Docket File

DCS MS-016

JUL 28 1981

Docket Nos. 50-282
and 50-306

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U.S. NUCLEAR REGULATORY COMMISSION

Mr. L. O. Mayer, Manager
Nuclear Support Services
Northern States Power Company
414 Nicollet Mall - 8th Floor
Minneapolis, Minnesota 55401

Dear Mr. Mayer:

The Commission has issued the enclosed Amendments Nos. 49 and 43 to Facility Operating Licenses Nos. DPR-42 and DPR-60 for the Prairie Island Nuclear Generating Plant, Unit Nos. 1 and 2, respectively. The amendments are in response to the matters listed below:

- NSP application dated May 16, 1980 addressing degraded grid voltage, emergency charcoal filter system, containment fan coolers, residual heat removal system, diesel generator surveillance, shock suppressors, miscellaneous corrections, organizational changes, and a clarification of the term operability.

- Clarification and correction of typographical errors contained in license Paragraph 2.C.(3) on Physical Protection programs.

- Clarification and correction of typographical errors and ommissions resulting from the issuance of Amendment 46/40 and 47/41 concerning Technical Specification pages 3.1-2, 3.1-3, 3.1-3A and 4.1-2A.

- NSP application dated February 20, 1980 addressing the control rod position indication system.

- NSP application dated July 31, 1980 addressing the fire protection systems.

OFFICE ▶	8108170470 810728						
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DATE ▶	P PDR						

JUL 28 1981

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

Sincerely,

Original signed by
Robert A. Clark
Robert A. Clark, Chief
Operating Reactors Branch #3
Division of Licensing

Enclosures:
1. Amendment No. 49 to DPR-42
2. Amendment No. 43 to DPR-60
3. Safety Evaluation
4. Notice of Issuance

cc: w/enclosures
See next page

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cc w/enclosure(s) and incoming
dated: 2/20/80, 5/16/80, 7/31/80

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

NORTHERN STATES POWER COMPANY

DOCKET NO. 50-282

PRAIRIE ISLAND NUCLEAR GENERATING PLANT UNIT NO. 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 49
License No. DPR-42

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

   A. The applications for amendment by Northern States Power Company (the licensee) dated February 20, 1980, May 16, 1980, and July 31, 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 application, the provisions of the Act, and the rules and regulations of the Commission;

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

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

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

2. Accordingly, Facility Operating License No. DPR-42 is amended by revising paragraphs 2.C.(2) and 2.C.(3) to read as follows:

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 49 , are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

(3) Physical Protection

The licensee shall fully implement and maintain in effect all provisions of the following Commission approved documents, including amendments and changes made pursuant to the authority of 10 CFR 50.54(p). These approved documents consist of information withheld from public disclosure pursuant to 10 CFR 2.790(d):

a. "Prairie Island Nuclear Generating Plant Security Plan" -- Revision 4 filed on March 3, 1978 and Revision 5 filed September 25, 1978.

b. "Prairie Island Nuclear Generating Plant Safeguards Contingency Plan" dated March 23, 1979, as revised by submittal dated August 20, 1980 which contained revised pages dated July 1, 1980, submitted pursuant to 10 CFR 73.40. The Contingency Plan shall be fully implemented, in accordance with 10 CFR 73.40(b), within 30 days of approval by the Commission (February 25, 1981).

c. "Prairie Island Nuclear Generating Plant Security Guard Force Training and Qualification Plan", submitted by letter dated August 17, 1979 as amended by Revision 1 submitted May 16, 1980. This Plan shall be followed in accordance with 10 CFR 73.55(b)(4), 60 days after approval by the Commission (February 25, 1981). All security personnel, as required in the above plans, shall be qualified within two years of this approval (February 25, 1981). The licensee may make changes to this plan without prior Commission approval if the changes do not decrease the safeguards effectiveness of the plan. The licensee shall maintain records of and submit reports concerning such changes in the same manner as required for changes made to the Safeguards Contingency Plan pursuant to 10 CFR 50.54(p).

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

FOR THE NUCLEAR REGULATORY COMMISSION

R. A. Clark

R. A. Clark, Chief
Operating Reactors Branch #3
Division of Licensing

Attachment:
Changes to the Technical
' Specifications

Date of Issuance: July 28, 1981

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

NORTHERN STATES POWER COMPANY

DOCKET NO. 50-306

PRAIRIE ISLAND NUCLEAR GENERATING PLANT UNIT NO. 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 43
License No. DPR-60

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

   A. The applications for amendment by Northern States Power Company (the licensee) dated February 20, 1980, May 16, 1980, and July 31, 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 application, the provisions of the Act, and the rules and regulations of the Commission;

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

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

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

2. Accordingly, Facility Operating License No. DPR-42 is amended by revising paragraphs 2.C.(2) and 2.C.(3) to read as follows:

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 43 , are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

(3) Physical Protection

The licensee shall fully implement and maintain in effect all provisions of the following Commission approved documents, including amendments and changes made pursuant to the authority of 10 CFR 50.54(p). These approved documents consist of information withheld from public disclosure pursuant to 10 CFR 2.790(d):

a. "Prairie Island Nuclear Generating Plant Security Plan" -- Revision 4 filed on March 3, 1978 and Revision 5 filed September 25, 1978.

b. "Prairie Island Nuclear Generating Plant Safeguards Contingency Plan" dated March 23, 1979, as revised by submittal dated August 20, 1980 which contained revised pages dated July 1, 1980, submitted pursuant to 10 CFR 73.40. The Contingency Plan shall be fully implemented, in accordance with 10 CFR 73.40(b), within 30 days of approval by the Commission (February 25, 1981).

c. "Prairie Island Nuclear Generating Plant Security Guard Force Training and Qualification Plan", submitted by letter dated August 17, 1979 as amended by Revision 1 submitted May 16, 1980. This Plan shall be followed in accordance with 10 CFR 73.55(b)(4), 60 days after approval by the Commission (February 25, 1981). All security personnel, as required in the above plans, shall be qualified within two years of this approval (February 25, 1981). The licensee may make changes to this plan without prior Commission approval if the changes do not decrease the safeguards effectiveness of the plan. The licensee shall maintain records of and submit reports concerning such changes in the same manner as required for changes made to the Safeguards Contingency Plan pursuant to 10 CFR 50.54(p).

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

FOR THE NUCLEAR REGULATORY COMMISSION

R. A. Clark, Chief
Operating Reactors Branch #3
Division of Licensing

Attachment:
Changes to the Technical
Specifications

Date of Issuance: July 28, 1981

ATTACHMENT TO LICENSE AMENDMENTS

AMENDMENT NO. 49 TO FACILITY OPERATING LICENSE NO. DPR-42

AMENDMENT NO. 43 TO FACILITY OPERATING LICENSE NO. DPR-60

DOCKET NOS. 50-282 AND 50-306

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

TS-iii
TS.1-4
TS.1-5
TS.3.1-2
TS.3.1-3
TS.3.1-3A
TS.3.3-4
TS.3.5-1
TS.3.5-3
Table TS.3.5-1 (Page 2 of 2) (New Page)
Table TS.3.5-6 (New Page)
TS.3.10-6
Table TS.3.12-1 (Page 1 of 8) (4 New Pages)
Through (Page 8 of 8)
TS.3.14-1
TS.3.14-2
TS.3.14-3
TS.3.14-4
TS.3.14-5
TS.3.14.6
Table TS.3.14-1 (pg 1 of 3)
Table TS.3.14-1 (pg 2 of 3)
Table TS.3.14-1 (pg 3 of 3)
Table TS.4.1-1 (Page 1 of 5)
Table TS.4.1-1 (Page 5 of 5)
Table TS.4.1-2A
TS.4.4-4
TS.4.5-2
TS.4.5-3A
TS.4.6-1
TS.4.16-2
TS.4.16-3
TS.4.16-4
TS.4.16-5
TS.4.16-6 (New Page)
TS.6.1-1
Figure TS.6.1-1
Figure TS.6.1-2
TS.6.2-1
TS.6.2-3
TS.6.2-5
TS.6.2-6
TS.6.4-1
TS.6.5-2

APPENDIX A TECHNICAL SPECIFICATIONS

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3.1-1	Unit 1 Reactor Vessel Toughness Data
3.1-2	Unit 2 Reactor Vessel Toughness Data
3.5-1	Engineered Safety Features Initiation Instrument Limiting Set Points
3.5-2	Instrument Operating Conditions for Reactor Trip
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3.5-4	Instrument Operating Conditions for Isolation Functions
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3.9-1	Radioactive Liquid Waste Sampling and Analysis
3.9-2	Radioactive Gaseous Waste Sampling and Analysis
3.12-1	Safety Related Shock Suppressors (Snubbers)
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4.1-1	Minimum Frequencies for Checks, Calibrations and Test of Instrument Channels
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4.4-1	Unit 1 and Unit 2 Penetration Designation for Leakage Tests
4.10-1	Prairie Island Nuclear Generating Plant-Radiation Environmental Monitoring Program Sample Collection and Analysis Environmental Monitoring Program
4.12-1	Steam Generator Tube Inspection
5.5-1	Anticipated Annual Release of Radioactive Material in Liquid Effluents From Prairie Island Nuclear Generating Plant (Per Unit)
5.5-2	Anticipated Annual Release of Radioactive Nuclides in Gaseous Effluent From Prairie Island Nuclear Generating Plant (Per Unit)
6.1-1	Minimum Shift Crew Composition
6.7-1	Special Reports

G. Limiting Safety System Settings

Limiting safety system settings are settings on protective instrumentation that initiate automatic protective action at a level such that safety limits will not be exceeded.

H. Limiting Conditions for Operation

Limiting conditions for operation are those restrictions on unit operation resulting from equipment performance capability that must be met in order to assure safe operation of the unit.

I. Operable

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 electrical 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).

When a system, subsystem, train, component or device is determined to be inoperable solely because its emergency power source is inoperable, or solely because its normal power source is inoperable, it may be considered operable for the purpose of satisfying the requirements of its applicable Limiting Condition for Operation, provided: (1) its corresponding normal or emergency power source is operable; and (2) all of its redundant system(s), subsystem(s), train(s), component(s) and device(s) are OPERABLE, or likewise satisfy the requirements of this paragraph.

The operability of a system or component shall be considered to be established when: (1) it satisfies the Limiting Conditions for Operation in Specification 3.0, (2) it has been tested periodically in accordance with Specification 4.0 and has met its performance requirements, and (3) its condition is consistent with the two paragraphs above in this TS section 1.1.

J. Power Operation

Power operation of a unit is any operating condition that results when the reactor of that unit is critical, and the neutron flux power range instrumentation indicates greater than 2% of rated power.

K. Protection Instrumentation and Logic

1. Protection System

The protection system consists of both the reactor trip system and the engineered safety feature system. The protection system encompasses all electrical and mechanical devices and circuitry (from sensors through the actuating devices) which are required to operate in order to produce the required protective function. Tests of protection systems will be considered acceptable when overlapped if run in parts.

2. Protection System Channel

A protection system channel is an arrangement of components and modules as required to generate a single protective action signal when required by a unit condition. The channel loses its identity where single action signals are combined.

3. Logic Channel

A logic channel is a group of relay contact matrices which operate in response to analog channel signals to generate a protective action signal.

L. <u>Quadrant Power Tilt</u>

Quadrant power tilt is the ratio of the maximum quadrant power indicated by an upper excore detector to the average reactor power indicated by the upper excore detectors or the ratio of the maximum quadrant power indicated by a lower excore detector to the average reactor power indicated by the lower excore detectors, whichever is greater. Power is proportional to excore detector current times its calibration factor. Percentage quadrant power tilt is 100 times the amount the quadrant power tilt ratio exceeds one.

M. <u>Rated Power</u>

Rated power of a unit is the steady state heat output of 1650 megawatts thermal (MWt) from the reactor core of that unit.

N. <u>Reactor Critical</u>

A reactor is critical when the neutron chain reaction is self-sustaining and $k_{eff} = 1.0$.

O. <u>Refueling Operation</u>

Refueling operation of a unit is any operation involving movement of those core components that could affect the reactivity of the core when the reactor vessel head is unbolted or removed.

P. <u>Shutdown</u>

1. Hot Shutdown

A reactor is in the hot shutdown condition when the reactor is subcritical by an amount greater than or equal to the margin as specified in Figure TS.3.10-1 and the reactor coolant average temperature is 547°F or greater.

2. Cold Shutdown

A reactor is in the cold shutdown condition when the reactor is subcritical by at least 1% $\Delta k/k$ and the reactor coolant average temperature is less than 200°F.

4. Pressurizer

   a. Whenever average reactor coolant system temperature is above 350°F or the reactor is critical, the pressurizer shall be operable with:

      1. Steam bubble

      2. Pressurizer heater groups "A" and "B" and their associated safeguards power supplies operable

      3. At least one operable spray

   b. With the pressurizer inoperable due to an inoperable heater group restore the equipment to operable status within 72 hours or place the reactor in at least Hot Shutdown within the following 18 hours.

   c. With the pressurizer inoperable for any other reason than (b) above, the reactor shall be placed in at least Hot Shutdown within the following 12 hours.

   d. At least one pressurizer safety valve shall be operable whenever the head is on the reactor vessel, except during hydrostatic tests. Both pressurizer safety valves shall be operable whenever average reactor coolant system temperature is above 350°F or the reactor is critical. Pressurizer safety valve lift setting shall be 2485 psig ± 1%.

   e. Except as specified in (f) and (g) below, two power operated relief valves (PORV's) and their associated block valves shall be operable whenever average reactor coolant system temperature is above 350°F or the reactor is critical.

   f. With one or more PORV's inoperable, within one hour either restore the PORV(s) to operable status or close the associated block valve(s). If this cannot be done, place the reactor in the Cold Shutdown condition within the following 36 hours.

   g. With one or more block valves inoperable, within one hour either restore the block valve(s) to operable status or close the valve. If this cannot be done, place the reactor in the Cold Shutdown condition within the following 36 hours.

Basis

When the boron concentration of the reactor coolant system is to be reduced, the process must be uniform to prevent sudden reactivity changes in the reactor. Mixing of the reactor coolant will be sufficient to maintain a uniform boron concentration if at least one reactor coolant pump or one residual heat removal pump is running while the change is taking place. The residual heat removal pump will circulate the equivalent of the primary system volume in approximately one-half hour.

"Steam Generator Tube Surveillance", Technical Specification 4.12, identifies steam generator tube imperfections having a depth $\geq$50% of the 0.050-inch tube wall thickness as being unacceptable for power operation. The results of steam generator burst and tube collapse tests submitted to the staff have demonstrated that tubes having a wall thickness greater than 0.025-inch have adequate margins of safety against failure due to loads imposed by normal plant operation and design basis accidents.[2]

Part A of the specification requires that both reactor coolant pumps be operating when the reactor is critical to provide core cooling in the event that a loss of flow occurs. In the event of the worst credible coolant flow loss (loss of both pumps from 100% power) the minimum calculated DNBR remains well above 1.30. Therefore, cladding damage and release of fission products to the reactor coolant will not occur. Critical operation, except for low power physics tests, with less than two pumps is not planned. Above 10% power, an automatic reactor trip will occur if flow from either pump is lost. Below 10% power, a shutdown under administrative control will be made if flow from either pump is lost.

