EXHIBIT B

License Amendment Request Dated September 24, 1982

Exhibit B, attached, consists of the following revised pages for the Appendix A Technical Specifications which incorporate the proposed changes.

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4. Protective Function - A system protective action which results from the protective action of the channels monitoring a particular plant condition.

R. Rated Neutron Flux - Rated flux is the neutron flux that corresponds to a steady-state power level of 1670 thermal megawatts.

S. Rated Thermal Power - Rated thermal power means a steady-state power level of 1670 thermal megawatts.

T. Reactor Coolant System Pressure or Reactor Vessel Pressure - Unless otherwise indicated, reactor vessel pressures listed in the Technical Specifications are those existing in the vessel steam space.

U. Refueling Operation and Refueling Outage - Refueling Operation is any operation when the reactor water temperature is less than 212°F and movement of fuel or core components is in progress. For the purpose of designating frequency of testing and surveillance, a refueling outage shall mean a regularly scheduled refueling outage; however, where such outages occur within 8 months of the completion of the previous refueling outage, the required surveillance testing need not be performed until the next regularly scheduled outage.

V. Safety Limit - The safety limits are limits below which the maintenance of the cladding and primary system integrity are assured. Exceeding such a limit is cause for plant shutdown and review by the Commission before resumption of plant operation. Operation beyond such a limit may not in itself result in serious consequences but it indicates an operational deficiency subject to regulatory review.

W. Secondary Containment Integrity - Secondary Containment Integrity means that the reactor building is closed and the following conditions are met:

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

2. The standby gas treatment system is operable.

3. All reactor building ventilation system automatic isolation valves are operable or are secured in the closed position.

X. Sensor Check - A qualitative determination of operability by observation of sensor behavior during operation. This determination shall include, where possible, comparison with other independent sensors measuring the same variable.

4.0 SURVEILLANCE REQUIREMENTS

A. The surveillance requirements of this section shall be met. Each surveillance requirement shall be performed at the specified times except as allowed in B and C below.

B. Specific time intervals between tests may be adjusted plus or minus 25% to accomodate normal test schedules with the exception that, the intervals between tests scheduled for refueling shutdowns shall not exceed two years.

C. Whenever the plant condition is such that a system or component is not required to be operable the surveillance testing associated with that system or component may be discontinued. Discontinued surveillance tests shall be resumed less than one test interval before establishing plant conditions requiring operability of the associated system or component, unless such testing is not practicable (e. g. APRM and IRM heat balance calibration cannot be done prior to reaching power operation) in which case the testing will be resumed within 48 hours of attaining the plant condition which permits testing to be accomplished.

3.0 LIMITING CONDITIONS FOR OPERATION	4.0 SURVEILLANCE REQUIREMENTS

3.0 LIMITING CONDITIONS FOR OPERATION

B. Upon discovery that the requirements for the number of operable or operating trip systems or instrument channels are not satisfied, action shall be initiated to:

1. Satisfy the minimum requirements by placing appropriate devices, channels, or trip systems in the tripped condition, or

2. Place and maintain the plant under the specified required conditions using normal operating procedures

C. RPS Power Monitoring System

1. Except as specified below, both channels of the power monitoring system for the MG set or alternate source supplying each reactor protection system bus shall be operable with the following setpoints:

   a. Over-voltage - $\leq$128 VAC
   b. Under-voltage - $\geq$104 VAC
   c. Under-frequency - $\geq$57 HZ

2. With one RPS electric power monitoring channels for the MG set or alternate source supplying each reactor protection system bus inoperable, restore the inoperable channel to Operable status within 72 hours or remove the associated RPS MG set or alternate power supply from service.

3. With both RPS electric power monitoring channels for the MG set or alternate source supplying each reactor protection system bus inoperable, restore at least one to Operable status within 30 minutes or remove the associated RPS MG set or alternate power supply from service.

4.0 SURVEILLANCE REQUIREMENTS

B. Once per day during power operation the MFLPD (Maximum Fraction of Limiting Power Density) shall be checked and the scram setting given by the equation in Specification 2.3.A shall be adjusted if necessary.

C. RPS Power Monitoring System

1. Instrument Functional Tests of each RPS power monitoring channel shall be performed at least once every six months.

2. At least once each Operating Cycle an Instrument Calibration of each RPS power monitoring channel shall be performed to verify over-voltage, under-voltage, and under-frequency setpoints.

3.0 LIMITING CONDITIONS FOR OPERATION

E. Reactor Building Ventilation Isolation and Standby Gas Treatment System Initiation

1. a. Except as specified in 3.2.E.1.b below, four radiation monitors shall be operable at all times.

   b. One of the two monitors in the ventilation plenum and one of the two radiation monitors on the refueling floor may be inoperable for 24 hours. If the inoperable monitors are not restored to service in this time, the reactor building ventilation system shall be isolated and the standby gas treatment system operated until repairs are complete.

2. The radiation monitors shall be set to trip as follows:

   (a) ventilation plenum $\leq$ 3 mr/hr
   (b) refueling floor $\leq$100 mr/hr

3. When irradiated fuel is in the reactor vessel and the reactor water temperature is above 212°F, the limiting conditions for operation for the instrumentation listed in Table 3.2.4 shall be met.

F. Recirculation Pump Trip and Alternate Rod Injection Initiation

1. Whenever the reactor is in the RUN Mode, the limiting conditions for operation for the instrumentation listed in Table 3.2.5 shall be met.

