Specification 4.3.5.1.2.

c. Reactor coolant specific activity analysis, Specification 3.4.5.

d. Fire detection instrumentation, Specification 3.3.5.7.

e. Fire suppression systems, Specifications 3.7.7.1, 3.7.7.2, and 3.7.7.3.

f. ECCS actuation, Specifications 3.5.3.1 and 3.5.3.2.

6.10 RECORD RETENTION

Facility records shall be retained in accordance with ANSI-N45.2.9-1974.

6.10.1 The following records shall be retained for at least five years:

a. Records and logs of facility operation covering time interval at each power level.

b. Records and logs of principal maintenance activities, inspections, repair and replacement of principal items of equipment related to nuclear safety.

c. All REPORTABLE OCCURRENCE submitted to the Commission.

d. Records of surveillance activities, inspections and calibrations required by these Technical Specifications.

e. Records of changes made to Operating Procedures.

f. Records of radioactive shipments.

g. Records of sealed source and fission detectors leak tests and results.

h. Records of annual physical inventory of all sealed source material of record.

RECORD RETENTION (Continued)

6.10.2 The following records shall be retained for the duration of the Facility Operating License:

a. Records and drawing changes reflecting facility design modifications made to systems and equipment described in the Final Safety Analysis Report.

b. Records of new and irradiated fuel inventory, fuel transfers and assembly burnup histories.

c. Records of facility radiation and contamination surveys.

d. Records or radiation exposure for all individuals entering radiation control areas.

e. Records of gaseous and liquid radioactive material released to the environs.

f. Records of transient or operational cycles for those facility components identified in Table 5.7.1-1.

g. Records of reactor tests and experiments.

h. Records of training and qualification for current members of the plant staff.

i. Records of in-service inspections performed pursuant to these Technical Specifications.

j. Records of Quality Assurance activities required by the QA Manual.

k. Records of reviews performed for changes made to procedures or equipment or reviews of tests and experiments pursuant to 10 CFR 50.59.

l. Records of meetings of the PNSC and of the previous off-site review organization, the Company Nuclear Safety Committee (CNSC).

6.11 RADIATION PROTECTION PROGRAM

Procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR Part 20 and shall be approved, maintained and adhered to for all operations involving personnel radiation exposure.

Objective

This section describes the administrative controls and procedures necessary to implement the Environmental Technical Specifications.

5.1 ORGANIZATION AND REVIEW

The Plant Manager is directly responsible for the safe operation of the facility as shown in Figure 5.1-1. In all matters pertaining to the operation of the plant and to the Environmental Technical Specifications, the Plant Manager is directly responsible to the Manager of Nuclear Generation. The Environmental and Radiation Control Supervisor is directly responsible to the Plant Manager for all Environmental Technical Specifications applicable to the plant, radiological and otherwise. In the Generation Department, the Manager - Generation Services, Harris Energy & Environmental Center Section, and his staff function in a staff capacity to assist in the proper implementation of the Environmental Technical Specifications.

Review of plant operations and the technical specifications shall be accomplished by the Plant Nuclear Safety Committee (PNSC) and the Corporate Nuclear Safety (CNS) Unit as organizationally described in Appendix A to the facility operating license. Independent off-site QA audits of plant operations shall be performed by the Operation & Maintenance (O&M) Unit as described in Appendix A to the facility operating license.

Review and audit functions are defined as follows:

a. Review by PNSC and CNS of proposed changes to the Environmental Technical Specifications and the evaluated impact of the change.

b. Review by PNSC and CNS of changes or modifications to plant systems or equipment which are determined by the Plant Manager to have a significant adverse effect on the environment and the evaluated impact of the change

c. Review by PNSC and CNS of written procedures and changes thereto as described in Section 5.3.2 which are determined by the Plant Manager to detrimentally affect the plant's environmental impact.

d. Investigation by the PNSC of reported instances where an environmental protection limit is exceeded or the occurrence of an unusual environmental event associated with operation of the plant which involves a significant environmental impact. The report and recommendations that result from the PNSC investigation will be reviewed by the CNS.

e. Corporate quality assurance audit of plant operations and written procedures for implementation of these Technical Specifications by O&M.

5.2 ACTION TO BE TAKEN IN THE EVENT OF AN ENVIRONMENTAL EVENT DURING PLANT OPERATIONS

5.2.1 An environmental event shall be reported promptly to the Manager of Nuclear Generation and reviewed by the Plant Nuclear Safety Committee. The Plant Manager shall take action to abate any impact, immediately following his determination of appropriate action permitted by the technical specifications.

5.2.2 As specified in Section 5.4.2, a report of each environmental event shall be reviewed by the Plant Nuclear Safety Committee. This report shall include an evaluation of the cause of the event, a record of the corrective action taken, and the recommendations for appropriate action to prevent or reduce the probability of a recurrence.

5.2.3 Copies of all such reports shall be submitted to the Manager of Nuclear Generation and the Manager of Corporate Nuclear Safety and Quality Assurance Audit Section for review.