The pressurizer is needed to maintain acceptable system pressure during normal plant operation, including surges that may result following anticipated transients. Each of the pressurizer safety valves is designed to relieve 325,000 lbs per hour of saturated steam at the valve set point. Below 350°F and 450 psig in the reactor coolant system, the residual heat removal system can remove decay heat and thereby control system temperature and pressure. If no residual heat were removed by any of the means available, the amount of steam which could be generated at safety valve relief pressure would be less than half the valves' capacity. One valve therefore provides adequate defense against over-pressurization of the reactor coolant system for reactor coolant temperatures less than 350°F. The combined capacity of both safety valves is greater than the maximum surge rate resulting from complete loss of load.[1]

References

[1]FSAR, Section 14.1.9.

[2]Testimony by J. Knight in the Prairie Island Public Hearing on January 28, 1975.

Basis (continued)

The requirement that two groups of pressurizer heaters be operable provides assurance that at least one group will be available during a loss of offsite power to maintain natural circulation. Backup heater group "A" is normally supplied by one safeguards bus. Backup heater group "B" can be manually transferred within minutes to the redundant safeguards bus. Tests have confirmed the ability of either group to maintain natural circulation conditions.

The pressurizer power operated relief valves (PORV's) operate to relieve reactor coolant system pressure below the setting of the pressurizer Code safety valves. These relief valves have remotely operated block valves to provide a positive shutoff capability should a relief valve become inoperable. The PORV's are pneumatic valves operated by instrument air. They fail closed on loss of air or loss of power to their DC solenoid valves. The PORV block valves are motor operated valves supplied by the 480 volt safeguards buses.

The Specifications require that at least two methods of removing decay heat are available for each reactor. Above 350°F, both steam generators must be operable to serve this function. Below 350°F, either a steam generator or a residual heat removal loop are capable of removing decay heat and any combination of two loops is specified. If redundant means are not available, the reactor is placed in the cold shutdown condition.

References

[1] FSAR, Section 14.1.9

[2] Testimony by J Knight in the Prairie Island Public Hearing on January 28, 1975.

c. Any redundant valve or damper required for functioning of the containment air cooling system and the containment spray system during and following accident conditions may be inoperable provided it is restored to operable status within 24 hours. Prior to initiating repairs, all valves in the system that provide redundancy shall be demonstrated to be operable.

C. Component Cooling Water System

1. Single Unit Operation

a. A reactor shall not be made or maintained critical nor shall it be heated or maintained above 200°F, unless the following conditions are satisfied, except as permitted in Specification 3.3 C.1.b. below.

(1) The two component cooling pumps assigned to that unit are operable.

(2) The two component cooling heat exchangers assigned to that unit are operable.

(3) All valves, interlocks, instrumentation and piping associated with the above components, and required for the functioning of the system during accident conditions, are operable.

b. During startup operation or power operation, any one of the following conditions of inoperability may exist provided startup operation is discontinued until operability is restored. The reactor shall be placed in the hot shutdown condition if during power operation operability is not restored within the time specified, and it shall be placed in the cold shutdown condition if operability is not restored within an additional 48 hours.

(1) One of the assigned component cooling pumps may be out of service for a period not to exceed 24 hours.

(2) One of the assigned component cooling heat exchangers may be out of service for a period not to exceed 48 hours.

2. Two-Unit Operation

a. A second reactor shall not be made or maintained critical nor shall it be heated or maintained above 200°F, unless the following conditions are satisfied, except as provided by Specification 3.3 C.2.b. below.

3.5 INSTRUMENTATION SYSTEM

Applicability

Applies to protection system instrumentation.

Objectives

To provide for automatic initiation of the engineered safety features in the event that principal process variable limits are exceeded, and to delineate the conditions of the reactor trip and engineered safety feature instrumentation necessary to ensure reactor safety.

Specification

A. Limiting set points for instrumentation which initiates operation of the engineered safety features shall be as stated in Table TS.3.5-1.

B. For on-line testing or in the event of failure of a sub-system instrumentation channel, plant operation shall be permitted to continue at rated power in accordance with Tables TS.3.5-2 through TS.3.5-6.

C. If the number of channels of a particular sub-system in service falls below the limits given in the column entitled Minimum Operable Channels, or if the specified Minimum Degree of Redundancy cannot be achieved, operation shall be limited according to the requirement shown in the column titled Operator Action of Tables TS.3.5-2 through TS.3.5-6.

D. In the event of sub-system instrumentation channel failure permitted by Specification 3.5.B, the requirements of Tables TS.3.5-2 through TS.3.5-6 need not be observed during the short period of time the operable sub-system channels are tested where the failed channel must be blocked to prevent unnecessary reactor trip. If the test time exceeds four hours, operation shall be limited according to the requirement shown in the column titled Operator Action of Tables TS.3.5-2 through TS.3.5-6.

Basis

Instrumentation has been provided to sense accident conditions and to initiate reactor trip and operation of the Engineered Safety Features (1).

Steam Line Isolation

In the event of a steam line break, the steam line stop valve of the affected line is automatically isolated to prevent continuous, uncontrolled steam release from more than one steam generator. The steam lines are isolated on high containment pressure (Hi-Hi) or high steam line flow in coincidence with low T_{avg} and safety injection or high steam flow (Hi-Hi) in coincidence with safety injection. Adequate protection is afforded for breaks inside or outside the containment even when it is assumed that the steam line check valves do not function properly.

Containment Ventilation Isolation

Valves in the containment purge and inservice purge systems automatically close on receipt of a Safety Injection signal or a high radiation signal. Gaseous and particulate monitors in the exhaust stream or a gaseous monitor in the exhaust stack provide the high radiation signal.

Ventilation System Isolation

In the event of a high energy line rupture outside of containment, redundant isolation dampers in certain ventilation ducts are closed.[4]

Safeguards Bus Voltage

Relays are provided on buses 15, 16, 25, and 26 to detect loss of voltage and degraded voltage (the voltage level at which safety related equipment may not operate properly). On loss of voltage, the automatic voltage restoring scheme is initiated immediately. When degraded voltage is sensed, the voltage restoring scheme is initiated if acceptable voltage is not restored within a short time period. This time delay prevents initiation of the voltage restoring scheme when large loads are started and bus voltage momentarily dips below the degraded voltage setpoint.

Auxiliary Feedwater System Actuation

The following signals automatically start the pumps and open the steam admission control valve to the turbine driven pump of the affected unit:

1. Low-low water level in either steam generator
2. Trip of both main feedwater pumps
3. Safety Injection signal
4. Undervoltage on both 4.16 KV normal buses (turbine driven pump only)

Manual control from both the control room and the Hot Shutdown Panel are also available. The design provides assurance that water can be supplied to the steam generators for decay heat removal when the normal feedwater system is not available.

Limiting Instrument Setpoints

1. The high containment pressure limit is set at about 10% of the maximum internal pressure. Initiation of Safety Injection protects against loss of coolant[(2)] or steam line break accidents as discussed in the safety analysis.

2. The Hi-Hi containment pressure limit is set at about 50% of the maximum internal pressure for initiation of containment spray and at about 30% for initiation of steam line isolation. Initiation of Containment Spray and Steam Line Isolation protects against large loss of coolant[(2)] or steam line break accidents[(3)] as discussed in the safety analysis.

3. The pressurizer low pressure limit is set substantially below system operating pressure limits. However, it is sufficiently high to protect against a loss of coolant accident as shown in the safety analysis.[(2)]

4. The steam line low pressure signal is lead/lag compensated and its set-point is set well above the pressure expected in the event of a large steam line break accident as shown in the safety analysis.[(3)]

5. The high steam line flow limit is set at approximately 20% of nominal full-load flow at the no-load pressure and the high-high steam line flow limit is set at approximately 120% of nominal full-load flow at the full load pressure in order to protect against large steam break accidents. The coincident low T_{avg} setting limit for steam line isolation initiation is set below its hot shutdown value. The safety analysis shows that these settings provide protection in the event of a large steam break.[(3)]

6. Steam generator low-low water level and 4.16 KV Bus 11 and 12 (21 and 22 in Unit 2) low bus voltage provide initiation signals for the Auxiliary Feedwater System. Selection of these setpoints is discussed in Section 2.3 of the Technical Specifications.

7. High radiation signals providing input to the Containment Ventilation Isolation circuitry are set in accordance with the Radioactive Effluent Technical Specifications. The setpoints are established to prevent exceeding the limits of 10 CFR Part 20 at the site boundary.

8. The degraded voltage protection setpoint is 90$\pm$ 2% of nominal 4160 V bus voltage. Testing and analysis have shown that all safeguards loads will operate properly at or above the degraded voltage setpoint. The degraded voltage protection time delay of 6$\pm$2 seconds has been shown by testing and analysis to be long enough to allow for voltage dips resulting from the starting of large loads. This time delay is also consistent with the maximum time delay assumed in the ECCS analysis for starting of a safety injection pump. A maximum limit on the degraded voltage setpoint has been established to prevent unnecessary actuation of the voltage restoring scheme.

   The loss of voltage protection setpoint is approximately 55% of nominal 4160 V bus voltage. Relays initiate a rapid (less than two seconds) transfer to an alternate source on loss of voltage.

TABLE TS.3.5-1 (continued)

ENGINEERED SAFETY INITIATION INSTRUMENTATION LIMITING SET POINTS

FUNCTIONAL UNIT	CHANNEL	LIMITING SET POINTS
10. 4KV Safeguards Busses Voltage Restoration	a. Degraded Voltage	
	Voltage (% nominal)	90 ± 2%
	Time Delay	6 ± 2 sec
	b. Loss of Voltage	
	1. Voltage (% nominal)	55% ± 10%
	Time Delay	2 ± 2 sec
	2. Voltage (% nominal)	90 ± 2%
	Time Delay	2 ± 2 sec

TABLE TS.3.5-6

INSTRUMENT OPERATING CONDITIONS FOR AUXILIARY ELECTRICAL SYSTEM

FUNCTIONAL UNIT	1 MINIMUM OPERABLE CHANNELS	2 MINIMUM DEGREE OF REDUNDANCY	3 PERMISSIBLE BYPASS CONDITIONS	4 OPERATOR ACTION IF CONDITIONS OF COLUMN 1 OR 2 CANNOT BE MET
1. Degraded Voltage 4KV Safeguards Busses	1/Bus	1/Bus	---	Place inoperable channel in the tripped condition within one hour of hot shutdown.***
2. a. Loss of voltage 4KV Safeguard Bus (90%)	1/Bus	1/Bus	---	Place inoperable channel in the tripped condition within one hour of hot shutdown.***
b. Loss of voltage 4KV Safeguard Bus (55%)	1/Bus	1/Bus	---	Place inoperable channel in the tripped condition within one hour of hot shutdown.***

***If minimum conditions are not met within 24 hours, steps shall be taken to place the unit in cold shutdown conditions.

E. Rod Misalignment Limitations

1. If a full-length rod cluster control assembly (RCCA) is misaligned from its bank by more than 15 inches, the rod will be realigned or the core power peaking factors shall be determined within 2 hours, and Specification 3.10.B applied. If peaking factors are not determined within 2 hours, the high neutron flux trip setpoint shall be reduced to 85 percent of rating.

2. a. If the bank demand position is greater than or equal to 215 steps, or less than or equal to 30 steps and the rod position indicator channel differs by more than 24 steps, that rod control cluster assembly (RCCA) shall be considered misaligned.

   b. If the bank demand position is between 30 and 215 steps and the rod position indicator channel differs by more than 12 steps, that RCCA shall be considered misaligned.

3. If the misaligned RCCA is not realigned within a total of 8 hours, the RCCA shall be declared inoperable.

F. Inoperable Rod Position Indicator Channels

1. If a rod position indicator (RPI) channel is out of service then

   a. For operation between 50% and 100% of rating, the position of the RCCA shall be checked directly by core instrumentation (excore detector and/or thermocouples and/or movable incore detectors) every shift or subsequent to rod motion exceeding a total of 24 steps, whichever occurs first.

   b. During operation below 50% of rating, no special monitoring is required.

2. The plant shall be brought to the hot shutdown condition should more than one RPI channel per group or more than two RPI channels per bank be found to be inoperable during power operation.

3. If a full length rod having a rod position indicator channel out of service is found to be misaligned from 1.a. above, then apply Specification 3.10.E.

G. Inoperable Rod Limitations

1. An inoperable rod is a rod which (a) does not trip, (b) is declared inoperable under Specification 3.10.E or 3.10.H or (c) cannot be moved by its drive mechanism and cannot be corrected within 8 hours.

SAFETY RELATED SHOCK SUPPRESSORS (SNUBBERS)

Snubber No.	Location	Elevation	Accessible or Inaccessible (A or I)	Snubbers Especially Difficult to Remove	In High Radiation Area During Shutdown
	UNIT I				
AFSH-22 A&B	Main and Auxiliary Steam	773'-4-1/4"	A		
AFSH-36		745'-7-1/4"	A		
AFSH-39		699'-10-1/4"	A		
AFSH-48		699'-6-1/4""	A		
MSDH-25		736'-6-7/16"	A	X	
MSDH-26		756'-7-1/4"	A	X	
MSDH-29		756'-7-1/4"	A		
MSDH-30		736-6-7/16"	A		
MSH-48		739'-1-11/16"	A	X	
MSH-62 A&B		735'-6"	A		
MSH-68 A&B		755'-8"	A		
	UNIT II				
AFSH-2	Main and Auxiliary Steam	749'-4"	A		
AFSH-19		745'-7-1/4"	A		
AFSH-20		745'-7-1/4"	A		
AFSH-24		745'-6"	A		
AFSH-29 A&B		721'-1-9/16"	A		
AFSH-33		707'-5"	A		
AFSH-39		696'-6-1/4"	A		
AFSH-40		696'-6-1/4"	A		
AFSH-44		750'-7-1/2"	A		
AFSH-46		750'-7"	A		
MSDH-17		739'-0"	A	X	
MSDH-18		759'-0"	A	X	
MSDH-19		739'-0"	A		
MSDH-20		759'-0"	A		

Snubber No	Location	Elevation	Accessible or Inaccessible (A or I)	Snubbers Especially Difficult to Remove	In High Radiation Areas During Shutdown
	UNIT II				
MSH-23	Main and Auxiliary	739'-1-3/16"	A	X	
MSH-54 A&B	Steam	756'-0-1/16"	I		
MSH-81 A&B		735'-9"	A		
MSH-82 A&B		755'-8"	A		
MSH-83		761'-13/16""	I		
	UNIT I				
RHRRH-5	Safety Injection	723'-4-1/4"	I		
RHRRH-41		698'-11"	I		
RHRRH-58		670'-0"	A		
RHRRH-60		670'-0"	A		
RPCH-160		718'-1/2"	I		
RSIH-92		714'-11"	I		
RSIH-93		714'-11"	I		
RSIH-95		711'-2"	I		
RSIH-96		711'-2"	I		
RSIH-98		701'-2"	I		
RSIH-163		717'-9"	I		
RSIH-167		717'-9"	I		
RSIH-413 A&B		722'-8"	A		
RSIH-414		716'-10"	I		
RSIH-442		717'-9-1/2"	I		
RSIH-469		707'-6-1/2"	I		
RSIH-476		707'-1-3/4"	I		
SIRH-9		737'-0"	I		
SIRH-11		718'-6""	I		
SIRH-17		730'-0"	I		
SIRH-18		730'-0"	I		
SIRH-22		711'-4"	I		
SIRH-23 A&B		711'-4"	I		