4.0 SURVEILLANCE REQUIREMENTS

TABLE 3.2.1 - Continued

Function	Trip Settings	Total No. of Instrument Channels Per Trip System	Min. No. of Operable or Operating Instrument Channels Per Trip System (1,2)	Required Conditions
b. High Drywell Pressure (5)	≤ 2 psig	2	2	D
3. Reactor Cleanup System (Group 3)				
a. Low Reactor Water Level	≥ 10'6" above the top of the active fuel	2	2	E
b. High Drywell Pressure	≤ 2 psig	2	2	E
4. HPCI Steam Lines				
a. HPCI High Steam Flow	≤150,000 lb/hr with ≤60 second time delay	2(4)	2	F
b. HPCI High Steam Flow	≤300,000 lb/hr	2(4)	2	F
c. HPCI Steam Line Area High Temp.	≤200°F	16(4)	16	F
5. RCIC Steam Lines				
a. RCIC High Steam Flow	≤45,000 lb/hr	2(4)	2	G
b. RCIC Steam Line Area	≤200°F	16(4)	16	G
6. Shutdown Cooling Supply Isolation				
a. Reactor Pressure Interlock	≤75 psig at pump suction	2(4)	2	C

Table 3.2.5

Instrumentation that Initiates a Recirculation Pump Trip and Alternate Rod Injection

Function	Trip Setting	Minimum No. of Operable or Operating Trip Systems (1)	Total No. of Instrument Channels Per Trip System	Minimum No. of Operable or Operating Instrument Channels Per Trip System (1)	Required Conditions*
1. High Reactor Dome Pressure	≤ 1150 psig	2	2	2	A
2. Low Reactor Water Level	≥6' 6" above the top of the active fuel.	2	2	2	A

NOTE:

1. Upon discovery that minimum requirements for the number of operable or operating trip systems or instrument channels are not satisfied, action shall be initiated to:

   a. Satisfy the requirements by placing the appropriate channels or systems in the tripped condition, or

   b. Place the plant under the specified required condition using normal operating procedures.

* Required conditions when minimum conditions for operation are not satisfied:

   A. Reactor in Startup, Refuel or Shutdown mode.

Table 4.2.1 - Continued
Minimum Test and Calibration Frequency For Core Cooling
Rod Block and Isolation Instrumentation

Instrument Channel	Test (3)	Calibration (3)	Sensor Check (3)
3. Steam Line Low Pressure	Note 1	Once/3 months	None
4. Steam Line High Radiation	Once/week (5)	Note 6	Once/shift
<u>HPCI ISOLATION</u>			
1. Steam Line High Flow	Once/month	Once/3 months	None
2. Steam Line High Temperature	Once/month	Once/3 months	None
<u>RCIC ISOLATION</u>			
1. Steam Line High Flow	Once/month	Once/3 months	None
2. Steam Line High Temperature	Note 1	Once/3 months	None
<u>REACTOR BUILDING VENTIALTION</u>			
1. Radiation Monitors (Plenum)	Note 1	Once/3 months	Once/shift
2. Radiation Monitors (Refueling Floor)	Note 1	Once/3 months	(4)
<u>OFF-GAS ISOLATION</u>			
1. Radiation Montiors (Air Ejectors)	Notes (1,5)	Note 6	Once/shift
<u>RECIRCULATION PUMP TRIP</u>			
1. Reactor High Pressure	Note 1	Once/Operating Cycle-Transmitter Once/3 Months-Trip Unit	Once/Day
2. Reactor Low Water Level (Note 7)	Once/month	Once/Operating Cycle-Transmitter Once/3 Months-Trip Unit	Once/shift
<u>SHUTDOWN COOLING SUPPLY ISOLATION</u>			
1. Reactor Pressure Interlock	Note 1	Once/3 months	None

Bases Continued:

increases core voiding, a negative reactivity feedback. High pressure sensors initiate the pump trip in the event of an isolation transient. Low level sensors initiate the trip on loss of feedwater (and the resulting MSIV closure). The recirculation pump trip is only required at high reactor power levels, where the safety/relief valves have insufficient capacity to relieve the steam which continues to be generated after reactor isolation in this unlikely postulated event, requiring the trip to be operable only when in the RUN mode is therefore conservative.

The ATWS high reactor pressure and low water level logic also initiates the Alternate Rod Injection system. Two solenoid valves are installed in the scram air header upstream of the hydraulic control units. Each of the two trip systems energizes a valve to vent the header and causes rod insertion. This greatly reduces the long term consequences of an ATWS event.

Although the operator will set the set points within the trip settings specified in Tables 3.2.1, 3.2.2, 3.2.3, 3.2.4, 3.2.5, and 3.2.6, the actual values of the various set points can differ appreciably from the value the operator is attempting to set. The deviations could be caused by inherent instrument error, operator setting error, drift of the set point, ect. Therefore, these deviations have been accounted for in the various transient analyses and the actual trip settings may vary by the following amounts.