5.2.4 The circumstances of any environmental event shall be reported to the NRC as specified in Section 5.4.2.

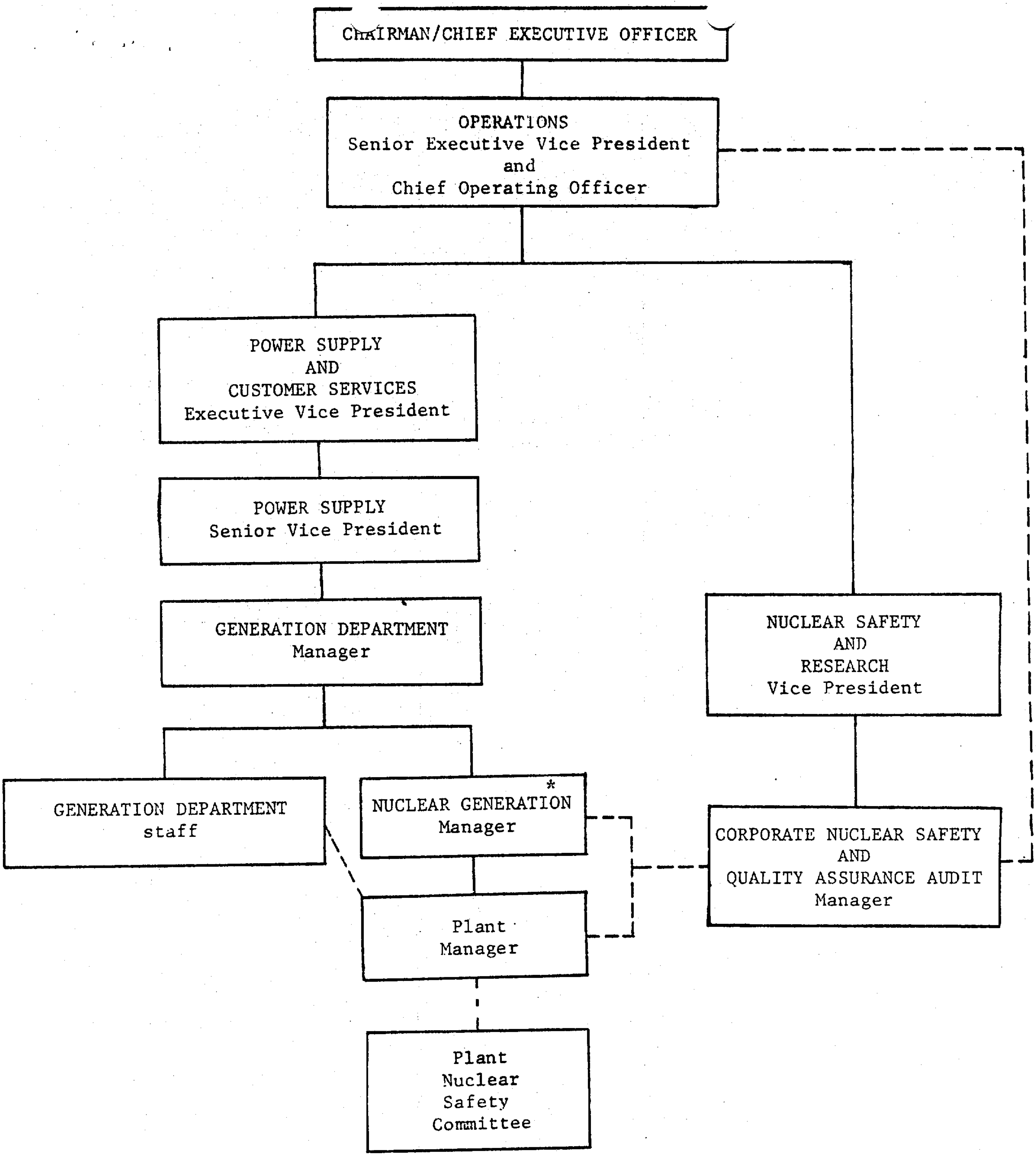
5.3 OPERATING PROCEDURES

5.3.1 Written procedures shall be prepared and approved as specified in Section 5.3.2 for operation to ensure compliance with the environmental protection conditions and associated surveillance requirements of Sections 2 and 3. Procedures will include sampling, analysis, and actions to be taken when environmental protection conditions are exceeded. Quality assurance procedures will be developed for monitoring, sample collection, and sample analysis. Testing frequency of any alarms will also be included.

5.3.2 Procedures described in Section 5.3.1 above, and changes thereto, determined by the Plant Manager to detrimentally affect the plant's environmental impact, shall be reviewed as specified in Section 5.1 and approved by the Plant Manager prior to implementation. Temporary changes to procedures which do not change the intent of the original procedure may be made, provided such changes are approved by two members of the plant management staff. Such changes shall be documented, and subsequently reviewed by the Plant Nuclear Safety Committee and approved by the Plant Manager prior to implementation as permanent procedure changes.

5.3.3 Procedures described in Section 5.3.1 above, and changes thereto, which are determined by the Plant Manager to not detrimentally affect the plant's environmental impact shall be reviewed and approved by the Plant Manager or other member of the plant management staff designated by the Plant Manager prior to implementation.

5.3.4 Written procedures shall be prepared and approved



*Responsible for performance and monitoring of Fire Protection Program.

MANAGEMENT ORGANIZATION CHART
Figure 5.1-1

Effective date: Sept. 1, 1979
Amendment No. 51

Analyses of environmental samples which exceed the larger of either the control station value (Table 4.2-5) or the minimum detection limit by a factor of 10 or more for that same sample type and time period will be identified and if determined to be attributable to the operation of the Brunswick Plant, a written report shall be submitted to Director of the appropriate regional office (copy to the Director of Nuclear Reactor Regulation) within 30 days after confirmation.* The test for exceeding the guide value will be a T test at 99.5% confidence. The test will be considered positive when:

$$X_i - (X_c \; 10) > T_{99.5\%} \sqrt{\sigma_i^2 + \sigma_c^2} \; (100)$$

where:

$T_{99.5\%}$ = 1 tail T test (2.2414)

X_i = value obtained at station i

X_c = either value obtained at control station or minimum detection limit (mdl), whichever is larger.

σ_i = standard deviation of station i value

σ_c = standard deviation of control station

*A confirmatory reanalysis of the original, a duplicate or a new sample may be desirable, as appropriate. The results of the confirmatory analysis shall be completed at the earliest time consistent with the analysis, but in any case within 30 days. If the high value is real, the report to the NRC shall be submitted.

If milk samples collected over a calendar quarter show average I-131 concentrations of 4.8 picocuries per liter or greater and the increase is determined to be attributable to the operation of the Brunswick Plant, a written report shall be submitted to the Director of the appropriate regional office (copy to the Director of Nuclear Reactor Regulation) within 30 days, and should include an evaluation of any release conditions, environmental factors, or other aspects necessary to explain the anomalous results.

c. Miscellaneous Reports

(1) When a change to the plant design, to the plant operation, or to the procedures described in Section 5.3 is planned which would have a significant adverse effect on the environment as determined by the Plant Manager or which involves a significant environmental matter or question not previously reviewed and evaluated by the NRC, a report on the change shall be submitted to the NRC for information prior to implementation. The report shall include description and evaluation of the impact of the change.

(2) Request for changes in Environmental Technical Specifications shall be submitted to the Director of Nuclear Reactor Regulation, NRC, for prior review and authorization. The request shall include an evaluation of the impact of the change.