SAFETY RELATED SHOCK SUPPRESSORS (SNUBBERS)

Snubber No.	Location	Elevation	Accessible or Inaccessible (A or I)	Snubbers Especially Difficult to Remove	In High Radiation Areas During Shutdown
	UNIT II				
RHRH-13	Safety Injection	673'-9"	A		
RHRH-14		674'-0"	A		
RHRH-52		670'-6"	A		
RHRH-54		670'-6"	A		
RHRRH-19		700'-11"	I		
RHRRH-23		711'-2"	I		
RHRRH-28		707'-4"	I		
RSIH-265		699'-9"	I		
RSIH-268		713'-9-3/16"	I		
RSIH-343		719'-8-11/16"	I		
RSIH-349		703'-11"	I		
RSIH-350		703'-11"	I		
RSIH-353 A&B		701'-9"	I		
SIH-43		720'-0"	A		
SIH-49 A&B		737'-3"	A		
SIH-53		710'-3"	A		
SIRH-4A		711'-6-1/8"	I		
SIRH-4B		711'-3"	I		
SIRH-7		716'-3-1/16"	I		
SIRH-18		722'-6"	I		

SAFETY RELATED SHOCK SUPPRESSORS (SNUBBERS)

Snubber No.	Location	Elevation	Accessible or Inaccessible (A or I)	Snubbers Especially Difficult to Remove	In High Radiation Areas During Shutdown
	UNIT I				
RCRH-5 A&B	Reactor Coolant	732'-6"	I		
RCRH-12 A&B		720'-7"	I		
RCRH-26		762'-8"	I		
RCRH-27 A&B		761'-7"	I		
RCRH-34		764'-7"	I		
RCRH-45		765'-1"	I		
RERH-46		765'-1"	I		
RCRH-47		745'-10"	I		
RHRRH-15		705'-6"	I		
RHRRH-27		705'-6"	I		
RHRRH-29 A&B		705'-6"	I		
	UNIT II				
RCRH-5	Reactor Coolant	731'-6"	I		
RCRH-8		717'-6"	I		
RCRH-9		712'-0"	I		
RCRH-14		705'-9"	I		
RCRH-20		715'-7"	I		
RCRH-25		732'-2"	I		
RCRH-26		757'-7"	I		
RCRH-31		764'-1"	I		
RCRH-45		724'-6"	I		
RCRH-46		758'-3"	I		
RCRH-47		760'-3"	I		
RCRH-48		765'-1"	I		
RCRH-49		765'-1"	I		
RRCH-279 A&B		724'-9"	I		
RRCH-282		723'-2"	I		
RRCH-284 A&B		725'-8"	I		
RHRRH-2		699'-0"	I		
RHRRH-4		705'-11"	I		
RHRRH-9		705'-11"	I		
RHRRH-15		699'-0"	I		

SAFETY RELATED SHOCK SUPPRESSORS (SNUBBERS)

Snubber No.	Location	Elevation	Accessible or Inaccessible (A or I)	Snubbers Especially Difficult to Remove	In High Radiation Areas During Shutdown
	UNIT I				
CWH-359	Cooling Water	705'-8"	A		
CWH-380		706'-11"	A		
CWH-385		709'-0"	A		
CWH-394		731'-0"	A		
CWH-395		746'-6"	A		
CWH-405		707'-10"	A		
CWH-429		722'-11"	A		
CWH-432		722'-11"	A		
CWH-433		735'-11"	A		
CWH-434		735'-11"	A		
CWH-436		737'-11"	A		
	UNIT II				
CWH-34	Cooling Water	709'-3"	A		
CWH-35		746'-8"	A		
CWH-39		710'-6"	A		
CWH-40		710'-6"	A		
CWH-44		730'-11"	A		
CWH-45		709'-0"	A		
CWH-49		723'-0"	A		
CWH-50		723'-10"	A		
CWH-52		736'-0"	A		
CWH-54		738'-0"	A		

SAFETY RELATED SHOCK SUPPRESSORS (SNUBBERS)

Snubber No.	Location	Elevation	Accessible or Inaccessible (A or I)	Snubbers Especially Difficult to Remove	In High Radiation Areas During Shutdown
	UNIT I				
AFWH-72	Feedwater	752'-0"	I		
AFWH-82		728'-11"	A		
AFWH-84		728'-11"	A		
	UNIT II				
AFWH-72 A&B	Feedwater	706'-3/4"	A		
FWH-72 A&B		751'-0"	I		
	UNIT I				
25.12620.003 3	Steam Generator	760'-9-1/2"	I	X	
25.12620.003 - 4		760'-9-1/2"	I	X	
25.12620.003 - 5		760'-9-1/2"	I	X	
25.12620.003 - 6		760'-9-1/2"	I	X	
25.12620.003 - 7		760'-9-1/2"	I	X	
25.12620.003 - 8		760'-9-1/2"	I	X	
25.12620-003 - 10		760'-9-1/2"	I	X	
25.12620.003 - 15		760'-9-1/2"	I	X	
	UNIT II				
25.12620.003 - 1		760'-9-1/2"	I	X	
25.12620.003 - 2		760'-9-1/2"	I	X	
25.12620.003 - 9		760'-9-1/2"	I	X	
25.12620.003 - 11		760'-9-1/2"	I	X	
25.12620.003 - 12		760'-9-1/2"	I	X	
25.12620.003 - 13		760'-9-1/2"	I	X	
25.12620.003 - 14		760'-9-1/2"	I	X	
25.12620.003 - 16		760'-9-1/2"	I	X	
	UNIT I				
CVCH-182	Chemical & Vol	707'-6"	A		
RCRH-16 A&B	Control	705'-2"	I		
RCRH-19		705'-2"	I		
RCRH-21		705'-7"	I		
RCRH-23 A&B		715'-11"	I		
RCVCH-907 A&B		717'-11"	I		
RCVCH-1293		712'-0"	I		
RPCH-22		703'-1"	I		
RPCH-23		703'-1"	I		
RPCH-121		707'-9"	I		
RPCH-139		704'-4"	I		
RPCH-140		707'-7"	I		
PRCH-146		714'-7"	I		
RPCH-147		714'-10"	I		
WDRH-24		707'-9"	I		

SAFETY RELATED SHOCK SUPPRESSORS (SNUBBERS)

Snubber No.	Location	Elevation	Accessible or Inaccessible (A or I)	Snubbers Especially Difficult to Remove	In High Radiation Areas During Shutdown
	UNIT II				
RCVCH-1396	Chemical & Vol	702'-10"	I		
RCVCH-1505	Control	708'-6"	I		
RCVCH-1513		710'-1"	I		
RCVCH-1524		719'-1"	I		
RCVCH-1574		721'-0"	I		
RCVCH-1668		705'-5"	I		
RCVCH-1373		722'-11"	I		
RCVCH-1389		706'-1"	I		
RRCH-253		704'-4"	I		
RRCH-255		704'-8"	I		
RRCH-261		707'-2"	I		
RRCH-288		707'-2"	I		
RRCH-291		704'-6"	I		
RRCH-292		704'-7"	I		
	UNIT I				
CCH-304	Comp Cooling	717'-7"	A		
CCH-373		712'-4"	A		
CCH-376 A&B		700'-5"	A		
CCH-377		703'-0"	A		
CCH-378		708'-4"	A		
CCH-380		670'-8"	A		
CCH-381 A&B		671'-4"	A		
CCH-397		699'-3"	A		
CCH-398 A&B		671'-4"	A		
	UNIT II				
CCH-161	Comp Cooling	717'-7"	A		
CCH-166		719'-11"	A		
CCH-167		720'-0"	A		
CCH-172		720'-0"	A		
CCH-173		708'-5"	A		
CCH-176		705'-3"	A		
CCH-179 A&B		671'-4"	A		
CCH-180		670'-8"	A		
CCH-181		708'-4"	A		
CCH-182		704'-2"	A		
CCH-185 A&B		671'-4"	A		
CCH-186		670'-10"	A		
	UNIT I				
RCSH-81	Containment Spray	76"'-9"	I		
RCSH-82		760'-8"	I		
RSCH-83 A&B		732'-1"	I		
	UNIT II				
CSH-75 A&B	Containment Spray	731'-10"	I		
CSH-76		752'-7"	I		
CSH-79		751'-9"	I		
CSH-82 A&B		731'-11"	I		
CSH-83		767'-2"	I		
CSH-84		767'-2"	I		
CSH-210		698'-0"	I		
CSH-215		698'-0"	A		
CSH-224		710'-6"	A		

SAFETY RELATED SHOCK SUPPRESSORS (SNUBBERS)

Snubber No.	Location	Elevation	Accessible or Inaccessible (A or I)	Snubbers Especially Difficult to Remove	In High Radiation Areas During Shutdown
	UNIT I				
RRHH-20	RHR	704'-3"	A		
RRHH-62		705'-10"	A		
	UNIT II				
CVCRH-6	RHR	711'-0"	I		
RRHH-21		704'-6"	A		

3.14 FIRE DETECTION AND PROTECTION SYSTEMS

Applicability

Applies to instrumentation and plant systems used for fire detection and protection of the nuclear safety-related structures, systems, and components of the plant.

Objective

To insure that the structures, systems, and components of the plant important to nuclear safety are protected from fire damage.

Specification

A. Fire Detection Instrumentation

1. Except as specified below, the minimum fire detection instrumentation for each fire detection zone shown in Table 3.14-1 shall be operable whenever equipment in that fire detection zone is required to be operable. Fire detection instruments located within containment are not required to be operable during the performance of Type A containment leakage rate tests.

2. If Specification 3.14.A.1 cannot be met:

   a. Within one hour, establish a fire watch patrol to inspect the zone with the inoperable instruments at least once per hour. Fire zones located inside primary containment are exempt from this requirement when containment integrity is required.

   b. Restore the inoperable instruments to operable status within 14 days or submit a 30-day written report outlining the cause of the malfunction and the plans for restoring the instruments to operable status.

B. Fire Suppression Water System

1. Except as specified in 3.14.B.2 or 3.14.B.3 below, the system shall be operable at all times with:

   a. The following pumps, including automatic initiation logic, operable and capable of delivering at least 2000 gpm at a discharge pressure of 108 psig.

      1. Diesel-driven fire pump
      2. Motor-driven fire pump
      3. Screen wash pump

b. An operable flow path capable of taking suction from the river and transferring the water through distribution piping with operable sectionalizing control or isolation valves to the yard hydrant valves and the first valve ahead of each deluge valve, hose station, or sprinkler system required to be operable.

2. With one or two of the pumps required by Specification 3.14.B.1.a inoperable, restore the inoperable equipment to operable status within seven days or provide a 30-day written report outlining the plans and procedures to be used to provide for the loss of redundancy in the Fire Suppression Water system. With an inoperable pump, perform the surveillance required by Specification 4.16.B.2.

3. With the fire suppression water system otherwise inoperable:

a. Establish a backup Fire Suppression Water System within 24 hours.

b. Provide prompt notification with a written followup report outlining the actions taken and the plans and schedule for restoring the system to operable status.

c. If Specification 3.14.B.3.a cannot be met, the reactors shall be placed in hot standby within 6 hours and in cold shutdown within 30 hours.

C. Spray and Sprinkler Systems

1. Whenever equipment protected by the following spray and sprinkler systems is required to be operable, the spray and sprinkler system shall be operable:

a. Auxiliary Feed Pump Room WP-10

b. Diesel Generator Areas PA-1

c. Unit No. 1 Electrical Penetration Area PA-3

d. Unit No. 1 Electrical Penetration Area PA-4

e. Unit No. 2 Electrical Penetration Area PA-6

f. Unit No. 2 Electrical Penetration Area PA-7

g. Screenhouse PA-9

2. If Specification 3.14.C.1 cannot be met, a continuous fire watch with backup fire suppression equipment shall be established within one hour. Restore inoperable spray and sprinkler systems to operable status within 14 days or submit a 30-day written report outlining the cause of inoperability and the plans for restoring the system to operable status.

D. Carbon Dioxide System

1. Except as specified in 3.14.D.3 below, the CO_2 system protecting the relay and cable spreading room area shall be operable with a minimum level of 60% in the CO_2 storage tank.

2. During those periods when the relay and cable spreading room area is normally occupied, automatic initiation of the CO_2 system may be bypassed. During those periods when the area is normally unoccupied, the CO_2 system shall be capable of automatic initiation unless there are personnel actually in the area.

3. If specification 3.14.D.1 cannot be met, a continuous fire watch with backup fire suppression equipment shall be stationed in the relay and cable spreading room within one hour. Restore the system to operable status within 14 days or submit a 30-day written report outlining the cause of inoperability and the plans for restoring the system to operable status.

E. Fire Hose Stations

1. Whenever equipment protected by hose stations in the following areas is required to be operable, the hose station(s) protecting that area shall be operable:

   a. Diesel Generator Rooms

   b. Safety Related Switchgear Rooms

   c. Safety Related Areas of Screenhouse

   d. Auxiliary Building

   e. Control Room

   f. Relay & Cable Spreading Room

   g. Battery Rooms

   h. Auxiliary Feed Pump Room

2. If Specification 3.14.E.1 cannot be met, within one hour hoses supplied from operable hose stations shall be made available for routing to each area with an inoperable hose station.

   Restore the inoperable hose station(s) to Operable status within 14 days or submit a 30-day written report outlining the cause of the inoperability and the plans and schedule for restoring the stations to Operable status.

F. Yard Hydrant Hose Houses

1. Whenever equipment in the following buildings is required to be operable, the yard hydrant hose houses in the main yard loop adjacent to each building shall be operable:

   a. Unit No. 1 Reactor Building

   b. Unit No. 2 Reactor Building

   c. Turbine Building

   d. Auxiliary Building

   e. Screen house

2. If Specification 3.14.F.1 cannot be met, within one hour have sufficient additional lengths of 2-1/2 inch diameter hose located in adjacent operable yard hydrant hose house(s) to provide service to the unprotected area(s).

   Restore the yard hydrant hose house(s) to Operable status within 14 days or submit a 30-day written report outlining the cause of the inoperability and the plans and schedule for restoring the houses to Operable status.

G. Penetration Fire Barriers

1. All penetration fire barriers in fire area boundaries protecting equipment required to be operable shall be operable.

2. If Specification 3.14.G.1 cannot be met, a continuous fire watch shall be established on at least one side of the affected penetration(s) within one hour.