Table 3.2.7
Trip Functions And Deviations

	Trip Function	Deviation
Reactor Building Ventilation Isolation and Standby Gas Treatment System Initiation Specification 3.2.E.3 and Table 3.2.4	Ventilation Plenum Radiation Monitors	+0.2 Mr/Hr
	Refueling Floor Radiation Monitors	+5 Mr/Hr
	Low Reactor Water Level	-6 inches
	High Drywell Pressure	+ 1 psi
Primary Containment Isolation Functions Table 3.2.1	Low Low Water Level	-3 inches
	High Flow in Main Steam Line	+2 %
	High Temp. in Main Steam Line Tunnel	+10°F
	Low Pressure in Main Steam Line	-10 psi
	High Drywell Pressure	+1 psi
	Low Reactor Water Level	-6 inches
	HPCI High Steam Flow	+7,500 lb/hr
	HPCI Steam Line Area High Temp.	+2°F
	RCIC High Steam Flow	+2250 lb/hr
	RCIC Steam Line Area High Temp	+2°F
	Shutdown Cooling Supply Iso	+25 psi

Table 3.2.7 - Continued
Trip Function and Deviations

	Trip Function	Deviation
Instrumentation That Initiates Emergency Core Cooling Systems Table 3.2.2	Low-Low Reactor Water Level	-3 Inches
	Reactor Low Pressure (Pump Start) Permissive	-10 psi
	High Drywell Pressure	+1 psi
	Low Reactor Pressure (Valve Permissive)	-10 psi
Instrumentation That Initiates Rod Block Table 3.2.3	IRM Downscale	-2/125 of Scale
	IRM Upscale	+2/125 of Scale
	APRM Downscale	-2/125 of Scale
	APRM Upscale	See Basis 2.3
	RBM Downscale	-2/125 of Scale
	RBM Upscale	Same as APRM Upscale
	Scram Discharge Volume-High Level	+ 1 gallon
Instrumentation That Initiates Recirculation Pump Trip and Alternate Rod Injection	High Reactor Pressure	+ 12 psi
	Low Reactor Water Level	-3 Inches

A violation of this specification is assumed to occur only when a device is knowingly set outside of the limiting trip settings, or, when a sufficient number of devices have been affected by any means such that the automatic function is incapable of operating within the allowable deviation while in a reactor mode in which the specified function must be operable or when actions specified are not initiated as specified.

The analysis assumes 50 milliseconds for Reactor Protection System delay, 200 milli seconds from de-energization of scram solenoids to the beginning of rod motion, and 175 milliseconds later the rods are at the 5% position.

Section 3.3.C.3 allows a lower MCPR limit to be used if the cycle average scram time (τ_{AVE}) is less than the adjusted analysis mean scram time (τ_B) (see Reference 7, of Section 3.11)

τ_{AVE} is the weighted cycle average scram time to the 20% insertion position (~notch 38) of all the operable rods measured at any point in the cycle.

$$\tau_{AVE} = \frac{\sum_{i=1}^{n} N_i \tau_i}{\sum_{i=1}^{n} N_i}$$

where: n = the number of surveillance tests performed to date in this cycle.

N_i = number of control rods measured in the ith test.

τ_i = average scram time to the 20% insertion position of all rods measured in the ith test.

τ_B is the adjusted analysis mean scram time to the 20% insertion position.

$$\tau_B = 0.710 + 0.0875 \left(\frac{N_1}{\sum_{i=1}^{n} N_i} \right)^{\frac{1}{2}}$$

where: N_1 = total number of active rods measured in the first test following core alterations.

0.710 = the mean scram time used in the analysis.

0.0875 = 1.65x0.053 where 1.65 is the appropriate statistical number to provide a 95% confidence level and, 0.053 is the standard deviation of the distribution for average scram insertion time to the 20% position, that was used in the analysis.

3.0 LIMITING CONDITIONS FOR OPERATION	4.0 SURVEILLANCE REQUIREMENTS

F. (Deleted)

G. Jet Pumps

Whenever the reactor is in the Startup or Run modes, all jet pumps shall be operable with the requirement that each individual jet pump diffuser to lower plenum differential pressure (D/P) percent deviation from average loop D/P shall not differ by more than 20% deviation from its normal range of deviation. With one or more jet pumps exceeding the stated criteria, evaluate the reason for the deviation, and in the circumstance that one or more of the jet pumps are determined to be inoperable, the reactor shall be placed in a cold shutdown condition within 24 hours.

F. (Deleted)

G. Jet Pumps

Whenever there is recirculation flow with the reactor in the Startup or Run mode, operating jet pumps shall be demonstrated Operable daily and following any unexplained change in core flow, jet pump loop flow, recirculation loop flow, or core plate differential pressure, by recording jet pump loop flows, recirculation pump flows, recirculation pump speeds, and individual jet pump D/P, and verifying that:

1. The recirculation pump flow/speed ratio deviation from normal expected operating range does not exceed 5%.

2. The jet pump loop flow/speed ratio deviation from normal expected operating range does not exceed 5%.

If either of these conditions are not met, determine individual jet pump D/P percent deviation from average loop D/P and compare to the Limiting Conditions for Operation. It may be necessary to increase pump speed to above 60% to conclude whether a jet pump is inoperable.

H. Snubbers

1. Except as permitted below, all snubbers listed in Table 3.6.1 shall be operable above Cold Shutdown. Snubbers may be inoperable in Cold Shutdown and Refueling Shutdown whenever the supported system is not required to be Operable.

2. With one or more snubbers made or found to be inoperable for any reason when Operability is required, within 72 hours:

   a. Replace or restore the inoperable snubbers to Operable status and perform an engineering evaluation or inspection of the supported components, or

   b. Determine through engineering evaluation that the as-found condition of the snubber had no adverse effect on the supported components and that they would retain their structural integrity in the event of the design basis seismic event, or

   c. Declare the supported system inoperable and take the action required by the Technical Specifications for inoperability of that system.