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

SUPPORTING AMENDMENT NO. 28 TO FACILITY LICENSE NO. DPR-71 AND AMENDMENT NO. 51 TO FACILITY LICENSE NO. DPR-62

CAROLINA POWER & LIGHT COMPANY

BRUNSWICK STEAM ELECTRIC PLANT UNIT NOS. 1 AND 2

DOCKET NOS. 50-325 AND 50-324

A. Brunswick Steam Electric Plant, Unit No. 2, Fuel Cycle 4 - Reload Application

By letter dated February 20, 1980, as supplemented April 11, 1980, Carolina Power and Light Company (the licensee or CP&L), requested amendments to Facility Operating License No. DPR-62. The proposed changes relate to the replacement of 132 fuel assemblies constituting refueling of the core for fourth cycle operation at power levels up to 2436 Mwt (100% power) for Brunswick Steam Electric Plant Unit No. 2 (BSEP2).

CP&L had requested credit for the end-of-cycle recirculation pump trip (EOC-RPT) feature in the previous Cycle 3 reload proposal. As indicated in the Safety Evaluation for Amendment 48 to DPR-62 dated May 2, 1979, the staff had reservations about the design implementation of the EOC-RPT system. Our concerns were associated with verivication testing and electrical design interfaces. By letter dated May 21, 1980, the licensee provided information on the BSEP2 EOC-RPT verification testing. The EOC-RPT electrical design interface is discussed in section C of this SER.

Corrective Action for Reload MCPR Error

By letter dated April 23, 1980, the licensee provided a summary of corrective action taken to avoid recurrence of an error that occurred during licensing of the previous SEP Unit 2 reload. The error involved incorrect computer input data that resulted in non-conservative minimum critical power ration (MCPR) limits for the latter part of the operating cycle. It appears that the corrective action taken will be adequate to preclude similar errors in future reload proposals.

The staff was assisted in the Safety Evaluation of the Brunswick 2 Reload-3 licensing analysis by our technical consultant, Brookhaven National Laboratory (BNL). The following evaluation was submitted by BNL on May 27, 1980.

SAFETY EVALUATION OF BRUNSWICK 2
RELOAD-3 LICENSING ANALYSIS

1. INTRODUCTION

A safety evaluation has been carried out for Carolina Power and Light Company's Brunswick Steam Electric Plant Unit 2 Reload 3 (BSEP-2 R-3). This plant is a BWR-4 which contains 560 fuel assemblies. The Reload 3, or Cycle 4 core is expected to include 132 fresh P8 x 8R type assemblies, approximately 24% of the core.

In support of its application for a reload license to operate the BSEP-2 R-3, Carolina Power and Light (CP&L) has submitted along with a letter to the NRC[1], a proposed set of revisions to the Technical Specifications as well as the Supplemental Reload Licensing Submittal[2] which includes credit for the end-of-cycle recirculation pump trip (EOC-RPT) system. This supplemental submittal is also referred to as the RPT-analysis submittal. In a subsequent transmittal to the NRC[3] CP&L submitted a new set of revisions to the Technical Specifications and a revised version of the Supplemental Reload Licensing Submittal.[4] The revisions to the technical specifications refer to operation with the RPT system whereas the revised Supplemental Submittal[4] does not include credit in thermal margins for the EOC-RPT. MCPR limits in the non-RPT analysis are more restrictive. These more restrictive Operating Limit MCPR's (OLMCPR) are to be observed if the EOC-RPT system becomes inoperable. Reference 4 is also known as the non-RPT analysis submittal.

With the exception of the sections of this document where MCPR limits and EOC-RPT are discussed, the evaluation applies to both RPT and non-RPT cases.

Reference 5 provides values for plant-specific data, such as steady state operating pressure, core flow, safety and safety-relief value setpoints and other design parameters. Additional plant and cycle specific data are provided in the Supplemental Reload Transmittals[2,4]. These latter documents follow the outline presented in Appendix A of Reference 5. The Licensee has agreed to supply the Commission with comparisons of measured to calculated pump coastdown data, which will provide the basis for our consideration of the RPT feature. Our acceptance of the analysis for the RPT operation depends on the favorable outcome of that comparison.

Our evaluation of the Brunswick 2 Reload 3 is limited to the items discussed in the following sections.

2. EVALUATION

2.1 Nuclear Characteristics

The 132 fresh P8 x 8R assemblies are designated as P8DRB265H. The Cycle 4 core will have 428 previously exposed Reload 1 and 2 8 x 8 and 7 x 7 assemblies, including 152 bundles from the initial core. The breakdown of these bundle types is listed in Reference 2. Results of calculations presented in Section 4 of Reference 2 show that throughout the cycle both the control rod system and the standby liquid control system will have adequate shutdown capability under the most reactive conditions of the core.

2.2 Thermal Hydraulics

2.2.1 Fuel Cladding Integrity Safety Limit MCPR

According to Reference 5, the safety limit MCPR (SLMCPR) for BWR-4 cores which refuel with 8 x 8R and P8 x 8R is 1.07. This limit implies that during a transient characterized by an MCPR of 1.07, 99.9% of the fuel rods in the core are expected to avoid boiling transition. We note that the use of prepressurized fuel rods in the 132 fresh bundles planned for loading in the Cycle 4 core will have the effect of slightly reducing fuel temperatures during power operation. This effect will result in a small reduction in the local Doppler feedback effect on pin power peaking. The resulting difference in the local peaking between 8 x 8R and P8 x 8R assemblies is reported to be insignificant (References 6 and 7). Furthermore, higher peaking in the prepressurized (P8 x 8R) retrofit assemblies would tend to reduce the flatness of intrabundle peaking and since decreased peaking (flatter power distribution) results in more rods in boiling transition in the GETAB analysis, the use of the 8 x 8R R-factor distribution for P8 x 8R reloads is considered conservative. The staff has found this approach in arriving at the statistical safety limit, originally derived for 8 x 8R BWR reloads, to be equally acceptable for the P8 x 8R reloads. (Reference 9)

2.2.2 Operating Limit MCPR

To establish the OLMCPR for the Brunswick 2 Cycle 4 operation, two separate transient analyses were performed with the REDY code: (a) for operation with the RPT system[2], and (b) for operation without the RPT system.[4] As mentioned earlier, OLMCPR's for the RPT operation are less restrictive. Operating limit MCPR's for each type of fuel in the Cycle 4 core are given in Reference 2 for the RPT operation. Additional confirmatory analyses have been performed with the ODYN code for this case. For operation without the RPT, thermal margins are reduced. OLMCPR's for non-RPT operation are given in Reference 4.