   Restore the inoperable penetration fire barriers to Operable status within 14 days or submit a 30-day written report outlining the cause of the inoperability and the plans and schedule for restoring the barriers to Operable status.

Basis

Ionization, photoelectric, and thermal type fire detectors are located throughout safety related structures. These detectors sense the products of combustion during the very early stages of a fire or the heat emitted by a fire. The detectors in each area initiate an alarm in the control room. The specifications require a minimum number of detectors to be operable in each area. If this number is not operable, except for fire detectors located in primary containment, a patrolling fire watch is established in the affected area.

If an area is found to have an inoperable detector, the alarm for the affected zone may be bypassed while the detector is being repaired. Primary containment detectors are unique since (1) they are inaccessible during normal operation, and (2) no significant fire hazard exists inside containment during normal operation. Inoperable fire detectors located inside containment will be repaired during the first scheduled outage following discovery. Safety related fire detection instruments are listed in Table TS.3.14.1.

The fire suppression water system is supplied from the Mississippi River by two horizontal centrifugal fire pumps rated at 2000 gpm at 120 psig. One pump is motor driven and the other pump is diesel driven. A third pump also rated at 2000 gpm at 120 psig, is assigned to the screen wash system, and serves as a backup to the fire suppression water system. Header pressure is maintained between 108 and 113 psig by a jockey fire pump. If the water demand is such that the jockey pump cannot maintain the header pressure, the screen wash pump will start (if not running) and the screen wash to fire header bypass valve will open at 102 psig. The bypass line is orificed to restrict flow to 450 gpm. On further demand, the motor driven fire pump will automatically start at 95 psig. If further demand of water is called for and the header pressure drops to 90 psig, the diesel driven fire pump will start. Pumps are designed to pump 2000 gpm and maintain a minimum of 65 psig in the fire header, measured at the highest point in the system. The screen wash pump may be directly aligned to the fire header by manual action from the control room. Any one fire pump, or the screen wash pump, can be used to supply all fire fighting water requirements. In the event that a pump is inoperable, up to seven days are allowed to restore the pump to operability or a report must be submitted to the Commission explaining the circumstances. If all pumps are inoperable, or if the fire suppression water system is incapable of supplying water to a safety related area, a backup fire suppression water system must be established within 24 hours and the Commission must be informed.

The cooling water system, also supplied by the Mississippi River, provides additional redundancy to the fire suppression water system. Crossover water supplies from the cooling water system to the fire protection system are provided for the safety related areas.

Basis (continued)

Water deluge or wet pipe sprinkler systems are provided in safety related areas where a significant fire hazard exists, except for the relay and cable spreading room. Due to the nature of the equipment in the relay and cable spreading area, a carbon dioxide system is provided. Whenever a deluge or sprinkler system is inoperable, a continuous fire watch with backup fire suppression equipment available is stationed in the area until operability is restored. Whenever the relay and cable spreading room carbon dioxide systems become inoperable, up to 14 days are allowed to complete maintenance. If the system cannot be restored to operable status within this time period, a report outlining the situation is submitted to the Commission. Whenever the carbon dioxide system is inoperable, a continuous fire watch with backup fire suppression equipment is stationed in the room. Since the relay and cable spreading area is occupied during normal working hours, the automatic initiation feature of the CO_2 system is bypassed during this period and whenever entry is made during other times. The system is initiated manually in the event fire is detected when the room is occupied.

In addition to deluge and sprinkler systems, hydrant hose houses are located in the yard and hose stations are located throughout the plant. These hose stations provided primary and backup protection for safety related systems and components. Normally all yard hydrant hose houses and hose stations are operable when a reactor is above cold shutdown. If a hose house or station protecting safety related equipment becomes inoperable, additional hose must be available for routing to the unprotected area. This hose may be supplied from an operable hydrant hose house, hose station, or brigade locker.

Piping and electrical penetrations are provided with seals where required by the fire severity. If a seal is made or found to be inoperable for any reason, the penetration area is continuously attended until an effective fire seal is restored. Seals have been qualified for the maximum fire severity present on either side of the barrier.

TABLE TS.3.14-1
SAFETY RELATED FIRE DETECTION INSTRUMENTS

ZONE NO.	LOCATION	TYPE OF DETECTOR	MINIMUM NO REQUIRED	TOTAL NO. INSTALLED
1	Battery Rooms	Ion	2	2
2	Air compressor & Auxiliary Feed Pump Area	Ion, Thermal	2 0	9 3
6	D-2 Diesel Generator Room	Ion, Flame	2 0	3 1
8	Auxiliary Building, Unit No. 1, Ground Floor	Ion, Smoke Thermal	10 0 0	46 1 2
10	Reactor Building, Unit No. 1, Ground Floor	Ion, Smoke	2 0	18 1
11	Bus 15 & 16 Switch-gear Rooms	Ion	2	6
12	Relay & Cable Spreading Room	Ion	8	17
14	Computer Room	Ion	2	4
19	Auxiliary Building, Unit No. 1, Mezzanine	Ion	5	31
20	Reactor Building, Unit No. 1, Mezzanine	Ion	4	15
21	Reactor Building, Unit No. 1, Annulus Mezzanine	Ion, Flame	2 0	12 4
26	Bus 110 & 120 Switch-gear Rooms	Ion	2	2
28	Auxiliary Building, Unit No. 1, Operating Floor	Ion	2	15
29	Reactor Building, Unit No. 1, Operating Floor	Ion	2	14

TABLE TS.3.14-1 (CONTINUED)

SAFETY RELATED FIRE DETECTION INSTRUMENTS

ZONE NO.	LOCATION	TYPE OF DETECTOR	MINIMUM NO REQUIRED	TOTAL NO. INSTALLED
30	Auxiliary Building, Unit No. 1, Fan Deck	Ion	7	28
31	Control Room Chiller Unit Room	Ion	2	6
32	Reactor Building, Unit No. 1, Fan Floor	Ion	2	4
33	Spent Fuel Handling Area	Ion	4	13
35	Battery Rooms	Ion	2	2
40	Auxiliary Building, Unit No. 2, Ground Floor	Ion	5	14
42	Reactor Building, Unit No. 2, Ground Floor	Ion, Smoke	2 0	16 1
43	Bus 25 & 26 Switchgear Rooms	Ion	2	6
46	Auxiliary Building, Unit No. 2, Mezzanine	Ion	5	22
47	Reactor Building, Unit No. 2, Annulus, Mezzanine	Ion Flame	2 0	12 4
50	Bus 210 & 220 Switchgear Rooms	Ion	2	2
51	Auxiliary Building Unit No. 2, Operating Floor	Ion	1	10
52	Reactor Building, Unit No. 2, Operating Floor	Ion	3	14
53	Auxiliary Building, Unit No. 2, Fan Deck	Ion	3	23
54	Reactor Building, Unit No. 2, Fan Deck	Ion	2	4
56	Reactor Building, Unit No. 2, Mezzanine	Ion	4	15

TABLE TS.3.14-1 (pg 3 of 3)

ZONE NO.	LOCATION	TYPE OF DETECTOR	MINIMUM NO REQUIRED	TOTAL NO. INSTALLED
57	Control Room	Ion	7	30
74	Screenhouse, Ground Floor	Ion	1	11
75	Screenhouse, Operating Floor	Ion	2	20
82	D-1 Diesel Generator Room	Ion, Flame	2 0	3 1

TABLE TS.4.1-1
(Page 1 of 5)

MINIMUM FREQUENCIES FOR CHECKS, CALIBRATIONS AND TEST OF INSTRUMENT CHANNELS

	Channel Description	Check	Calibrate	Functional Test	Response Test	Remarks
1.	Nuclear Power Range	S(1) M(4)	D(2) Q(4)	M(3) M(5) M(6) M(7)	R	1) Once/shift when in service 2) Heat balance 3) Signal to ΔT; bistable action (permissive, rod stop, trips), with the exception of the items covered in Remark #7. 4) Upper and lower chambers for axial off-set using in-core detectors 5) Simulated signal for testing positive and negative rate bistable action 6) Quadrant Power Tilt Monitor 7) P8 and P10 permissives and the 25% High Flux Low Setpoint Trip.
2.	Nuclear Intermediate Range	*S(1)	NA	T(2)	R	1) Once/shift when in service 2) Log Level; bistable action (permissive, rod stop, trips)
3.	Nuclear Source Range	*S(1)	NA	T(2)	R	1) Once/shift when in service 2) Bistable action (alarm, trips)
4.	Reactor Coolant Temperature	S(1,2)	R(1,2,3)	M(1) M(2) T(3)	R(1) R(2)	1) Overtemperature ΔT 2) Overpower ΔT 3) Control Rod Bank Insertion Limit Monitor
5.	Reactor Coolant Flow	S	R	M	NA	
6.	Pressurizer Water Level	S	R	M	NA	
7.	Pressurizer Pressure	S	R	M	NA	

TABLE TS.4.1-1
(Page 5 of 5)

	Channel Description	Check	Calibrate	Functional Test	Response Test	Remarks
35.	Event Monitoring Instrumentation	M	R	NA	NA	Includes all those in FSAR Table 7.7-2 and Table TS.3.15-1 not included elsewhere in this Table
36.	Steam Exclusion Actuation System	W	R	M	NA	See FSAR Appendix I, Section I.14.6
37.	Pressurizer PORV Control	NA	R	M	NA	Instrument Channels for PORV Control Including Overpressure Mitigation System
38.	Degraded Voltage 4KV Safeguard Busses	NA	R	M	NA	
39.	Loss of Voltage 4KV Safeguard Busses	NA	R	M	NA	

S - Each Shift
D - Daily
W - Weekly
M - Monthly
Q - Quarterly
R - Each refueling shutdown
P - Prior to each startup if not done previous week
T - Prior to each startup following shutdown in excess of 2 days if not done in the previous 30 days
NA - Not Applicable
* - See Specification 4.1.D

MINIMUM FREQUENCIES FOR EQUIPMENT TESTS

		Test	Frequency	FSAR Section Reference
1.	Control Rod Assemblies	Rod drop times of full length rods	All rods during each refueling shutdown or following each removal of the reactor vessel head; affected rods following maintenance on or modification to the control rod drive system which could affect performance of those specific rods	7
1a.	Reactor Trip Breakers	Open trip	Monthly	-
2.	Control Rod Assemblies	Partial movement of all rods	Every 2 weeks	7
3.	Pressurizer Safety Valves	Set point	Each refueling shutdown	4
4.	Main Steam Safety Valves	Set point	Each refueling shutdown	10
5.	Reactor Cavity	Water level	Prior to moving fuel assemblies or control rods and at least once every day while the cavity is flooded.	-
6.	Pressurizer PORV Block Valves	Functional	Quarterly	-
7.	Pressurizer PORV's	Functional	Every 18 months	-
8.	(Deleted)			
9.	Primary System Leakage	Evaluate	Daily	4
10.	(Deleted)			
11.	Turbine stop valves, governor valves, and intercept valves. (Part of turbine overspeed protection.)	Functional	Monthly	10
12.	(Deleted)			

B. Emergency Charcoal Filter Systems

1. Periodic tests of the shield building ventilation system shall be performed at quarterly intervals to demonstrate operability. Each redundant train shall be initiated from the control room and determined to be operable at the time of its periodic test if it meets drawdown performance computed for the test conditions with 75% of the shield building inleakage specified in Figure TS 4.4-1 after initiation.

2. Periodic tests of the auxiliary building special ventilation system shall be performed at approximately quarterly intervals to demonstrate its operability. Each redundant train shall be initiated from the control room and determined to be operable at the time of periodic test if it isolates the normal ventilation system and produces a measureable negative pressure in the ABSVZ within 6 minutes after initiation.

3. At least once per operating cycle, or once each 18 months, whichever comes first, tests of the filter units in the Shield Building Ventilation System and the Auxiliary Building Special Ventilation System shall be performed as indicated below:

   a. The pressure drop across the combined HEPA filters and the charcoal adsorbers shall be demonstrated to be less than 6 inches of water at system design flow rate (±10%).

   b. The inlet heaters and associated controls for each train shall be determined to be operable.

   c. Verify that each train of each ventilation system automatically starts on a simulated signal of safety injection and high radiation (Auxiliary Building Special Ventilation only).

4. a. The tests of Specification 3.6.E.2 shall be performed at least once per operating cycle, or once every 18 months whichever occurs first, or after every 720 hours of system operation or following painting, fire or chemical release in any ventilation zone communicating with the system that could contaminate the HEPA filters or charcoal adsorbers.

3. Containment Fan Coolers

Each fan cooler unit shall be tested during each reactor refueling shutdown to verify proper operation of all essential features including low motor speed, cooling water valves, and normal ventilation system dampers. Individual unit performance will be monitored by observing the terminal temperatures of the fan coil unit and by verifying a cooling water flow rate of greater than or equal to 900 gpm to each fan coil unit.

4. Component Cooling Water System

   a. System tests shall be performed during each reactor refueling shutdown. Operation of the system will be initiated by tripping the actuation instrumentation.

   b. The test will be considered satisfactory if control board indication and visual observations indicate that all components have operated satisfactorily.

5. Cooling Water System

   a. System tests shall be performed at each refueling shutdown. Tests shall consist of an automatic start of each diesel engine and automatic operation of valves required to mitigate accidents including those valves that isolate non-essential equipment from the system. Operation of the system will be initiated by a simulated accident signal to the actuation instrumentation. The tests will be considered satisfactory if control board indication and visual observations indicate that all components have operated satisfactorily and if cooling water flow paths required for accident mitigation have been established.

   b. Each diesel engine shall be inspected at each refueling shutdown.

B. Component Tests

1. Pumps

   a. The safety injection pumps, residual heat removal pumps and containment spray pumps shall be started and operated at intervals of one month. Acceptable levels of performance shall be that the pumps start and reach their required developed heat on minimum recirculation flow and the control board indications and visual observations indicate that the pumps are operating properly for at least 15 minutes.

   b. A test consisting of a manually-initiated start of each diesel engine, and assumption of load within one minute, shall be conducted monthly.

h. Following completion of high head safety injection system or RHR system modifications that alter system flow characteristics a flow balance test shall be performed during shutdown to confirm the following injection flow rates are achieved:

1. High Head Safety Injection System:

(a) Flow through all four injection lines plus miniflow shall not exceed 835 gpm with one pump in operation.

(b) The minimum flow through loop A & B cold legs shall be 670 gpm with one pump in operation. The flow rates in each leg shall be within 20 gpm of each other with one pump in operation.

(c) Flow orifices and throttling valves will be used to limit and balance flow through the reactor vessel injection lines to a maximum of the total flow limit in Specification 4.5.B.3.h.1.(a) above, with one pump in operation. During this flow test the flow rates in each leg shall be within 50 gpm of each other.

2. RHR System:

The minimum flow through each RHR Reactor Vessel Injection line shall be at least 1800 gpm.