H. Snubbers

The following surveillance requirements apply to all snubbers listed in Table 3.6.1.

1. Visual inspection of snubbers shall be conducted in accordance with the following schedule:

No. of Snubbers Found Inoperable per Inspection Period	Next Required Inspection Period
0	18 months ± 25%
1	12 months ± 25%
2	6 months ± 25%
3,4	124 days ± 25%
5,6,7	62 days ± 25%
8 or more	31 days ± 25%

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

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

3. Functional testing of snubbers shall be conducted at least once per Operating Cycle during cold shutdown. Ten percent of the total number of each brand of snubber shall be functionally tested either in place or in a bench test. For each snubber that does not meet the functional test acceptance criteria in Specification 4.6.H.4 below, an additional ten percent of that brand shall be functionally tested until no more failures are found or all snubbers of that brand have been tested.

The representative sample selected for functional testing shall include the various configurations, operating environments, and the range of size and capacity of the snubbers.

In addition to the regular sample and specified re-samples, snubbers which failed the previous functional test shall be retested during the next test period if they were reinstalled as a safety-related snubber. If a spare snubber has been installed in place of a failed safety related snubber, it shall be tested during the next period.

If any snubber selected for functional testing either fails to lockup or fails to move (i.e. frozen in place) the cause shall be evaluated and if caused by manufacturer or design deficiency, all snubbers of the same design subject to the same defect shall be functionally tested.

TABLE 3.6.1
SAFETY RELATED HYDRAULIC SNUBBERS

SNUBBER NO.	SYSTEM	LOCATION	ELEVATION	AZIMUTH (AIRLOCK 0 REF)	ACCESSIBLE -A INACCESSIBLE-I
PS1-H2	MAIN STEAM	DRYWELL	953	071	I
PS1-H3	MAIN STEAM	DRYWELL	950	148	I
PS2-H2	MAIN STEAM	DRYWELL	950	120	I
PS3-H2	MAIN STEAM	DRYWELL	950	240	I
PS4-H3	MAIN STEAM	DRYWELL	950	212	I
RV24-H3	SAFETY-RELIEF	DRYWELL	950	110	I
RV24-H4	SAFETY-RELIEF	DRYWELL	935	100	I
RV24-H4A	SAFETY-RELIEF	DRYWELL	935	100	I
RV24-H5	SAFETY-RELIEF	DRYWELL	935	110	I
RV24-NS2	SAFETY-RELIEF	DRYWELL	934	081	I
RV24-NS3	SAFETY-RELIEF	DRYWELL	962	090	I
RV24-N1	SAFETY-RELIEF	DRYWELL	953	090	I
RV24A-H4A	SAFETY-RELIEF	DRYWELL	947	048	I
RV24A-H7	SAFETY-RELIEF	DRYWELL	953	088	I
RV24A-H8	SAFETY-RELIEF	DRYWELL	939	032	I
RV24A-NS1	SAFETY-RELIEF	DRYWELL	952	050	I
RV24A-NS2	SAFETY-RELIEF	DRYWELL	952	055	I
RV24A-N1	SAFETY-RELIEF	DRYWELL	956	086	I
RV25-H1	SAFETY-RELIEF	DRYWELL	953	180	I
RV25-H1A	SAFETY-RELIEF	DRYWELL	953	180	I
RV25-H2	SAFETY-RELIEF	DRYWELL	948	190	I
RV25-H2A	SAFETY-RELIEF	DRYWELL	948	190	I
RV25-H3	SAFETY-RELIEF	DRYWELL	934	180	I
RV25-NS1	SAFETY-RELIEF	DRYWELL	952	160	I
RV25-NS2	SAFETY-RELIEF	DRYWELL	952	195	I
RV25-NS3	SAFETY-RELIEF	DRYWELL	921	158	I
RV25A-H2	SAFETY-RELIEF	DRYWELL	945	120	I
RV25A-H2A	SAFETY-RELIEF	DRYWELL	945	120	I
RV25A-H7	SAFETY-RELIEF	DRYWELL	953	135	I
RV25A-NS1	SAFETY-RELIEF	DRYWELL	934	110	I
RV25A-NS2	SAFETY-RELIEF	DRYWELL	934	102	I
RV25A-NS3	SAFETY-RELIEF	DRYWELL	952	122	I
RV26-H1	SAFETY-RELIEF	DRYWELL	953	200	I
RV26-H1A	SAFETY-RELIEF	DRYWELL	953	200	I
RV26-H2	SAFETY-RELIEF	DRYWELL	947	200	I
RV26-H2A	SAFETY-RELIEF	DRYWELL	947	200	I
RV26-N1	SAFETY-RELIEF	DRYWELL	956	200	I
RV26A-H2	SAFETY-RELIEF	DRYWELL	940	250	I
RV26A-H2A	SAFETY-RELIEF	DRYWELL	935	250	I
RV26A-NS1	SAFETY-RELIEF	DRYWELL	934	240	I
RV26A-NS2	SAFETY-RELIEF	DRYWELL	934	230	I
RV26A-NS3	SAFETY-RELIEF	DRYWELL	920	257	I
RV26A-N1	SAFETY-RELIEF	DRYWELL	950	250	I
RV26A-N2	SAFETY-RELIEF	DRYWELL	951	250	I
RV27-H1	SAFETY-RELIEF	DRYWELL	950	320	I
RV27-H1A	SAFETY-RELIEF	DRYWELL	950	230	I
RV27-H5	SAFETY-RELIEF	DRYWELL	945	270	I