Operating MCPR limits for the non-RPT case are found acceptable. However, for the RPT operation, the OLMPCPR for the 8 x 8R fuel must reflect the penalty associated with the use of the ODYN code as discussed in Section 2.2.2.1 and in accordance with Reference 9. The new initial CPR ($ICPR_{new}$) is obtained as follows:

STEP 1. ODYN-Calculated ΔCPR: $\Delta CPR_c = 0.14$

STEP 2. Calculated ICPR; $ICPR_c = 1.07 + 0.14 = 1.21$

where the GETAB limit is 1.07

$$\frac{\Delta CPR_c}{ICPR_c} = \frac{0.14}{1.21} = 0.116$$

STEP 3.

$$\frac{\Delta CPR_{new}}{ICPR_{new}} = 0.116 + 0.044 = 0.160$$

Since $ICPR_{new} - \Delta CPR_{new} = 1.07$

or $(1.00 - 0.16)\ ICPR_{new} == 1.07$

$ICPR_{new} = 1.27$

Hence, the new initial OLMCPR for the 8 x 8R fuel is 1.27.

2.2.2.1 Transient Analysis Methods

The generic methods used for these calculations, including cycle-independent initial conditions and transient input parameters, are described in Reference 5. The staff evaluation, included as Appendix C of Reference 5, contains the acceptance of the cycle-independent values. The evaluation of the transient analysis methods, appears in Appendix C of Reference 3. Supplementary cycle-independent initial conditions and transient input parameters used in the transient analyses for both RPT and non-RPT cases appear in the tables in Sections 6 and 7 of References 2 and 4. The evaluation of the methods used to develop these supplementary input values is also included in Reference 10.

For plants which utilize the RPT system, additional analysis or justification has been required, since it has been concluded that the current methods do not adequately model the RPT phenomena. Therefore, the licensee has presented an ODYN transient analysis with RPT. ODYN is an improved transient analysis code which has been used in the past to model RPT phenomena (TVA Reference 8). However, due to uncertainties in the ODYN code, a penalty of 0.044 in (CPR/ICPR) must be applied to the licensing calculations, as described in Reference 9.

2.2.2.2 Transient Analysis Results

The transients evaluated were the limiting pressurization and power increase transients (generator load rejection without bypass, the feedwater controller failure and loss of feedwater heating), and the control rod withdrawal error. The analysis results of the fuel loading error have been incorporated in the specification of the operating limit MCPR per Reference 5 (see Section 2.3.3). Initial conditions and transient input parameters as specified in Sections 6 and 7 of both References 2 and 4 were assumed.

The results of these analyses are outlined in Sections 9 and 10 of both References 2 and 4. It is acceptable if fuel specific operating limits are established for prepressurized fuel (Reference 10). On this basis, the transient analysis results are acceptable for use in the evaluation of the operating limit MCPR.

2.3 Accident Analysis

2.3.1 ECCS Appendix K Analysis

In the safety evaluation of Reference 5, it was concluded that "the continued application of the present GE ECCS-LOCA ("Appendix K") models to the 8 x 8 retrofit reload fuel is generically acceptable" and in the Reference 10 evaluation that conclusion was extended to prepressurized fuel. On these bases, the proposed MAPLHGR limits for the new prepressurized fuel are acceptable.

2.3.2 Control Rod Drop Accident

The significant parameters in the rod drop analysis satisfy the requirements for the bounding analyses described in Reference 5. Therefore, the results of this analysis are well below the acceptance criterion of 280 calories per gram.

2.3.3 Fuel Loading Error

The GE method for analysis of misoriented and misloaded bundles has been reviewed and approved by the staff and is part of the Reference 5 methodology. Potential fuel loading errors involving misoriented bundles and bundles loaded into incorrect positions have been analyzed by this methodology and the results have been incorporated into the specification for operating limit MCPR. This assures that SLMCPR is not violated for any potential error in either orientation or loading of a bundle.

2.3.4 Overpressure Analysis

The overpressure analysis for the MSIV closure with high flux scram, which is the limiting overpressure event, has been performed in accordance with the requirements of Reference 10. We agree that there is sufficient margin between the peak calculated vessel pressure and the design limit pressure. Therefore, the limiting overpressure event as analyzed by the licensee is considered acceptable.

2.5 Technical Specifications

The Technical Specifications have been changed to include specifications associated with the new, prepressurized type bundles. Reference 10 contains the revised limiting conditions for operation as well as the corresponding surveillance requirements, regarding the Average Planar Linear Heat Generation Rates (APLHGR's), the APRM and Rod Block Monitor setpoints, and Linear Heat Generation Rates (LHGR's) applicable to the Reload 3 core operation for the RPT case. Technical Specifications for OLMCPR's for the RPT operation must be consistent with the values established in this evaluation for the 8 x 8R fuel. Technical Specifications changes reflecting limiting conditions for operation and surveillance requirements as well as OLMCPR's resulting from the introduction of the new type of bundles for the non-RPT case have been reviewed and found acceptable.

2.6 Densification Power Spiking

It is acceptable[11] to remove the 8 x 8, 8 x 8R and P8 x 8R spiking penalty factor from the Technical Specification of those BWR's for which it can be demonstrated that the predicted worst case maximum transient LHGR's, when augmented by the power spike penalty, do not violate the exposure-dependent safety limit LHGR's. The Brunswick 2 plant meets the above criterion. Section 10, Rod Withdrawal Error and Appendix E Linear Heat Generation Rate for Bundle Loading Error, of Reference 2 and 4 include the densification effect in the reported LHGR value for all 8 x 8 type assemblies. On the basis of these data, we find that the licensee meets the requirements on the densification power spiking.