Basis

The Safety Injection System and the Containment Spray System are principal plant Safety Systems that are normally inoperative during reactor operation. Complete systems tests cannot be performed when the reactor is operating because a safety injection signal causes containment isolation and a Containment Spray System test requires the system to be temporarily disabled. The method of assuring operability of these systems is therefore to combine systems tests to be performed during refueling shutdowns, with more frequent component tests which can be performed during reactor operation.

The systems tests demonstrate proper automatic operation of the Safety Injection and Containment Spray Systems. With the pumps blocked from starting, a test signal is applied to initiate automatic action and verification made that the components receive the safety injection in the proper sequence. The test demonstrates the operation of the valves, pump circuit breakers, and automatic circuitry.

4.6 PERIODIC TESTING OF EMERGENCY POWER SYSTEM

Applicability

Applies to periodic testing and surveillance requirements of the emergency power system.

Objective

To verify that the emergency power sources and equipment are operable.

Specification

The following tests and surveillance shall be performed:

A. Diesel Generators

1. At least once each month, for each diesel generator:
   a. Verify the fuel level in the day and engine-mounted tank.
   b. Verify the fuel level in the fuel storage tank.
   c. Verify that a sample of diesel fuel from the fuel storage tank is within the acceptable limits specified in Table 1 of ASTM D975-68 when checked for viscosity, water, and sediment.
   d. Verify the fuel transfer pump can be started and transfers fuel from the storage system to the day tank.
   e. Verify the diesel starts from the normal standby condition.
   f. Verify the generator synchronizes, is loaded to at least 1375 kw, and operated for at least one hour.

2. At least once each 18 months:
   a. Subject each diesel generator to a thorough inspection in accordance with procedures prepared in conjunction with the manufacturer's recommendations for this class of standby service.
   b. For each unit, simulate a loss of offsite power in conjunction with a safety injection signal, and:
      1. Verify de-energization of the emergency busses and load shedding from the emergency busses.
      2. Verify the diesels start from the normal standby condition on the auto-start signal and energize the emergency busses in one minute.
      3. Verify that the diesel generator system trips, except those for engine overspeed, ground fault, and generator differential current, are automatically bypassed.
      4. Verify that the auto-connected loads do not exceed 3000 kw.
   c. Verify the capability of each generator to operate at least one hour while loaded to 3000 kw.
   d. Verify the capability of each generator to reject a load of at least 650 kw without tripping.
   e. During this test, operation of the emergency lighting system shall be ascertained.

b. The motor-driven fire pump shall be started every month and run for at least 15 minutes on recirculation flow.

c. The diesel-driven fire pump shall be started every month from ambient conditions and run for at least 20 minutes on recirculation flow.

d. The level in the diesel-driven fire pump fuel storage tank shall be checked every month and verified to contain at least 500 gallons of fuel.

e. Every three months verify that a sample of fuel from the diesel-driven fire pump fuel storage tank is within the acceptable limits specified in Table 1 of ASTM D975-68 when checked for viscosity, water and sediment.

f. Every 18 months subject the diesel-driven fire pump engine to an inspection in accordance with procedures prepared in conjunction with the manufacturer's recommendations for this class of standby service.

g. A simulated automatic actuation of each fire pump and the screen wash pump, including verification of pump capability, shall be conducted every 18 months.

h. The header system shall be flushed every 12 months.

i. System flow tests shall be performed every three years.

j. Valves in flow paths supplying fire suppression water to safety related structures, systems, and components shall be cycled every 12 months.

k. Each valve (manual, power operated, or automatic) in the flow path for safety-related areas and areas posing a fire hazard to safety-related areas, shall be verified to be in its correct position every month and the method of securing the valve in its correct position shall be verified every month.

2. When it is determined that one of the fire pumps required by specification 3.14.B.1.a is inoperable, the remaining operable pumps shall be run daily for at least 15 minutes (motor driven pumps) or 20 minutes (diesel driven pump) until specification 3.14.B.1.a can be met.

C. Spray and Sprinkler Systems

Each spray and sprinkler system specified in 3.14.C.1 shall be demonstrated operable by performing a nozzle inspection and system functional test, which includes simulated automatic actuation of the system, every 18 months.

D. Carbon Dioxide System

The relay and cable spreading room carbon dioxide system shall be demonstrated operable by the following actions:

1. Verify CO_2 storage tank level and pressure every week.
2. Verify that the system is operable by performing a system functional test which includes simulated automatic actuation of the system every 18 months and a puff test every three years.

E. Fire Hose Stations

The fire hose stations specified in 3.14.E.1 shall be demonstrated operable as follows:

1. Each month a visual inspection shall be conducted to assure all equipment is available.
2. Every 18 months the hose shall be removed for inspection and re-racking and all gaskets in the couplings shall be inspected and replaced if necessary.
3. Every three years, partially open each hose station valve to verify valve operability and no blockage.
4. Every three years each hose shall be hydrostatically tested at a pressure at least 50 psig greater than the maximum pressure available at that hose station.

F. Yard Hydrant Hose Houses

The yard hydrant hose houses specified in 3.14.F.1 shall be demonstrated operable as follows:

1. Each month a visual inspection shall be conducted of the yard hydrant hose houses to assure all required equipment is available.

2. Every six months (in the spring and fall) visually inspect each yard fire hydrant and verify that the hydrant barrel is dry and that the hydrant is not damaged.

3. Every year conduct a hose hydrostatic test at a pressure at least 50 psig greater than the maximum pressure available at any yard hydrant hose house and conduct an inspection of all gaskets in the couplings. All degraded gaskets shall be replaced.

G. Penetration Fire Barriers

Penetration fire barriers in fire area boundaries protecting safety related equipment shall be demonstrated operable as follows:

1. A visual inspection of fire barrier penetration fire barriers shall be conducted every 18 months.

2. Following repair or maintenance of a penetration fire barrier a visual inspection of the seal shall be conducted.

Basis

The minimum number of fire detectors required to be operable in each fire zone are functionally tested following the manufacturer's recommendations each six months, except for those located inside the primary containment which are tested during each cold shutdown exceeding 24 hours unless performed during the previous six months. These tests are performed by the plant staff. Other fire detectors will be tested at an interval which experience has shown to be necessary to assure reliable operation. Every six months an alarm circuit check is performed. This check can be performed in conjunction with detector functional tests. All circuitry is also provided with automatic supervision for opens and ground faults.

Fire pumps are tested each month to verify operability. Test starting of the screen wash pump is not required since it is normally in service. Each fire pump is manually started and operated for at least 15 or 20 minutes with pump flow directed through the recirculation test line. Every 18 months the operability of the automatic actuation logic for the fire pumps and the screen wash pump is verified and the performance of each pump is verified to meet system requirements. The specified flush and valve lineup check provide assurance that the piping system is capable of supplying fire suppression water to all safety related areas. When one of the pumps is inoperable the operable pumps are run daily to verify operability until all pumps are once again available.

Fire suppression water system flow tests will be done at least every three years to verify hydraulic performance. The testing will be performed using Section 11, Chapter 5 of the Fire Protection Handbook, 14th Edition, as a procedural guide. The test is generally performed in conjunction with insurance inspections.

Surveillance specified for each spray and sprinkler system is intended to assure that the systems will function as designed when they are needed. Functional tests are conducted at 18 month intervals on those systems provided with test facilities.

The testing specified for the relay and cable spreading room CO_2 system provides assurance that the CO_2 inventory is adequate to extinguish a fire in this area and that the system is capable of automatic actuation.

Hose stations and yard hydrant hose houses are inspected monthly to verify that all required equipment is in place. Gaskets in hose couplings are inspected periodically and the hose is pressure tested. Pressure testing of outdoor hose is conducted more frequently than indoor hose because of the less favorable storage conditions. Operability of hose station isolation valves is verified every three years by partially opening each valve to verify flow. All of these tests provide a high degree of assurance that each hose station will perform satisfactorily after periods of standby service.

Plant fire barrier walls are provided with seals for pipes and cables where necessary. Where such seals are installed, they must be maintained intact to perform their function. Visual inspection of each installed seal is required every 18 months and after seal repair. A visual inspection following repair of a seal in the secondary containment boundary is sufficient to assure that seal leakage will be within acceptable limits.

6.0 ADMINISTRATIVE CONTROLS

6.1 ORGANIZATION

A. The Plant Manager has the overall full-time onsite responsibility for safe operation of the facility. During periods when the Plant Manager is unavailable, he may delegate this responsibiliity to other qualified supervisory personnel.

B. The Northern States Power corporate organizational structure relating to the operation of this plant is shown on Figure TS.6.1-1.

C. The functional organization for operation of the plant shall be as shown in Figure TS.6.1-2 and:

1. Each on duty shift shall be composed of at least the minimum shift crew composition shown on Table TS.6.1-1.

2. For each reactor that contains fuel: a licensed operator in the control room.

3. At least two licensed operators shall be present in the control room during a reactor startup, a scheduled reactor shutdown, and during recovery from a reactor trip. These operators are in addition to those required for the other reactor.

4. An individual qualified in radiation protection procedures shall be on site when fuel is in a reactor.

5. All refueling operations shall be directly supervised by a licensed Senior Reactor Operator of Senior Reactor Operator Limited to Fuel Handling who has no other concurrent responsibilities during this operation.

6. A fire brigade of at least five members shall be maintained on site at all times.* The fire brigade shall not include the six members of the minimum shift crew for safe shutdown of the reactors.

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*Fire Brigade composition may be less than the minimum requirements for a period of time not to exceed 2 hours in order to accommodate unexpected absence of Fire Brigade members provided immediate action is taken to restore the Fire Brigade to within the minimum requirements.

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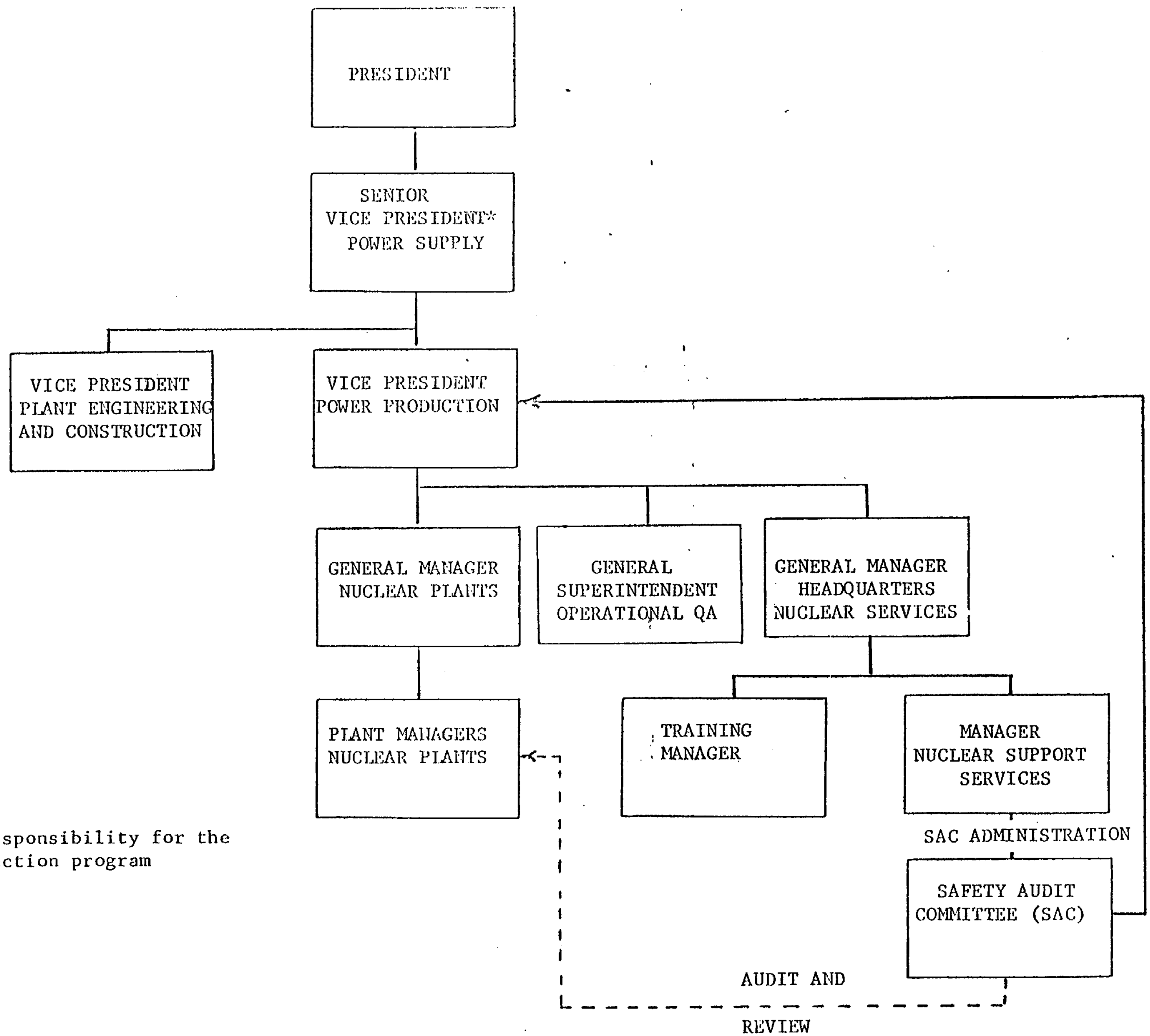
Prairie Island Unit 2 - Amendment No. ~~33~~, 43