TABLE 3.6.1
SAFETY RELATED HYDRAULIC SNUBBERS

SNUBBER NO.	SYSTEM	LOCATION	ELEVATION	AZIMUTH (AIRLOCK 0 REF)	ACCESSIBLE -A INACCESSIBLE-I
RV27-H6	SAFETY-RELIEF	DRYWELL	945	270	I
RV27-NS1	SAFETY-RELIEF	DRYWELL	934	250	I
RV27-NS2	SAFETY-RELIEF	DRYWELL	934	280	I
RV27-N1	SAFETY-RELIEF	DRYWELL	956	270	I
RV27A-H2A	SAFETY-RELIEF	DRYWELL	953	290	I
RV27A-H3	SAFETY-RELIEF	DRYWELL	953	290	I
RV27A-H9	SAFETY-RELIEF	DRYWELL	938	290	I
RV27A-NS1	SAFETY-RELIEF	DRYWELL	952	282	I
RV27A-NS2	SAFETY-RELIEF	DRYWELL	952	279	I
RV27A-NS3	SAFETY-RELIEF	DRYWELL	952	282	I
RV27A-N1	SAFETY-RELIEF	DRYWELL	956	270	I
R26-NS1	SAFETY-RELIEF	DRYWELL	952	200	I
SS-1	MAIN STEAM	DRYWELL	953	279	I
SS-1AR	RECIRCULATION	DRYWELL	922	315	I
SS-1BR	RECIRCULATION	DRYWELL	922	135	I
SS-11	FEEDWATER	DRYWELL	952	302	I
SS-12	FEEDWATER	DRYWELL	952	058	I
SS-13	FEEDWATER	DRYWELL	952	258	I
SS-14	FEEDWATER	DRYWELL	952	096	I
SS-17A	RHR	DRYWELL	964	072	I
SS-17B	RHR	DRYWELL	964	072	I
SS-18A	RHR	DRYWELL	964	288	I
SS-18B	RHR	DRYWELL	964	288	I
SS-19	RHR	DRYWELL	964	341	I
SS-2	MAIN STEAM	DRYWELL	953	081	I
SS-2AR	RECIRCULATION	DRYWELL	927	302	I
SS-2BR	RECIRCULATION	DRYWELL	927	122	I
SS-20	RHR	DRYWELL	964	019	I
SS-3	MAIN STEAM	DRYWELL	950	212	I
SS-3AR	RECIRCULATION	DRYWELL	927	328	I
SS-3BR	RECIRCULATION	DRYWELL	927	148	I
SS-4	MAIN STEAM	DRYWELL	950	148	I
SS-4AR(A)	RECIRCULATION	DRYWELL	934	302	I
SS-4AR(B)	RECIRCULATION	DRYWELL	934	323	I
SS-4BR(A)	RECIRCULATION	DRYWELL	934	120	I
SS-4BR(B)	RECIRCULATION	DRYWELL	934	149	I
SS-40	HPCI	MAIN STEAM CHASE			I
SS-5AR	RECIRCULATION	DRYWELL	941	315	I
SS-5BR	RECIRCULATION	DRYWELL	941	135	I
SS-6AR	RECIRCULATION	DRYWELL	953	261	I
SS-6BR	RECIRCULATION	DRYWELL	953	099	I
SS-7	MAIN STEAM	DRYWELL	953	240	I
SS-7AR	RECIRCULATION	DRYWELL	953	323	I
SS-7BR	RECIRCULATION	DRYWELL	953	032	I
SS-8	MAIN STEAM	DRYWELL	953	120	I
SS-8AR	RECIRCULATION	DRYWELL	927	270	I
SS-8BR	RECIRCULATION	DRYWELL	927	090	I

TABLE 3.6.1
SAFETY RELATED HYDRAULIC SNUBBERS

SNUBBER NO.	SYSTEM	LOCATION	ELEVATION	AZIMUTH (AIRLOCK 0 REF)	ACCESSIBLE -A INACCESSIBLE-I
SS-21	RHR	TORUS FL LV - S WALL			A
SS-22	RHR	TORUS FL LV - S WALL			A
SS-23	RHR	B RHR ROOM FL LV			A
SS-24	RHR	A RHR ROOM FL LV			A
SS-25	RHR	TORUS CATWK-SE WALL			A
SS-26	CORE SPRAY	B RHR ROOM FL LVL			A
SS-27	CORE SPRAY	B RHR ROOM FL LVL			A
SS-28A	CORE SPRAY	A RHR ROOM FL LVL			A
SS-28B	CORE SPRAY	A RHR ROOM FL LVL			A
SS-29	RHR	OVER N2 ANALYZER	954		A
SS-30	RHR	OVER N2 ANALYZER	954		A
SS-31	RHR	TORUS CATWK			A
SS-32A	RHR	A RHR ROOM - BY HX	916		A
SS-32B	RHR	A RHR ROOM - BY HX	916		A
SS-33	RHR	ABOVE TORUS			A
SS-34	RHR	ABOVE TORUS			A
SS-35	HPCI	HPCI ROOM - N WALL	912		A
SS-36A	HPCI	HPCI ROOM - FL LVL			A
SS-36B	HPCI	HPCI ROOM - FL LVL			A
SS-37	HPCI	HPCI ROOM - W WALL	905		A
SS-38A	RCIC	RCIC ROOM - W WALL	906		A
SS-38B	RCIC	RCIC ROOM - W WALL	906		A
SS-41	CORE SPRAY	ABOVE TORUS CATWK	927		A
SS-42	HPCI	ABOVE TORUS RING HDR	906		A

G. Jet Pumps

By monitoring jet pump performance on a prescribed schedule, significant degradation in performance that would precede jet pump failure can be detected. An inoperable jet pump is not, in itself, a sufficient reason to declare a recirculation loop inoperable, but it may present a hazard in the event of a large break accident by reducing the capability of reflooding the core; thus, the requirement for shutdown of the reactor with an inoperable jet pump.