2.7 Recirculation Pump Trip Feature

In Appendix C of Reference 2, a qualitative description of the Recirculation Pump Trip (RPT) feature is given. The purpose of the RPT system is to mitigate core-wide pressurization transients by a rapid reduction in core flow and an increase in the core void content thereby reducing the peak transient power and heat flux. The proposed Technical Specifications indicate that the RPT system shall be demonstrated operable on a monthly basis. In evaluating the OLMCPR's for the RPT operation, it has been assumed that the RPT system is operable. Questions related to the hardware and reliability of the RPT system are outside the scope of this review and therefore are not being addressed in this work.

Our acceptance of the analysis for the RPT operation is based on the receipt of the additional information, agreed to by CP&L, leading to favorable comparison between measured and assumed pump coastdown data.

REFERENCES

1. Letter, E. E. Utley (Carolina Power and Light Company) to T. A. Ippolito (USNRC) February 20, 1980.

2. J. L. Rash, "Supplemental Reload Licensing Submittal for Brunswick Steam Electric Plant Unit 2 Reload 3," NEDO-24235, General Electric Company, January, 1980.

3. Letter, E. E. Utley (Carolina Power and Light Company) to T. A. Ippolito (USNRC), April 11, 1980.

4. J. L. Rash, "Supplemental Reload Licensing Submittal for Brunswick Steam Electric Plant Unit 2 Reload 3, NEDO-24235 Revision 1, General Electric Company, March 1980.

5. "General Electric Boiling Water Reactor Generic Reload Application," NEDE-24011-P-A, August, 1979.

6. General Electric letter (E. Fuller) to USNRC (O. Parr), June 8, 1978.

7. General Electric letter (E. Fuller) to USNRC (O. Parr), August 14, 1978.

8. Letter, T. A. Ippolito (USNRC) to H. G. Parris (TVA) dated February 8, 1979 and enclosed SER.

9. Letter, R. P. Denise (USNRC) to G. G. Sherwood (GE) and enclosure, dated January 23, 1980.

10. Letter, T. A. Ippolito (USNRC) to R. Gridley (G.E.), April 16, 1979 and enclosed Safety Evaluation Report.

11. Revised Technical Specifications for Carolina Power and Light Brunswick Steam Electric Plant Unit 2. (Attached to Reference 1)

3.0 Conclusions

Based on our review of the consultant's Safety Evaluation and our own examination of the recirculation pump coast-down characteristics provided by CP&L in their letter dated May 21, 1980, we find the proposed operation in Cycle 4 allowing credit for EOC-RPT to be acceptable. The May 21, 1980 letter also committed to perform the same series of physics tests that were judged acceptable during the previous refueling. We find this startup test program acceptable for Cycle 4 operation. As indicated in the BNL evaluation, the Technical Specification Operating Limit MCPR for 8x8R and P 8x8R fuel has been revised to include the required ODYN penalty for EOC-RPT operation.

B. Brunswick Steam Electric Plant, Unit Nos. 1 and 2 Degraded Grid Voltage Protection

1.0 INTRODUCTION

In response to the NRC's generic letter of June 3, 1977, CP&L proposed design modifications and changes to the Technical Specifications in accordance with the criteria and staff positions contained in our letter.

2.0 MODIFICATIONS

The following modifications were proposed in response to the generic letter of June 3, 1977:

a) Installing second level undervoltage relays, three on each of the four 4160v Class 1E bus with a drop out setting at 89.5% of nominal bus voltage and a 10 second time delay in coincident trip logic (2 out of 3) for degraded grid voltage protection.

b) Blocking the load shedding feature on the 4160v Class 1E buses when the diesel generators are supplying to these buses, and automatically reinstating this feature when the diesel generator breakers are tripped.

3.0 EVALUATION

The acceptability of the BSEP Units 1 & 2 Degraded Grid Voltage Protection modifications was reviewed for the staff by our technical consultant, EG&G Idaho, as part of the Selected Electrical, Instrumentation, and Control Systems Issues Program. The basis for acceptance is documented in "Technical Evaluation Report of the Degraded Grid Protection for Class 1E Power Systems at the Brunswick Steam Electric Plant, Unit Nos. 1 and 2" dated February 1980 which is incorporated herein by reference.

4.0 CONCLUSIONS

Based on our review of the referenced consultant's Technical Evaluation Report, we agree with their findings that the modifications will protect the safety related equipment from a sustained degraded voltage of the offsite power source and the design bases meet the Staff's Positions. Also, we agree with the consultant that the proposed changes to the Technical Specifications adequately address testing of the protection systems and comply with Staff Position 3.

Therefore, we conclude that CP&L's proposed design modifications and changes to the Technical Specifications are acceptable.

C. Brunswick Steam Electric Plant, Units 1 and 2 End-of-Cycle Recirculation Pump Trip

1.0 INTRODUCTION

By letter dated February 2, 1979, as supplemented March 21, 1979, April 13, 1979, April 27, 1979, May 1, 1979, May 29, 1979, February 5, 1980, and April 11, 1980, the licensee provided information regarding the prompt recirculation pump trip feature. The letters dated April 13, 1979, April 27, 1979, and April 11, 1980 proposed Technical Specifications for the EOC-RPT.

2.0 DISCUSSION

The design philosophy for the EOC-RPT system is described in General Electric's (GE) report NEDO-24119 "Basis for Installation of Recirculation Pump Trip System," Browns Ferry Nuclear Plant, April 1978. The application of the EOC-RPT to Brunswick Unit 2 was described in GE report NEDO-24587, SUPPLEMENTAL RELOAD LICENSING SUBMITTAL FOR BRUNSWICK STEAM ELECTRIC PLANT UNIT 2 RELOAD 2 (RECIRCULATION PUMP TRIP FEATURE) dated January 1979 and GE report NEDO-24179 Revision 1 (same title) dated March, 1979.

3.0 EVALUATION

The acceptability of the BSEP 2 EOC-RPT feature was reviewed for the staff by our technical consultant, Lawrence Livermore Laboratory, as part of the Selected Electrical, Instrumentation, and Control Systems Issues Program. The basis for acceptance is documented in "Technical Evaluation of the End-of-Cycle Recirculation Pump Trip for Brunswick Steam Electric Plant Unit No. 2" dated April 1980 which is incorporated herein by reference.