* Has the responsibility for the fire protection program

FIGURE TS.6.1-1 NSP CORPORATE ORGANIZATIONAL RELATIONSHIP TO ON-SITE OPERATING ORGANIZATION

FIGURE TS.6.1-1

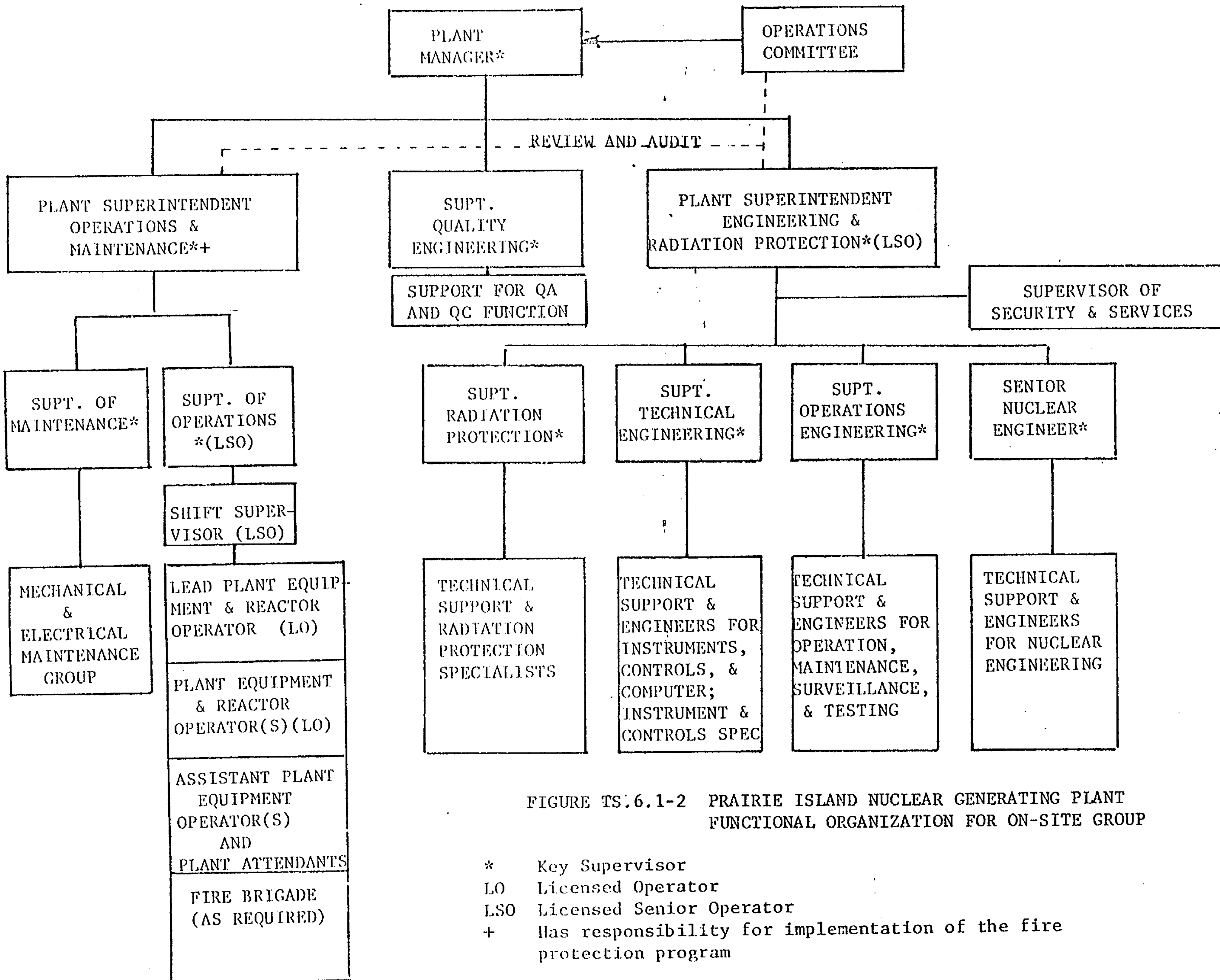


FIGURE TS.6.1-2 PRAIRIE ISLAND NUCLEAR GENERATING PLANT
FUNCTIONAL ORGANIZATION FOR ON-SITE GROUP

*	Key Supervisor
LO	Licensed Operator
LSO	Licensed Senior Operator
+	Has responsibility for implementation of the fire protection program

6.2 Review and Audit

Organizational units for the review and audit of facility operations shall be constituted and have the responsibilities and authorities outlined below:

A. Safety Audit Committee (SAC)

The Safety Audit Committee provides the independent review of plant operations from a nuclear safety standpoint. Audits of plant operation are conducted under the cognizance of the SAC.

1. Membership

   a. The SAC shall consist of at least five (5) persons.

   b. The SAC chairman shall be an NSP representative, not having line responsibility for plant operation, appointed by the Vice President - Power Production. Other SAC members shall be appointed by the Vice President - Power Production or by such other person as he may designate. The Chairman shall appoint a Vice Chairman from the SAC membership to act in his absence.

   c. No more than two members of the SAC shall be from groups holding line responsibility for operation of the plant.

   d. A SAC member may appoint an alternate to serve in his absence, with concurrence of the Chairman. No more than one alternate shall serve on the SAC at any one time. The alternate member shall have voting rights.

2. Qualifications

   a. The SAC members should collectively have the capability required to review activities in the following areas: nuclear power plant operations, nuclear engineering, chemistry and radiochemistry, metallurgy, instrumentation and control, radiological safety, mechanical and electrical engineering, quality assurance practices, and other appropriate fields associated with the unique characteristics of the nuclear power plant.

f. Investigation of all events which are required by regulation or technical specifications (Appendix A) to be reported to NRC in writing within 24 hours.

g. Revisions to the Facility Emergency Plan, Facility Security Plan, and the Fire Protection Program.

h. Operations Committee minutes to determine if matters considered by that Committee involve unreviewed or unresolved safety questions.

i. Other nuclear safety matters referred to the SAC by the Operations Committee, plant management or company management.

j. All recognized indications of an unanticipated deficiency in some aspect of design or operation of safety-related structures systems, or components.

k. Reports of special inspections and audits conducted in accordance with specification 6.3.

6. Audit - The operation of the nuclear power plant shall be audited formally under the cognizance of the SAC to assure safe facility operation.

   a. Audits of selected aspects of plant operation, as delineated in Paragraph 4.4 of ANSI N18.7-1972, shall be performed with a frequency commensurate with their nuclear safety significance and in a manner to assure that an audit of all nuclear safety-related activities is completed within a period of two years. The audits shall be performed in accordance with appropriate written instructions and procedures.

   b. Periodic review of the audit program should be performed by the SAC at least twice a year to assure its adequacy.

   c. Written reports of the audits shall be reviewed by the Vice President - Power Production, by the SAC at a scheduled meeting, and by members of management having responsibility in the areas audited.

7. Authority

   The SAC shall be advisory to the Vice President - Power Production.

8. Records

   Minutes shall be prepared and retained for all scheduled meetings of the Safety Audit Committee. The minutes shall be distributed within one month of the meeting to the Vice President - Power Production, the General Manager, Nuclear Plants each member of the SAC and others designated by the Chairman. There shall be a formal approval of the minutes.

B. Operations Committee (OC)

1. Membership

The Operations Committee shall consist of at least six (6) members drawn from the key supervisors of the onsite staff. The Plant Manager shall serve as Chairman of the OC and shall appoint a Vice Chairman from the OC membership to act in his absence.

2. Meeting Frequency

The Operations Committee will meet on call by the Chairman or as requested by individual members and at least monthly.

3. Quorum

A majority of the permanent members, including the Chairman or Vice Chairman

4. Responsibilities - The following subjects shall be reviewed by the Operations Committee:

a. Proposed tests and experiments and their results.

b. Modifications to plant systems or equipment as described in the Final Safety Analysis Report and having nuclear safety significance or which involve an unreviewed safety question as defined in Paragraph 50.59 (c), Part 50, Title 10, Code of Federal Regulations.

c. Proposals which would effect permanent changes to normal and emergency operating procedures and any other proposed changes or procedures that will affect nuclear safety as determined by the Plant Manager.

d. Proposed changes to the Technical Specifications or operating licenses.

e. All reported or suspected violations of Technical Specifications, operating license requirements, administrative procedures, operating procedures. Results of investigations, including evaluation and recommendations to prevent recurrence will be reported in writing to the General Manager - Nuclear Plants and to the Chairman of the Safety Audit Committee.

f. All events which are required by regulations or Technical Specifications to be reported to the NRC in writing within 24 hours.

g. Drills on emergency procedures (including plant evacuation) and adequacy of communication with offsite support groups.

h. All procedures required by these Technical Specifications, including implementing procedures of the Emergency Plan, and the Security Plan, shall be reviewed initially and periodically with a frequency commensurate with their safety significance but at an interval of not more than two years.

i. Special reviews and investigations, as requested by the Safety Audit Committee.

5. Authority

The OC shall be advisory to the Plant Manager. In the event of a disagreement between the recommendations of the OC and the Plant Manager, the course determined by the Plant Manager to be the more conservative will be followed. A written summary of the disagreement will be sent to the General Manager and the Chairman of the SAC for review.

6. Records

Minutes shall be recorded for all meetings of the OC and shall identify all documentary material reviewed. The minutes shall be distributed to each member of the OC, the Chairman and each member of the Safety Audit Committe, the General Manager Nuclear Plants and others designated by the OC Chairman or Vice Chairman.

7. Procedures

A written charter for the OC shall be prepared that contains:

a. Responsibility and authority of the group

b. Content and method of submission of presentations to the Operations Committee

c. Mechanism for scheduling meetings

d. Provision for meeting agenda

6.4 SAFETY LIMIT VIOLATION

If a safety limit is exceeded, the reactor shall be shut down and the Commission shall be notified immediately. It shall also be promptly reported to the General Manager Nuclear Plants and the Chairman of the Safety Audit Committee, or their designated alternates. A safety limit violation report shall be prepared. This report shall describe (1) applicable circumstances preceding the violation, (2) effects of the violation upon facility components, systems or structures, and (3) the basis for corrective action taken to preclude recurrence. The report shall be reviewed by the Operations Committee. The safety limit violation report shall be submitted to the Commission, the General Manager Nuclear Plants and the Safety Audit Committee within two weeks of the event.

Operation shall not be resumed until authorized by the Nuclear Regulatory Commission.

1. a. Paragraph 20.203 "Caution signs, labels, signals and controls". In lieu of the "Control device" or alarm signal required by paragraph 20.203(c)(2), each high radiation area in which the intensity of radiation is 1000 mRem/hr or less shall be barricaded and conspicuously posted as a high radiation area and entrance thereto shall be controlled by requiring issuance of a Radiation Work Permit (or continuous escort by a qualified person for the purpose of making a radiation survey) and any individual or group of individuals permitted to enter such areas shall be provided with a radiation monitoring device which continuously indicates the radiation dose rate in the area.

   b. The above procedure shall also apply to each high radiation area in which the intensity of radiation is greater than 1000 mRem/hr, except that doors shall be locked or attended to prevent unauthorized entry into these areas and the keys or key devices for locked doors shall be maintained under the administrative control of the Plant Manager.

2. A program shall be implemented to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. This program shall include the following:

   a. Provisions establishing preventive maintenance and periodic visual inspection requirements, and

   b. Integrated leak test requirements for each system at a frequency not to exceed refueling cycle intervals.

   A program acceptable to the Commission was described in letters from L O Mayer, NSP, to Director of Nuclear Reactor Regulation, dated December 31, 1979 "Lessons Learned Implementation" and March 13, 1980, "1/1/80 Lessons Learned Implementation Additional Information".

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

   a. Training of personnel,

   b. Procedures for monitoring, and

   d. Provisions for maintenance of sampling and analysis equipment.

   A program acceptable to the Commission was described in letters from L O Mayer, NSP, to Director of Nuclear Reactor Regulation, dated December 31, 1979 "Lessons Learned Implementation" and March 13, 1979, "1/1/80 Lessons Learned Implementation Additional Information".

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

SUPPORTING AMENDMENT NOS. 49 AND 43 TO FACILITY LICENSE NOS. DPR-42 AND DPR-60

NORTHERN STATES POWER COMPANY

PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNIT NOS. 1 AND 2

DOCKET NOS. 50-282 AND 50-306

Introduction:

By letter dated May 16, 1980 the Northern States Power Company (NSP) requested an amendment to Facility Operating License Nos. DPR-42 and DPR-60 for the Prairie Island Nuclear Generating Plant, Unit Nos. 1 and 2 (PINGP). The amendments requested changes to the Technical Specifications (TS) for the following subjects:

(1) To implement the protection from degraded grid voltage condition requirements (Millstone fixes).

(2) Emergency charcoal filter system test initiation signal.

(3) Containment Fan Coolers Design Performance Verification.

(4) RHR System Flow Requirements.

(5) Diesel generator surveillance.

(6) Safety related shock supressors.

(7) Miscellaneous corrections and clarifications.

(8) Organizational changes.

(9) Definition of Operability.

These matters are addressed as items 1 through 9 in the following report.

This safety evaluation also addresses the clarifications and correction of typographical errors previously contained in License Paragraph 2.C.(3) on physical protection programs and corrects omissions and typographical errors introduced as a result of previous changes in Amendments 46/40 and 47/41 to Sections 3.1 and 4.1. These matters are addressed as items 10 and 11 in the following report.

By letter dated February 20, 1980 the licensee requested amendments to Facility License Nos. DPR-42 and DPR-60 for the PINGP which would expand the control rod misalignment LCO's. This matter is addressed as item 12 in the following report.

By letter dated July 31, 1980 the licensee requested amendments to Facility License Nos. DPR-42 and DPR-60 for the PINGP which would provide additional LCO's and surveillance requirements for fire protection systems. This matter is addressed as item 13 in the following report.

Discussion:

Item 1 - As a result of an event at Millstone Unit No. 2 the NRC requested all utilities to investigate the vulnerability of each facility to similar degraded grid voltage conditions (Reference 1). NSP responded to this letter on September 20, 1976 (Reference 2). Further criteria and staff positions pertaining to degraded grid voltage protection were transmitted to NSP by NRC generic letter dated June 3, 1977 (Reference 3). In response to this, by letters dated May 4, 1978 and October 12, 1979, NSP proposed certain design modifications and changes to the TS. A detailed review and technical evaluation of these proposed modifications and changes was performed by the Lawrence Livermore Laboratory (LLL) under contract to the NRC, and with general supervision by NRC staff. This work was reported in LLL report UCID-18654, "Technical Evaluation of the Proposed Design Modifications and Technical Specification Changes on Grid Voltage Degradation for the Prairie Island Nuclear Generating Plant Units 1 and 2" dated March 1980 (attached).

Item 2 proposes changes to TS 4.4.B.1 and 4.4.B.2, Emergency Charcoal Filter Systems. Technical Specification 4.4.B requires testing of both the containment shield building ventilation system and the auxiliary building special ventilation system on a quarterly basis and on a once per operating cycle or once per 18 month basis. The proposed change to the TS would delete the requirement for the quarterly testing of these two systems to be initiated by a simulated safety injection signal and would allow manual initiation of these systems for the quarterly tests. The once per operating cycle or 18 month test of these systems would continue to be initiated by a simulated safety injection signal.

Item 3 would change Technical Specification 4.5.A.3, Containment Fan Coolers, to replace the test requirements now in the TS with a more representative requirement that would measure terminal temperatures of the fan coil unit and coolant flowrate through the unit for containment atmospheric conditions normally experienced during power operation.

Item 4 would revise TS 4.5.B.3.h.2 by deleting the words "with one pump in operation." The addition of these words was somewhat misleading since there are two RHR pumps, each of 1800 gpm or greater capacity, each discharging through its train's single reactor vessel injection line.

The change has no effect on safety or environmental impact. The provision of this clarification will enhance compliance with the surveillance requirement. Since this change is administrative in nature, it need not be evaluated further.

Item 5 would revise TS 4.6.A.2.b.3 to include a trip of the diesel generator on occurrence of a ground fault, as well as engine overspeed and generator differential current in the list of trips that are not automatically by-passed on receipt of a safety injection signal. The proposed change clarifies the TS to be consistent with the previously existing diesel generator design.

The change has no effect on safety or environmental impact. Since this change is administrative in nature it need not be evaluated further.

Item 6 would change TS Table T.S. 3.12-1 "Safety Related Shock Suppressors (Snubbers)" by adding additional shock suppressors to the list of suppressors categorized as safety related.

Item 7, subitems a through f, proposes changes which are administrative and clerical in nature. These include correction of typographical errors (b and c) and clarifications regarding radiation control procedures (e) and the plant functional organization (f). Items (a) and (b) have been accounted for in previous amendments to the license. These are administrative changes and need not be evaluated further.