The jet pump performance monitoring procedures are comprised of the following tests:

1. Core Flow versus Square Root of Core Plate Differential Pressure: change in core resistance is the main contributor to recirculation system performance changes. If core resistance increases, it requires more energy (pump speed) to produce rated core flow. If resistance decreases, less speed is needed.

2. Recirculation Pump Flow/Speed Ratio: the pump operating characteristic is determined by the flow resistance from the loop suction through the jet pump nozzle. Since this resistance is essentially independent of core power, the flow is linearly proportional to pump speed, making their ratio a constant (flow/RPM is constant). A decrease in the ratio indicates a plug, flow restriction, or loss in pump hydraulic performance. An increase indicates a leak or new flow path between the recirculation pump discharge and jet pump nozzle.

3. Jet Pump Loop Flow/Recirculation Pump Speed Ratio: this relationsbip is an indication of overall system performance.

4. Jet Pump Differential Pressure Relationships: if a potential problem is indicated, the individual jet pump differential pressures are used to determine if a problem exists since this is the most sensitive indicator of significant jet pump performance degradation.

4. Pressure Suppression Chamber-Drywell Vacuum Breakers

   a. When primary containment is required, all drywell-suppression chamber vacuum breakers shall be operable and positioned in the closed position as indicated by the position indication system, except during testing and except as specified in 3.7.A.4.b through 3.7.A.4.d below.

   b. Any drywell-suppression chamber vacuum breaker may be nonfully closed as indicated by the position indication and alarm systems provided that drywell to suppression chamber differential pressure decay does not exceed that shown on Figure 3.7.1.

   c. Up to two drywell-suppression chamber vacuum breakers may be inoperable provided that: (1) the vacuum breakers are determined to be fully closed and at least one position alarm circuit is operable or (2) the vacuum breaker is secured in the closed position.

   d. Drywell-suppression chamber vacuum breakers may be cycled, one at a time using the exercise test push-button, during containment inerting and deinerting operations to assist in purging air or nitrogen from the suppression chamber vent header.

4. Pressure Suppression Chamber-Drywell Vacuum Breakers

   a. Operability and full closure of the drywell-suppression chamber vacuum breakers shall be verified by performance of the following:

      (1) Monthly each operable drywell-suppression chamber vacuum breaker shall be exercised through an opening-closing cycle.

      (2) Once each operating fuel cycle, drywell to suppression chamber leakage shall be demonstrated to be less than that equivalent to a one-inch diameter orifice and each vacuum breaker shall be visually inspected. (Containment access required)

      (3) Once each operating cycle, vacuum breaker position indication and alarm systems shall be calibrated and functionally tested. (Containment access required)

      (4) Once each operating cycle, the vacuum breakers shall be tested to determine that the force required to open each valve from fully closed to fully open does not exceed that equivalent to 0.5 psi acting on the suppression chamber face of the valve disc. (Containment access required)

d. One position alarm circuit can be inoperable providing that the redundant position alarm circuit is operable. Both position alarm circuits may be inoperable for a period not to exceed seven days provided that all vacuum breakers are operable.

b. When the position of any drywell-suppression chamber vacuum breaker valve is indicated to be not fully closed at a time when such closure is required, the drywell to suppression chamber differential pressure decay shall be demonstrated to be less than that shown on Figure 3.7.1 immediately and following any evidence of subsequent operation of the inoperable valve until the inoperable valve is restored to a normal condition.

c. When both position alarm circuits are made or found to be inoperable, the control panel indicator light status shall be recorded daily to detect changes in the vacuum breaker position.

5. Containment Atmosphere Control

a. The primary containment atmosphere shall be reduced to less than 5% oxygen with nitrogen gas whenever the reactor is in the run mode, except as specified in 3.7.A.5.b.

b. Within the 24-hour period subsequent to placing the reactor in the run mode following shutdown, the containment atmosphere oxygen concentration shall be reduced to less than 5% by weight, and maintained in this condition. Deinerting may commence 24 hours prior to leaving the run mode for a reactor shutdown.

5. Containment Atmosphere Control

a. Whenever inerting is required, the primary containment oxygen concentration shall be measured and recorded on a weekly basis.

c. Except for inerting and deinerting operations permitted in (b) above, all containment purging and venting above cold shutdown shall be via a 2-inch purge and vent valve bypass line and the Standby Gas Treatment System. Inerting and deinerting operations may be via the 18-inch purge and vent valves(equipped with 40-degree limit stops) aligned to the Reactor Building plenum and vent.

6. If the specifications of 3.7.A cannot be met, the reactor shall be placed in a cold shutdown condition within 24 hours.