4.0 CONCLUSIONS

Based on our review of the referenced consultant's Technical Evaluation Report, we conclude that the EOC-RPT feature for the BSEP meets applicable design criteria. We find the proposed design acceptable for both units 1 and 2. The proposed Technical Specification changes for BSEP Unit 2 to incorporate the EOC-RPT feature are acceptable, as modified by discussions with the staff. We have determined through discussions with the licensee, as documented in their submittal dated May 21, 1980, that the BSEP Unit 2 EOC-RPT system response time is less than the response time assumed in the transient analysis for the BSEP Unit 2 reload application. A similar verification will take place prior to authorizing credit for EOC-RPT for BSEP Unit 1. We, therefore, find the EOC-RPT feature acceptable.

D. Brunswick Steam Electric Plant, Unit Nos. 1 and 2 Reactor Vessel Water Level Instrumentation

1.0 INTRODUCTION

By letter dated January 18, 1979, the licensee requested revisions to the Technical Specifications for BSEP Units 1 and 2 concerning operability requirements for reactor vessel water level low and low-low instrumentation. These changes were requested to allow the performance of maintenance and modification work on the reactor vessel and ancillary systems during cold shutdown and refueling.

2.0 DISCUSSION

The Commission issued Amendment No. 18 to Facility License No. DPR-71 for BSEP Unit No. 1 on January 19, 1979 which granted a one-time Special Test Exception to allow lowering the reactor vessel water level for extended maintenance during the then current refueling outage. The staff indicated that prior to authorizing a permanent change to the Technical Specifications providing this flexibility, further review would be required to judge the acceptability of this change on a generic basis. Of specific concern was the possibility for inadvertently draining the reactor vessel.

3.0 EVALUATION

The staff's continuing review revealed no creditible mechanism for draining the reactor vessel inadvertently while in modes 4 or 5. In particular, there were no events which could be postulated that would overpressurize or rupture low pressure piping systems and lead to draining the vessel. Even considering a non-mechanistic failure resulting in loss of vessel inventory, a level decrease (to L3) will automatically initiate LPCI to maintain vessel inventory, since the low-low-low level instruments are not affected by this change. Furthermore, water level is required to be monitored periodically during refueling. As a result of this determination, the GE Standard Technical Specifications were revised to remove the low and low-low water level instrumentation operability requirements with cold shutdown or refueling conditions in effect.

4.0 CONCLUSION

We conclude that there is no safety related function for low and low-low reactor vessel water level instrumentation in operational conditions 4 or 5. Revising the BSEP Technical Specifications to be consistent with the now current GE Standard Technical Specifications is an acceptable alternative to providing a Special Test Exception, as was originally requested. This modification has been discussed and agreed with by the licensee.

E. Brunswick Steam Electric Plant, Unit Nos. 1 and 2 Corporate Organizational Changes

1.0 INTRODUCTION

By letter dated November 7, 1979, the licensee requested a revision to the Technical Specifications for BSEP Units 1 and 2. The changes would reflect administrative corporate organizational changes which became effective on November 3, 1979.

2.0 DISCUSSION

The licensee had proposed a corporate reorganization on August 14, 1979. The November 7, 1979 submittal superceded the previous submittal which had not been reviewed by the staff.

3.0 EVALUATION

The proposed changes were found to be acceptable. However, our review identified the lack of specific provisions to formalize the requirement that the Corporate Nuclear Safety & Quality Assurance Audit Section review records of the Plant Nuclear Safety Committee activities. During telephone discussions on this subject, the licensee agreed to accept our proposed Technical Specifications for this requirement.

4.0 CONCLUSION

Based on our review of the licensee's submittal and the agreed upon corrective action for the one identified discrepancy, we find the proposed change acceptable.

F. Brunswick Steam Electric Plant, Units 1 and 2 RHR Service Water Pump Discharge Pressure

1.0 INTRODUCTION

By letter dated December 31, 1979, the licensee requested a revision to the Technical Specifications for BSEP Units 1 and 2. The changes would revise the operability test requirements for the Residual Heat Removal (RHR) service water pumps.

2.0 DISCUSSION

The licensee reported that an error in the data sheet used in the calibration of the flow instrument during the original startup test resulted in an incorrect discharge pressure requirement in the Technical Specifications. The correct value has been proposed in

terms of differential pressure across the pump with a minimum allowable suction pressure and flow rate. In effect, the minimum discharge pressure has been decreased from 300 psig to 252 psig at 4000 gpm.

3.0 EVALUATION

The importance of the service water pump discharge pressure is an equipment specification which requires that the pumps maintain a minimum differential pressure of 20 psid from the tube to the shell side of the RHR heat exchangers, thereby preventing reactor water leakage into the service water system. Plant procedures permit shutdown cooling initiation at a reactor vessel pressure of 125 psig or below; thus, sufficient service water pressure is available to maintain the heat exchanger differential pressure during the shutdown cooling mode of operation. In the worst case accident condition (steam condensing mode) the shell (reactor) side of the RHR heat exchanger could experience pressures as high as 183 psig. With the tube (service water) side of the heat exchanger maintained at a minimum of 252 psig, sufficient service water pressure is available to maintain the heat exchanger differential pressure during the accident mode of operation.

4.0 CONCLUSION

The proposed change to the residual heat removal service water subsystem operability surveillance requirement is conservative. The change establishes a minimum allowable suction pressure requirement consistent with ASME Section XI, and provides for a more complete characterization of the required pump performance. We find the proposed change acceptable.

G. Brunswick Steam Electric Plant, Unit Nos. 1 and 2 Revision of Environmental Technical Specifications

1.0 INTRODUCTION

By letter dated December 27, 1976, the licensee proposed a change to the Environmental Technical Specifications (ETS) for BSEP Units 1 and 2. The change would modify the reporting requirements to make them more responsive to plant-associated occurrences.

2.0 DISCUSSION

The current reporting requirements for Non-Routine radiological reports (30 day) do not differentiate between increases attributable to the operation of the plant and increases due to other events, such as atmospheric nuclear weapons testing. It is possible to make this distinction using isotopic analysis methods, with a reasonable degree of accuracy, given that the analyst is aware of off-site events and plant occurrences that could be responsible for any identified radionuclides.

3.0 EVALUATION

The licensee is required to provide a separate annual environmental radiological report including survey and sample summaries, and environmental data analyses. Radiological environmental monitoring increases not attributable to plant operation should be reported in the annual report. We concur that it is not appropriate to report radiological environmental monitoring increases determined to be unrelated to plant operation in Non-Routine reports.