Item 8- The proposed change in the corporate organizational structure would replace the six management positions from the Plant Manager to the President with five positions, adds a management position for quality assurance activities to the organization chart, adds a separate position for the management of training activities and adds positions for the offsite nuclear support group.

The proposed change in the on-site operating organization includes changing the Quality Engineer's position to Superintendant for Quality Engineering now reporting directly to the Plant Manager and other changes in titles for given positions which are otherwise unchanged.

Item 9 would change the TS to clarify the meaning of the term OPERABLE. By letter dated May 16, 1980 the licensee responded to the staff's letter of April 10, 1980 on this subject by proposing changes in the definition of OPERABLE contained in the PINGP TS.

Item 10- In Amendment Nos 45 and 39 to Facility License Nos DPR-42 and DPR-60 issued on February 25, 1981 we consolidated and updated information contained in the license on Physical Protection programs. The licensee has pointed out that the titles of the program documents referenced in Amendments 45 and 39 are not consistent with the titles of the program documents generated by the licensee and has also identified several typographical errors and omissions in Paragraph 2.C.(3). Therefore Paragraph 2.C.(3) of License Nos. DPR-42 and DPR-60 are restated to correct these items. This change has no effect on safety nor any environmental impact. Since this change is administrative in nature it need not be evaluated further.

Item 11 - In Amendment Nos 46 and 40 issued on March 2, 1981 we issued TS in response to the Three Mile Island Unit 2 accident assessment. In Amendment Nos 47 and 41 issued April 1, 1981 we issued TS in response to the decay heat removal capability and depth of water over the reactor vessel flange during refueling operations. The TS which were added by the earlier amendments were, in some instances, inadvertently deleted by the issuance of the later amendment. The pages involved are TS3.1-2, TS3.1-3, TS3.1-3A and 4.1-2A. These pages have been corrected to be consistent with both amendments 46/40 and 47/41 issued earlier. Since this change is administrative in nature it need not be evaluated further.

Item 12 - By letter to the licensee dated October 29, 1979 the staff stated that it had recently completed a review of the LER's and TS requirements related to Control Rod Position Indication Systems (RPI) at Westinghouse PWR's and had determined that a wide variation existed in the number of LER's reviewed and the TS requirements and had therefore decided to clarify the regulatory requirements. By letter dated February 20, 1980 the licensee responded to the staff's earlier letter with a proposed change to the PINGP TS.

Item 13 - In the Safety Evaluation Report accompanying the issuance of Amendment Nos. 39 and 33 on September 6, 1979 the staff noted that following implementation of certain modifications of the fire protection system it would be necessary to further modify the TS to incorporate the LCO's and surveillance requirements for these modifications. By letter dated July 31, 1980 the licensee submitted proposed changes to the TS for some of these modifications. The proposal also corrected certain typographical errors.

Evaluation:

Degraded Grid Voltage Conditions

Item 1 - In response to the degraded grid voltage concern, the following design modifications and Technical Specification changes were proposed and implemented by NSP:

a. Installation of second level undervoltage relays, two on each of the four 4160v Class 1E buses with a drop out setting at approximately 90% of nominal bus voltage and a six second time delay. These relays will be part of a modified two-out-of-four coincidence logic scheme. The same logic is used for the existing first level of undervoltage protection. The LLL initial evaluation was based on an NSP preliminary setpoint proposal of 89% $\pm$ 1%. Following further evaluation by NSP a setpoint of 90% $\pm$ 2% was proposed in the TS submittal. This is a more conservative accounting for anticipated instrument drift and is acceptable.

b. Installation of circuitry to block the undervoltage trip load shedding feature on the 4160v Class 1E buses when the diesel generators are supplying these buses, and automatically reinstating this feature when the diesel generator breakers are tripped.

c. Addition of trip setpoint, limiting conditions for operation and surveillance requirements in the Technical Specifications associated with the design modifications cited above.

The criteria used by LLL in its technical evaluation of the above proposed changes include GDC-17, "Electric Power Systems," of Appendix A to 10 CFR 50; IEEE Standard 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations;" IEEE Standard 308-1974, "Class 1E Power Systems for Nuclear Power Generating Stations;" and the staff positions defined in NRC generic letter to NSP dated June 3, 1977.

We have reviewed the LLL Technical Evaluation Report and concur in its findings that (1) the proposed modifications will protect the Class 1E Equipment and systems from a sustained degraded voltage of the offsite power source, and (2) the proposed changes to the TS meet the criteria for periodic testing of protection systems and equipment. Therefore, we conclude that NSP's proposed design modifications and changes to the TS are acceptable.

TS 4.4.B Emergency Charcoal Filter Systems

Item 2 - NSP proposes to change the quarterly surveillance test initiation signals for the containment shield building ventilation system and the auxiliary building special ventilation system from a simulated safety injection signal to a manual initiation signal. The TS changes make the testing requirements for these two systems consistent with the quarterly testing requirements specified for other PINGP safety related systems. The revised testing requirements have also been modified slightly by us with the licensee's concurrence such that they are also consistent with comparable testing requirements included in the Standard Technical Specifications. We have reviewed the proposed changes as modified and find that they are acceptable.

Item 3 - TS 4.5.A.3, Containment Fan Coolers

TS 4.5.A.3 now requires that containment cooling fan coil unit performance be determined to be within design specifications (i.e. performance requirements consistent with the mode of operation following an accident) during each refueling. The requested change would replace the requirement to determine that unit performance is within design specification with a requirement to demonstrate acceptable fan coil unit terminal coolant temperatures and coolant flowrate for containment atmospheric conditions normally experienced during power operations.

It is not possible to demonstrate fan coil unit heat removal capabilities consistent with the design specifications because of the much reduced thermal loading on the fan coil unit from the containment atmospheric conditions experienced during normal operating modes relative to the steam environment of elevated temperature and pressures associated with an accident. Sufficient assurance of the operability of the fan coil units will be provided by the revised specification which requires the measurement of fan coil unit terminal temperatures and the measurement of fan coil coolant flow rate for comparison against a specified value.

Based on our review, the revised TS is consistent with the NRC staff Standard Technical Specifications and is acceptable.

Item 6 - TS Table TS 3.12-1 "Safety Related Shock Suppressors (Snubbers)"

TS Table TS 3.12-1 now includes only shock suppressors for systems defined by the FSAR analyses to be essential in the analysis of high energy line break events. The requested change would expand the list of suppressors which must be determined to be operable to assure safe operation to include all suppressors required to protect systems required to safely shutdown and maintain the reactor in a safe shutdown condition. We have concluded that the proposed change increases the protection provided to safety related systems from seismic events and is acceptable.

Item 8 - TS Section 6.0, Administrative Controls

We have evaluated the proposed changes in the licensee's corporate organizational relationship to the on-site operating organization and conclude that the changes are likely to provide more visability for the management of quality assurance activities and for the management of training activities and reflect a strengthening of the offsite support groups for the licensee's nuclear plants and are therefore acceptable.

We have evaluated the proposed changes in the licensee's on-site group and conclude that the changes are likely to provide more visability for the management of quality assurance activities. The proposed changes in titles for the same positions involve insignificant changes in responsibilities and functions. Therefore, we find these changes acceptable.

Item 9 - TS 1.I, Operable

The guidance provided in the staff's letter of April 10, 1980 is based on the consideration that (a) the Limiting Conditions for Operation (LCO's) specified for the plant safety related systems address, in most cases, only single outages of components, trains or subsystems, and (b) for any particular system the LCO does not address multiple outages of redundant components nor does it address the effects of outages of any support system. Therefore the NRC staff's April 10, 1980 letter requested the licensee to incorporate two general types of specifications to assure that no set of equipment outages would be allowed to persist that would result in the facility being in an unprotected condition.

One type of general specification specifies the corrective measures to be taken for circumstances in excess of those addressed in the specific system specification. Addition of this specification was intended to provide for the situation wherein a specific system specification addresses the action required to deal with one inoperable component, train or subsystem but does not address the action required wherein further components, trains or subsystems redundant to the first one above are also inoperable. The licensee addressed this subject further in a letter dated May 14, 1980 wherein he stated that since the PINGP TS have specific action statements and plant operating modes requirements integrated with the LCO's for each safety system, it would not be practical to include further STS requirements in this regard in the PINGP TS. We have reviewed the PINGP TS and find that for TS which address redundant components, trains or subsystems the TS require that all redundant components, trains or subsystems (CTS) be operable except for a single CTS which may be inoperable for a specified time. The PINGP TS also explicitly require that the operability of the redundant CTS be demonstrated prior to initiating corrective action on the inoperable CTS. Based on these considerations we conclude that the PINGP TS do not require further modifications to meet the objectives of the staff's model STS in this regard and are acceptable.

The second type of general specification addresses the situation for which a system would be declared inoperable solely because its emergency power source is inoperable. We have reviewed the licensee's proposed addition of general specifications in this regard and have determined that when implemented in conjunction with the overall PINGP TS they meet the objectives of the Model STS and are acceptable.

Item 12 - Technical Specification 3.10.E, Rod Misalignment Limitations

Westinghouse has performed safety analyses for control rod misalignment up to 15 inches or 24 steps (one step equals 5/8 inch). Since analyses of misalignments in excess of this amount have not been submitted, we have determined that a LCO restricting continued operation with a misalignment in excess of 15 inches is appropriate. Because the analog control rod position indication system has an uncertainty of 7.5 inches (12 steps), when an indicated deviation of 12 steps exists, the actual misalignment may be 15 inches. This is because one of the coils, spaced at 3.75 inches, may be failed without the operator's knowledge. The Standard Technical Specifications were written to eliminate any confusion about this, and restrict deviations to 12 indicated steps. Surveillance requirements, on the indication accuracy of 12 steps, were also prepared to ensure that the 15 inch LCO is met. Since there is no difference intended in requirements issued for any Westinghouse reactor, plants with Technical Specifications written in different terms of misalignment should consider the 12 step instrument inaccuracy when monitoring rod position.

A related problem is that the installed analog control rod position indicating system equipment may not, in some areas, be adequate to maintain the control rod misalignment specification requirement because of drift problems in the calibration curves. This is evidenced by numerous LER's concerning rod position indication accuracy. In these cases, the uncertainty may be more than 12 steps.

The licensee was requested by letter dated October 29, 1979 to review the TS for the PINGP to ensure that the control rods are required to be maintained with ± 12 steps indicated position and that the rod position indication system is accurate to within ± 12 steps.

By letter dated February 20, 1980, the licensee responded to the NRC request and provided proposed TS to address the staff's concerns. The proposed change differs from the staff's model by allowing misalignments up to 15 inches (24 steps) when the rods are positioned less than 30 steps or greater than 215 steps. Since the reactivity worths of control rods at positions less than 30 steps or greater than 215 steps are sufficiently small that misalignments up to 15 inches (24 steps) will have no appreciable effect on in-core power distribution and since calibrations are performed for the normal operation region of between 20 and 210 steps, the staff finds this difference with the model TS to be acceptable.

Based on our review of the licensee's submittal, we find that the proposed changes are in conformance with the staff's request and are, therefore, acceptable.

Item 13 - TS 3.14 and 4.16, Fire Detection and Protection Systems

With the issuance of Amendment Nos. 39 and 33 on September 6, 1979 the staff stated in the accompanying Fire Protection Safety Evaluation Report (FPSER) that following the implementation of certain modifications of the fire protection systems the Technical Specifications would be further modified to incorporate the applicable LCO's and surveillance requirements for these modifications. In a submittal dated July 31, 1980 the licensee proposed further modifications of this type. The licensee also proposed modifications to clarify the wording and to correct several typographical errors.

We find that the proposed specifications are in addition to fire protection system technical specifications previously established, will not adversely affect the effectiveness of the plant's fire protection program and are generally worded consistent with the Standard Technical Specifications. On these bases we conclude that the proposed changes are acceptable.

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 or negative declaration and environmental impact appraisal need not be prepared in connection with the issuance of these amendments.

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 these amendments will not be inimical to the common defense and security or to the health and safety of the public.

Date: July 28, 1981

Attachments to SER:
1. References
2. Technical Evaluation Report by
   Lawrence Livermore Laboratory, UCID-18654

Attachment 1

REFERENCES

1. NRC description of degraded grid voltage condition, D. L. Ziemann to L. O. Mayer, August 13, 1976.

2. NSP response to degraded grid voltage condition, L. O. Mayer to D. L. Ziemann, September 20, 1976.

3. NRC request on degraded grid voltage condition, D. K. Davis to L. O. Mayer, June 3, 1977.

4. NSP response on degraded grid voltage condition, L. O. Mayer to Director, NRR, May 4, 1978.

5. NRC request on degraded grid voltage condition A. Schwencer to L. O. Mayer, July 30, 1979.

6. NSP response on degraded grid voltage condition, L. O. Mayer to Director, NRR, October 12, 1979.

7. NSP submittal of proposed Technical Specification changes, L. O. Mayer to Director, NRR, May 16, 1980.

8. NSP submittal of Supplement No. 1 to proposed TS changes, L. O. Mayer to Director, NRR, October 8, 1980.

9. NRC letter, D. G. Eisenhut, to all licensees dated April 10, 1980.

Attachment 2

UCID- 18654

TECHNICAL EVALUATION OF THE PROPOSED DESIGN MODIFICATIONS AND TECHNICAL SPECIFICATION CHANGES ON GRID VOLTAGE DEGRADATION FOR THE PRAIRIE ISLAND NUCLEAR GENERATING PLANT UNITS 1 AND 2

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March 1980

Lawrence Livermore Laboratory

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ABSTRACT

This report documents the technical evaluation of the proposed design modifications and technical specification changes on grid voltage degradation for the Prairie Island Nuclear Generating Plant. The review criteria are based on IEEE Std-279-1971, IEEE Std-308-1974, and General Design Criterion 17 of the Code of Federal Regulations, Title 10, part 50, Appendix A requirements for determining the acceptability of the proposed system to protect the safety-related equipment from degradation of grid voltages.

FOREWORD

This report is supplied as part of the Selected Electrical, Instrumentation, and Control Systems Issues (SEICSI) Program being conducted for the U. S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Division of Operating Reactors, by Lawrence Livermore Laboratory, Field Test Systems Division of the Electronics Engineering Department.

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TECHNICAL EVALUATION OF THE PROPOSED DESIGN MODIFICATIONS AND TECHNICAL SPECIFICATION CHANGES ON GRID VOLTAGE DEGRADATION FOR THE PRAIRIE ISLAND NUCLEAR GENERATING PLANT UNITS 1 AND 2

(Docket Nos. 50-282, 50-306)

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1. INTRODUCTION

By letter dated June 3, 1977 [Ref. 1], the U.S. Nuclear Regulatory Commission (NRC) requested the Northern States Power Company to assess the susceptibility of the Prairie Island Nuclear Generating Plant Class 1E electrical equipment to sustained degraded voltage conditions at offsite power sources and to the interaction between the offsite and onsite emergency power system. In addition, the NRC requested that the licensee compare the current design of the emergency power systems at the plant facilities with the NRC staff positions, as stated in the June 3, 1977 letter [Ref. 1], and that the licensee propose plant modifications, as necessary, to meet the NRC staff positions or provide a detailed analysis which shows that the facility design has equivalent capabilities and protection features. Further, the NRC required certain Technical Specifications be incorporated into all facility operating licenses.