B. Standby Gas Treatment System

1. Two separate and independent standby gas treatment system circuits shall be operable at all times when secondary containment integrity is required, except as specified in sections 3.7.B.1.(a) and (b).

a. After one of the standby gas treatment system circuits is made or found to be inoperable for any reason, reactor operation and fuel handling is permissible only during the succeeding seven days, provided that all active components in the other standby gas treatment system shall be demonstrated to be operable within 2 hours and daily thereafter. Within 36 hours following the 7 days, the reactor shall be placed in a condition for which the standby gas treatment system is not required in accordance with Specification 3.7.C.1.(a) through (d).

B. Standby Gas Treatment System

1. At least once per month, initiate from the control room 3500 cfm (±10%) flow through both circuits of the standby gas treatment system. In addition:

a. Within 2 hours from the time that one standby gas treatment system circuit is made or found to be inoperable for any reason and daily thereafter for the next succeeding seven days, initiate from the control room 3500 cfm (±10%) flow through the operable circuit of the standby gas treatment system.

2. In the event any isolation valve specified in Table 3.7.1 becomes inoperable, reactor operation in the run mode may continue provided at least one valve in each line having an inoperable valve is closed.

3. If Specification 3.7.D.1 and 3.7.D.2 cannot be met, initiate normal orderly shutdown and have reactor in the cold shutdown condition within 24 hours.

c. At least once per quarter - Continued

   (2) With the reactor power less than 75% of rated, trip main steam isolation valves (one at a time) and verify closure time.

d. At least once per week the main steam-line power-operated isolation valves shall be exercised by partial closure and subsequent reopening.

2. Whenever an isolation valve listed in Table 3.7.1 is inoperable, the position of at least one fully closed valve in each line having an inoperable valve shall be recorded daily.

3. The isolation valves listed in Table 3.7.1 shall be demonstrated Operable prior to returning the valve to service after maintenance, repair, or replacement work is performed on the valve or its associated actuator, control, or power circuit by performance of a cycling test and verification of operating time.

4. The valve seals of the drywell and suppression 18-inch purge and vent valves shall be replaced at least once every five years.

TABLE

PRIMARY CONTAINMENT ISOLATION

Isolation Group	Valve Identification	Number of Valves		Maximum Operating Time (Sec)	Normal Position
		Inboard	Outboard		
1	Main Steam Line Isolation	4	4	$3 \le T \le 5$	Open
1	Main Steam Line Drain	1	1	60	Closed
1	Recirculation Loop Sample Line	1	1	60	Open
2	Drywell Floor Drain		2	60	Open
2	Drywell Equipment Drain		2	60	Open
2	Drywell Vent		2	60	Closed
2	Drywell Vent Bypass		1	60	Closed
2	Drywell Purge Inlet		2	60	* Open
2	Drywell and Suppression Chamber Air Makeup		1	60	Closed
2	Suppression Chamber to Drywell N_2 Recirculation		1	60	* Open
2	Suppression Chamber Vent		2	60	Closed
2	Suppression Chamber Vent Bypass		1	60	* Open
2	Shutdown Cooling System	1	1	120	Closed

* Open to maintain drywell-torus differential pressure. This differential pressure will be removed and the valves will be normally closed following completion of the Mark I containment long term program modifications.

Bases Continued:

One-inch opening of any one valve or a 1/8-inch opeing for all eight valves, measured at the bottom of the disc with the top of the disc at the seat. The position indication system is designed to detect closure within 1/8 inch at the bottom of the disc.

At each refueling outage and following any sigificant maintenance on the vacuum breaker valves, positive seating of the vacuum breakers will be verified by leak test. The leak test is conservatively designed to demonstrate that leakage is less than that equivalent to leakage through a one-inch orifice which is about 3% of the maximum allowable. This test is planned to establish a baseline for valve performance at the start of each operating cycle and to ensure that vacuum breakers are maintained as nearly as possible to their design condition. This test is not planned to serve as a limiting condition for operation.

During reactor operation, an exercise test of the vacuum breakers will be conducted monthly. This test will verify that disc travel is unobstructed and will provide verification that the valves are closing fully through the position indication system. If one or more of the vacuum breakers do not seat fully as determined from the indicating system, a leak test will be conducted to verify that leakage is within the maximum allowable. Since the extreme lower limit of switch detection capability is approximately 1/16", the planned test is designed to strike a balance between the detection switch capability to verify closure and the maximum allowable leak rate. A special test was performed to establish the basis for this limiting condition. During the first refueling outage all ten vacuum breakers were shimmed 1/16" open at the bottom of the disc. The bypass area associated with the shimming corresponded to 63% of the maximum allowable.[1] The results of this test are shown in Figure 3.7.1. Two of the original ten vacuum breakers have since been removed.

When a drywell-suppression chamber vacuum breaker valve is exercised through an opening-closing cycle, the position indicating lights at the remote test panels are designed to function as follows:

Full Closed	2 Green - On 2 Red - Off
Intermediate Position	2 Green - Off 2 Red - Off
Full Open	2 Green - Off 2 Red - On

The remote test panel consists of a push button to actuate the air cylinder for testing, two red lights, Bases Continued:

and two green lights for each of the eight valves. There are four independent limit switches on each valve. The two switches controlling the green lights are adjusted to provide an indication of disc opening of less than 1/8" at the bottom of the disc. These switches are also used to activate the valve position alarm circuits. The two switches controlling the red lights are adjusted to provide indication of the disc very near the full open position.