4.0 CONCLUSION

We find the proposed ETS change to be acceptable.

H. BSEP Unit No. 2 Hydraulic Snubbers

1.0 INTRODUCTION

By letter dated May 27, 1980, the licensee requested a revision to the listing of safety related hydraulic snubbers for Brunswick Unit 2.

2.0 DESCRIPTION

The proposed revision was the result of a plant modification which identified four (4) hydraulic snubbers that could be replaced with rigid restraints. It is proposed that the following snubbers on reactor vessel instrument lines be removed from Table 3.7.5-1:

2PS-3558
2PS-3561
2PS-3562
2PS-3570

3.0 EVALUATION

The seismic analysis supporting the proposed snubber deletion was performed using methods developed under IE Bulletin 79-07 by CP&L. The analysis techniques were accepted by NRC on October 17, 1979. The revision of Table 3.7.5-1 based on the seismic reanalysis using the approved methods is acceptable.

4.0 CONCLUSION

The proposed revision to Table 3.7.5-1 is approved. Future snubber deletions requiring technical specification changes should be proposed in advance to enable staff concurrence prior to initiating modifications.

I. ENVIRONMENTAL CONSIDERATION

We have determined that the amendments do not authorize a change in effluent types or total amounts nor an increase in power level and will not result in any significant environmental impact. Having made this determination, we have further concluded that the amendments involve an action which is insignificant from the standpoint of environmental impact and pursuant to 10 CFR §51.5(d)(4) that an environmental impact statement, negative declaration, or environmental impact appraisal need not be prepared in connection with the issuance of the amendments.

J. CONCLUSION

We have concluded, based on the considerations discussed above, that: (1) because the amendments do not involve a significant increase in the probability or consequences of accidents previously considered and do not involve a significant decrease in a safety margin, the amendments do not involve a significant hazards consideration, (2) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, and (3) such activities will be conducted in compliance with the Commission's regulations and the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

Dated: June 11, 1980

SUPPLEMENT NO. 2

TO THE

FIRE PROTECTION

SAFETY EVALUATION REPORT

BY THE

OFFICE OF NUCLEAR REACTOR REGULATION

U.S. NUCLEAR REGULATORY COMMISSION

IN THE MATTER OF

CAROLINA POWER & LIGHT COMPANY

BRUNSWICK STEAM ELECTRIC PLANT

UNIT NOS. 1 and 2

DOCKET NOS. 50-325 and 50-324

DATE: June 11, 1980

8006270039

The following evaluation addresses four areas. Item 1.0, Protection of Redundant Safe Shutdown Cabling (greater than five foot separation), was identified as an incomplete item in our fire protection SER supplement of April 6, 1979. Item 2.0, Protection of Redundant Safe Shutdown Cabling (less than five foot separation), addresses a concern identified during our site visit of March 5 and 6, 1980. Item 3.0, Fire Protection Loop Isolation Valve, was identified in an I&E inspection as a deviation. Item 4.0, Door Frames for Fire Doors - Diesel Generator Building, discusses a proposed change to a commitment identified in our fire protection SER.

1.0 <u>Protection of Redundant Safe Shutdown Cabling (greater than five foot separation)</u>

Our SER supplement of April 6, 1979, indicated that the cable study performed by CP&L and United Engineers and Constructors (UE&C) adequately evaluated situations where cabling from redundant safe shutdown divisions were routed within five feet horizontally of each other. However, except for high hazard areas, the study assumed that where cables were separated by more than five feet horizontally, these would not be involved in a single fire. We were concerned that certain situations could exist where a fire could still affect redundant cabling, even if separated by five feet horizontally. Accordingly, our SER supplement of April 6, 1979 noted that this issue was still under review.

On March 5 and 6, 1980, we visited the site to survey those areas where it appeared that safe shutdown cabling came to within 5 to 15 feet of each other. Areas surveyed were the diesel generator building basement, service water structure basement, and general open areas of both reactor buildings. Based on our evaluation of these areas, we find that adequate separation and/or fire protection (sprinklers and barriers) have been provided to assure that fires that could be postulated for these areas will not cause loss of redundant safe shutdown cabling. Accordingly, we find that fire protection for safe shutdown cabling separated by more than five feet horizontally satisfies the objectives identified in Section 2.0 of our SER and is therefore acceptable.

2.0 Protection of Safe Shutdown Cabling (less than five foot separation)

Our SER supplement of April 6, 1979, noted that adequate protective measures had been proposed for redundant safe shutdown cabling that was routed within five feet of each other. These protective measures included use of thermal blankets, 3-hour fire enclosures, sprinkler systems, and cable coatings as required to protect from postulated fires. These measures were documented in the cable study report submitted March 30, 1978 and subsequent correspondence from CP&L of March 15, 1979, and were to be completed during the 1979 refueling outages.

During our site visit of March 5 and 6, 1980, we identified two locations where redundant safe shutdown cabling were routed in close proximity to each other such that a fire in cable trays of one division could cause loss of cables in conduit from the other division. In each of these areas, it appears that the problems were not identified in the cable study referenced above, but apparently should have been. The following discusses the concerns in these two areas:

Intake Structure Basement - At one end of this area, cabling in conduit associated with the green division lube water pump for Unit 1 is routed adjacent to and directly over red division cable trays. Aprinkler heads are located in the area. including below the red division trays; however, no thermal barriers are provided. With the present protection a fire in the red division trays could also damage the green division cabling in conduit prior to actuation of the sprinkler system, or if the sprinkler system fails to operate. The potential for a fire to affect this redundant cabling was not identified in the licensee's cable study; although, with the criteria used in the study, this problem should have been identified. By letter dated April 1, 1980, the licensee has proposed to install 1-1/2 hour fire-rated thermal insulation on the green-division conduit associated with the Unit 1 service water lube pump to protect it from a fire in the red division. cable trays.