2. DESIGN BASIS CRITERIA

The design basis criteria that were applied in determining the acceptability of the system modification to protect the Class 1E equipment from degradation of grid voltages are as follows:

(1) General Design Criterion 17 (GDC 17), "Electric Power Systems," of Appendix A, "General Design Criteria for Nuclear Power Plants," in the Code 3 of Federal Regulations, Title 10, part 50 (10 CFR 50) [Ref. 4].

(2) IEEE Std-279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations" [Ref. 5].

(3) IEEE Std-308-1974, "Class 1E Power Systems for Nuclear Power Generating Stations" [Ref. 6].

(4) NRC positions as stated in a letter dated June 3, 1977 [Ref. 1].

3. EVALUATION

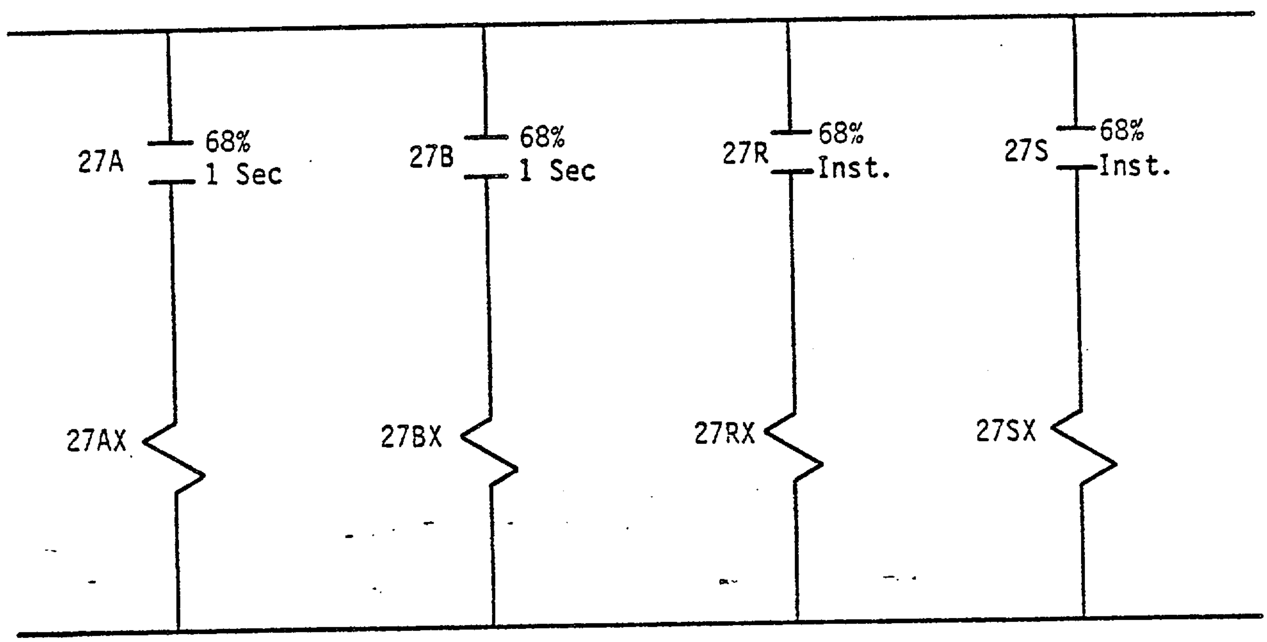
3.1 EXISTING UNDERVOLTAGE PROTECTION

The present design uses undervoltage relays to sense the loss of offsite power. This design consists of four relays: two instantaneous acting and two time delay. The time relays are one second operate - one second release relays. The concept of this design is to reduce spurious operation both on voltage loss and voltage restoration. An undervoltage condition will result in isolating the Class 1E buses from all offsite sources, initiating emergency diesel generator start and load shedding on the Class 1E buses, and lastly, permitting closure of the emergency diesel generator supply breakers. Figures 1 and 2 indicate the existing design.

The existing system does not bypass the load-shedding feature once the emergency diesels are energizing the Class 1E buses.

3.2 MODIFICATIONS

The licensee has proposed a design change which includes automatic degraded voltage protection. This modification consists of the addition of two time-delayed, undervoltage relays on each 4160-volt Class 1E bus. Also, the licensee will make circuit design changes to prevent load shedding when the Class 1E buses are being powered by the diesel generators, and will reinstate this load-shedding feature if the diesel generator breaker trips. The limiting conditions for operation and surveillance requirements for the proposed design changes as presented in this evaluation are documented in the licensees's proposed Technical Specifications.



Note: Only bus 15 logic is shown.

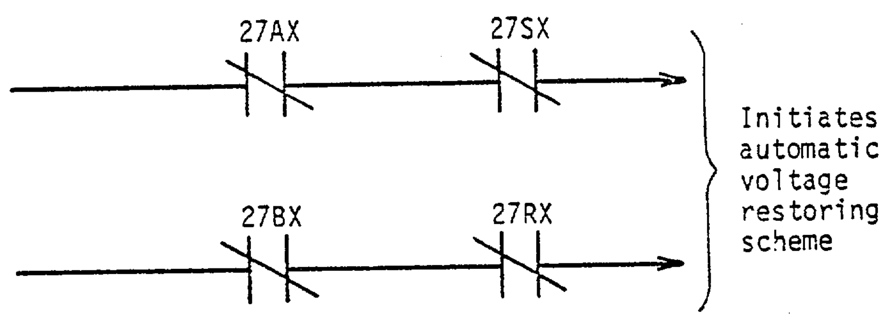
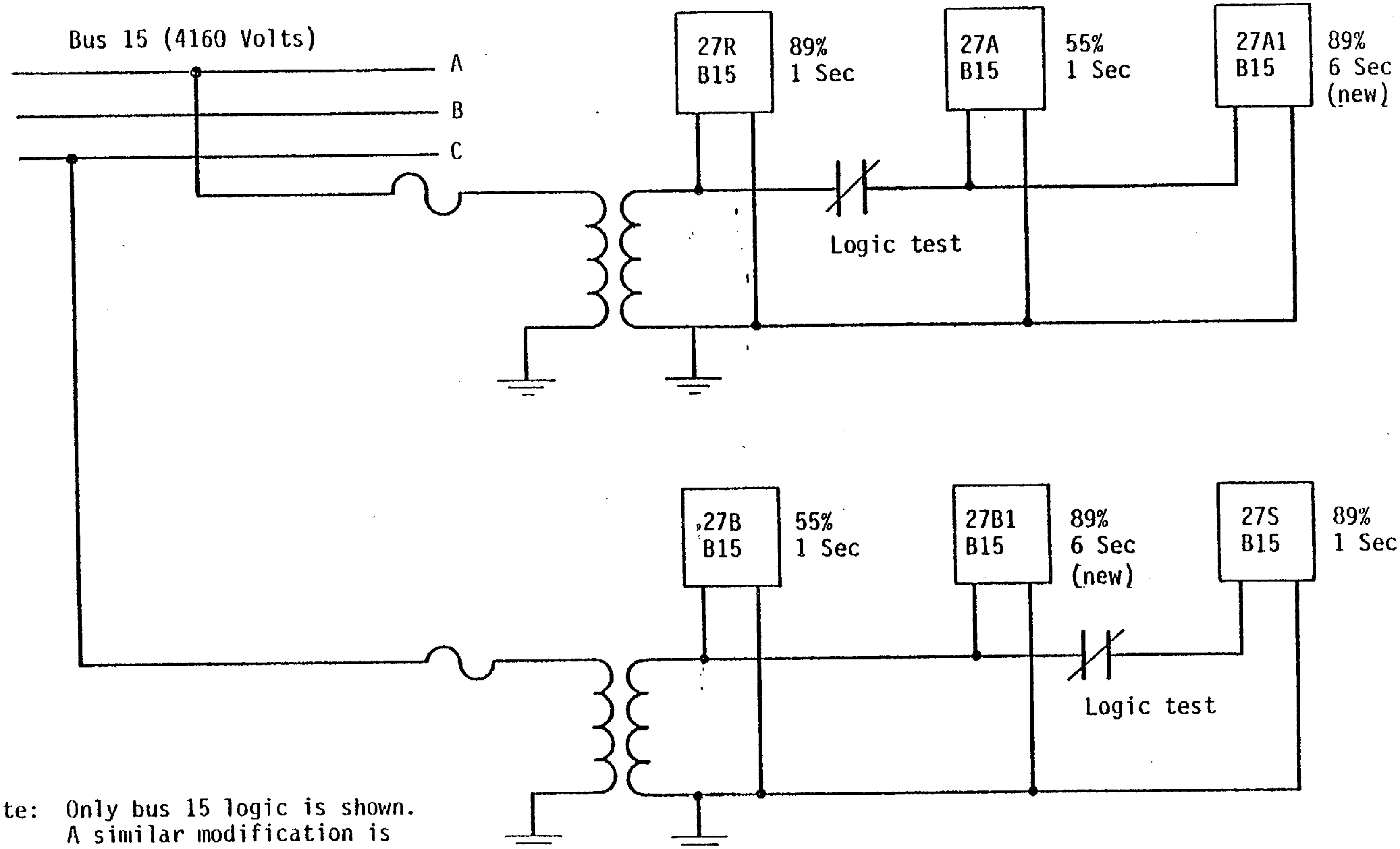


Figure 2. Existing loss of voltage logic at Prairie Island Nuclear Generating Plant.



Note: Only bus 15 logic is shown. A similar modification is required on buses 16, 25, and 26.

Figure 3. Modified bus 15 potential transformer circuit for Prairie Island Nuclear Generating Plant.

voltage restoring scheme. The time for this relay dropout is inversely related to voltage taking 1 second at the 55 percent (±5 percent) voltage level down to nearly instantaneous operation at zero volts. This same logic will be used on all four of the Class 1E emergency buses.

(3) "The time delay selected shall be based on the following conditions."

(a) "The allowable time delay, including margin, shall not exceed the maximum time delay that is assumed in the FSAR accident analysis."

The proposed time delay of 6 seconds (±2 seconds) does not exceed this maximum time delay. This is based on the ECCS analysis assuming a 25-second time delay in safety injection system delivery. Upon initiation of the voltage restoration scheme by a degraded voltage condition, 7 seconds are required for diesel startup and voltage restoration. Following this action, 4 seconds are required to trip the source breakers. At this time the generator output breakers close and the safety injection pumps are powered. Ten seconds are then required for the motor-operated valves to completely actuate to their emergency positions. Total time is 21 seconds.

(b) "The time delay shall minimize the effect of short-duration disturbances from reducing the unavailability of the offsite power sources."

The licensee's proposed time delay of 6 seconds (±2 seconds) is long enough to override any short grid disturbances. This will be confirmed by testing once the circuitry is installed.

(c) "The allowable time duration of a degraded voltage condition at all distribution system levels shall not result in failure of safety systems or components."

A review of the licensee's voltage analysis indicates that the time delay will not cause any failure of any equipment connected to and associated with the Class 1E emergency power system.

(4) "The undervoltage monitors shall automatically initiate the disconnection of offsite power sources whenever the voltage setpoint and time delay limits have been exceeded."

3.3.3 Position 3: Onsite Power Source Testing

The third position requires that certain test requirements be included in the Technical Specifications. These tests are to "... demonstrate the full functional operability and independence of the onsite power sources at least once per 18 months during shutdown." The tests are to simulate loss of offsite power in conjunction with a safety injection actuation signal and to simulate interruption and subsequent reconnection of onsite power sources. These tests will verify the proper operation of the load-shed system, the load-shed bypass when the emergency diesel generators are supplying their respective buses, and that there is no adverse interaction between the onsite and offsite power sources.

The licensee will verify the requirements of the NRC by testing the system by initiating loss of offsite power in conjunction with a simulated safety injection signal. The test sequence will be bus de-energization, load shedding, voltage restoration, and load sequencing. The operating time on emergency onsite power will be at least five minutes. The licensee affirms that interruption of the diesel generators to test load shedding and load sequencing is not necessary, as this logic is tested during the simulated loss of offsite power in conjunction with a safety injection actuation signal.

3.4 TECHNICAL SPECIFICATIONS

The changes proposed by Northern States Power Company to the Prairie Island Nuclear Generating Plant Technical Specifications reflect the proposed design modifications. Specifically, the proposed changes are as follows:

(1) Include the trip setpoints for the degraded voltage protection sensors and the associated time delays with tolerances (89 percent [$\pm$1 percent] and 6 seconds [$\pm$2 seconds]).

4. CONCLUSIONS

Based on the information provided by Northern States Power Company, it has been determined that the proposed modifications comply with Position 1. All of the staff's requirements and design base criteria have been met. The voltage setting and the time delays will protect the Class 1E equipment from a sustained degraded voltage condition of the offsite power source.

The modifications to the logic of the load-shed circuitry comply with Position 2, and will prevent adverse interaction of the offsite and onsite emergency power systems.

The proposed additions to the Technical Specifications and the method of testing the logic circuitry have been reviewed and found to meet the intent of Position 3.

Accordingly, we recommend that the NRC approve the proposed design modifications and Technical Specifications.

REFERENCES

1. NRC letter to Northern States Power Co. letter (L. O. Mayer), dated June 3, 1977.

2. Northern States Power Co. letter (L. O. Mayer) to NRC, dated May 4, 1978.

3. Northern States Power Co. letter (L. O. Mayer) to NRC, dated October 12, 1979.

4. Code of Federal Regulations, Title 10, Part 50 (10 CFR 50), General Design Criterion 17 (GDC 17), "Electric Power Systems" of Appendix A, "General Design Criteria for Nuclear Power Plants."

5. IEEE Std. 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations."

6. IEEE Std. 308-1974, "Criteria for Class 1E Power Systems for Nuclear Power Generating Stations."

LLL:1980/4

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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 these amendments was not required since the amendments do not involve a significant hazards consideration.

The Commission has determined that the issuance of these amendments will not result in any significant environmental impact and that pursuant to 10 CFR §51.5(d)(4) an environmental impact statement or negative declaration and environmental impact appraisal need not be prepared in connection with issuance of these amendments.

For further details with respect to this action, see (1) the application for amendments dated February 20, 1980, May 16, 1980 and July 31, 1980, (2) Amendment Nos. 49 and 43 to License Nos. DPR-42 and DPR-60, and (3) the Commission's related Safety Evaluation. All of 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 Environmental Conservation Library, 300 Nicollet Mall, Minneapolis, Minnesota 55401. 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 28th day of July, 1981.

FOR THE NUCLEAR REGULATORY COMMISSION

R. A. Clark

R. A. Clark, Chief
Operating Reactors Branch #3
Division of Licensing