Unit 1 Reactor Building - Elevation 20 Feet - In the southwest area at this elevation, cabling associated with the green division is routed vertically within two feet of a horizontal red division cable tray, and then is routed parallel to the red tray for a distance of approximately 25 feet at an elevation of approximately four feet greater than the cable tray. The concern is that a fire in the red tray could damage the green division cable in conduit. No sprinkler or thermal barriers are provided in this location. The green cable is routed to a motor operator associated with the RHR system. This green division motor is located adjacent to a stack of six red division cable trays; because of this, there is also concern that a fire in these trays could affect operability of this valve, as well as loss of the redundant red division RHR system due to cable involved in the fire. As in the intake structure, these problems should have been identified in the original cable study, but were not. By letter of April 1, 1980, the licensee has proposed to install 1 1/2 hour fire-rated thermal insulation on the green division conduit identified above up to the valve operator, and to provide a sprinkler head to protect the motor operator from a fire in the red division cable trays. In addition, the red division cable trays are coated with a fire retardant coating where they are in proximity to the valve operators. With the changes described above, we find that protection provided for these two identified areas of concern satisfy the objectives of Section 2.0 of our SER and is therefore acceptable. We also find the proposed schedule for implementation to be acceptable.

3.0 Fire Protection Loop Isolation Valve

As noted in our SER of February 22, 1977, the licensee had proposed to add additional sectionalizing valves on the yard loop and that the loop would conform with NFPA 24, "Outside Protection." NFPA 24 requires that all control valves in the fire protection water system be indicating type except where required by special conditions, and accepted by the authority having jurisdiction. Part of the fire protection loop runs across the turbine building and has a curb (key operated) valve installed in a covered pit as a sectional control valve. A bypass controlled by normally open post indicator valves is installed around this valve to afford added flexibility in control of the system. This arrangement is acceptable on the basis of: (1) general inaccessability of the valve in the pit with a steel plate cover; (2) the valve being key operated, i.e., a hand wheel is not installed on the valve; and (3) periodic surveillance of valve position by the licensee.

4.0 Door Frames for Fire Doors in Diesel Generator Building

Our SER originally called for all fire door frames to be labeled by a recognized testing laboratory. The licensee has modified a number of frames for fire door installation in the Diesel Generator Building and provided details in a letter dated February 25, 1980, to demonstrate that these modifications make the frames satisfactory for three-hour fire-rated service. We have evaluated details of the modification and visually examined the modifications during a site visit of March 5 and 6, 1980. We find that the fire door frames as modified are satisfactory for the service intended to prevent fire spread through the protected openings in the Diesel Generator Building fire barriers, and are therefore, acceptable.

5.0 Fire Barrier Penetration Technical Specifications

Our letter dated February 14, 1980 requested the licensee to revise the Technical Specifications for fire barrier penetrations at BSEP to conform to the current General Electric standard. Model Technical Specifications were provided as guidance. The licensee's response dated April 22, 1980 proposed modified Technical Specifications designed to differentiate between barriers based on size of opening.

The staff has reviewed the licensee's proposal and found it to be unacceptable. The fire barrier penetration system consists of passive devices that must function in the event of a fire to mitigate the consequences. There is no room for compromise on this issue. The licensee has agreed to accept the Technical Specifications as modified to remove the dependence on barrier size.

UNITED STATES NUCLEAR REGULATORY COMMISSION

DOCKET NOS. 50-325 AND 50-324

CAROLINA POWER & LIGHT COMPANY

NOTICE OF ISSUANCE OF AMENDMENTS TO FACILITY OPERATING LICENSES

The U. S. Nuclear Regulatory Commission (the Commission) has issued Amendment Nos. 28 and 51 to Facility Operating License Nos. DPR-71 and DPR-62 issued to Carolina Power & Light Company (the licensee) which revised the Technical Specifications for operation of the Brunswick Steam Electric Plant, Unit Nos. 1 and 2 (BSEP Units 1 and 2, the facility), located in Brunswick County, North Carolina. The amendments are effective as of the date of issuance.

The amendment for BSEP Unit No. 2 changes the Technical Specifications to establish revised safety and operating limits for operation in fuel Cycle No. 4, and revises the table of safety related hydraulic snubbers.

The amendments for BSEP Unit Nos. 1 and 2 change the Technical Specifications to (1) conform to the installed Degraded Grid Voltage Protection system, (2) provide for the End-of-Cycle Recirculation Pump Trip feature, (3) allow lowering the reactor vessel water level for extended maintenance during refueling outages, (4) reflect revisions in the corporate organizational structure, (5) change operability test requirements for the RHR Service Water Pumps (6) clarify reporting requirements in the Appendix B Environmental Technical Specifications, and (7) upgrade fire protection provisions. In addition, the language of the Reactor Protection System Instrumentation Specification was revised, and other was revised, and other miscellaneous editorial changes were made to bring the BSEP Technical Specifications into conformance with the current General Electric Technical Specifications.

The applications for the amendments comply with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations. The Commission has made appropriate findings as required by the Act and the Commission's rules and regulations in 10 CFR Chapter I, which are set forth in the license amendments. Prior public notice of the amendments was not required since the amendments do not involve a significant hazards consideration.

The Commission has determined that the issuance of the amendments will not result in any significant environmental impact and that pursuant to 10 CFR Section 51.5(d)(4), an environmental impact statement or negative declaration and environmental impact appraisal need not be prepared in connection with issuance of the amendments.

For further details with respect to this action, see (1) the licensee's submittals dated October 25, December 27, 1976: July 28, 1977; January 18, February 2, March 6, March 21, April 13, April 27, May 1, May 29, October 8, November 7, December 31, 1979; February 5, February 20, April 1, April 11, April 22, May 21, and May 27, 1980, (2) Amendment Nos. 28 and 51 to License Nos. DPR-71 and DPR-62, and (3) the Commission's related Safety Evaluation. These items are available for public inspection at the Commission's Public Document Room, 1717 H Street, N.W., Washington, D. C. and at the Southport-Brunswick County Library, 109 West Moore Street, Southport, North Carolina, 28461. A copy of items (2) and (3) may be obtained upon request addressed to the U. S. Nuclear Regulatory Commission, Washington, D. C. 20555, Attention: Director, Division of Licensing.

Dated at Bethesda, Maryland this 11th day of June, 1980

FOR THE NUCLEAR REGULATORY COMMISSION

RBBevan

Roby B. Bevan, Acting Chief
Operating Reactors Branch #2
Division of Licensing