The control room alarm circuits are redundant and fail safe. This assures that no simple failure will defeat alarming to the control room when a valve is open beyond allowable and when power to the switches fails. The alarm is needed to alert the operator that action must be taken to correct a malfunction or to investigate possible changes in valve position status, or both. If the alarm cannot be cleared due to the inability to establish indication of closure of one or more valves, additional testing is required. The alarm system allows the operator to make this evaluation on a timely basis. The frequency of the testing of the alarms is the same as that required for the position indication system.

Operability of a vacuum breaker valve and the four associated indicating light circuits shall be established by cycling the valve. The sequence of the indicating lights will be observed to be that previously described. If both green light circuits are inoperable, the valve shall be considered inoperable and a pressure test is required immediately and upon indication of subsequent operation. If both red light circuits are inoperable, the valve shall be considered inoperable, however, no pressure test is required if positive closure indication is present.

The 5% oxygen concentration minimizes the possibility of hydrogen combustion following a loss of coolant accident. Significant quantities of hydrogen could be generated if the core cooling systems failed to sufficiently cool the core. The occurrence of primary system leakage following a major refueling outage or other scheduled shutdown is more probable than the occurrence of the loss of coolant accident upon which the specified oxygen concentration limit is based. Permitting access to the drywell for leak inspections during a startup is judged prudent in terms of the added plant safety offered without significantly reducing the margin of safety. Thus, to preclude the possibility of starting the reactor and operating for extended periods of time with significant leaks in the primary system, leak inspections are scheduled during startup periods, when the primary system is at or near rated operating temperature and pressure. The 24-hour period to provide inerting is judged to be sufficient to perform the leak inspection and establish the required oxygen concentration. The primary containment is normally slightly pressurized during periods of reactor operation. Nitrogen used for inerting could leak out of the containment but air could not leak in to increase oxygen concentration. Once the containment is filled with nitrogen to the required concentration, no monitoring of oxygen concentration is necessary. However, at least once a week the oxygen concentration will be determined as added assurance.

4. Station Battery System

If one of the two 125 V battery systems or one of the two 250 V battery systems* is made or found to be inoperable for any reason, an orderly shutdown of the reactor shall be initiated and the reactor water temperature shall be reduced to less than 212°F within 24 hours unless such battery systems are sooner made operable

5. 24V Battery Systems

From and after the date that one of the two 24V battery systems is made or found to be inoperable for any reason, refer to Specificaton 3.2 for appropriate action.

* Applicable only to single station 250 V battery until completion of plant modification adding second 250 V battery (1983).

4. Station Battery System

a. Every week the specific gravity and voltage of the pilot cell and temperature of the adjacent cells and overall battery voltage shall be measured.

b. Every three months the measurements shall be made of voltage of each cell to nearest 0.01 volt, specific gravity of each cell, and temperature of every fifth cell.

c. Every refueling outage, the station batteries shall be subjected to a rated load discharge test. Determine specific gravity and voltage of each cell after the discharge.

5. 24V Battery Systems

a. Every week the specific gravity and voltage of the pilot cell and temperature of adjacent cells and overall battery voltage shall be measured.

b. Every three months the measurements shall be made of voltage of each cell to nearest 0.01 volt, specific gravity of each cell, and temperature of every fifth cell.

Bases 3.9:

The general objective is to assure an adequate supply of power with at least one active and one standby source of power available for operation of equipment required for a safe plant shutdown, to maintain the plant in a safe shutdown condition, and to operate the required engineered safeguards equipment following an accident.

AC for shutdown requirements and operation of engineered safeguards equipment can be provided by either of two active and either of two standby (two diesel generators) sources of power. As shown in Section 8 of the FSAR, power can be supplied to these plant auxiliary systems through either of two reserve transformers.

To provide for maintenance and repair of equipment and still have redundancy of power sources, the requirement of one active and one standby source of power was established. The plant's main generator is not given credit as a source since it is not available during shutdown.

The plant 250 V dc power is supplied by two batteries. Most station 250 V loads are supplied by the original station 250 V battery. A new 250 V battery has been installed for HPCI loads and may be used for other station loads in the future. Each battery is maintained fully charged by two associated chargers which also supply the normal dc requirements with the batteries as a standby source during emergency conditions. The plant 125 V dc power is normally supplied by two batteries, each with an associated charger. Backup chargers are available.

The minimum diesel fuel supply of 26,250 gallons will supply one diesel generator for a minimum of seven days of full load operation. Additional diesel fuel can normally be obtained within a few hours. Maintaining at least seven days supply is therefore conservative.

In the normal mode of operation, power is available from the off-site sources. One diesel may be allowed out of service based on the availability of off-site power and the daily testing of the remaining diesel generator. Thus, though one diesel generator is temporarily out of service, the off-site sources are available, as well as the remaining diesel generator. Based on a monthly testing period (Specification 4.9), the seven day repair period is justified. (1)

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(1) "Reliability of Engineered Safety Features as a Function of Testing Frequency", I. M. Jacobs, Nuclear Safety, Volume 9, No. 4, July - August 1968.

TABLE 3.13.1
SAFETY RELATED FIRE DETECTION INSTRUMENTS

Fire Zone	Location	Minimum Instruments Operable Heat	Flame	Smoke
1A	"B" RHR Room			3
1B	"A" RHR Room			3
1C	RCIC Room			3
1E	HPCI Room			2
1F	Reactor Building-Torus Compartment			11
2A	Reactor Bldg. 935' elev - TIP Drive Area			1
2B	Reactor Bldg. 935' elev - CRD HCU Area East			10
2C	Reactor Bldg. 935' elev - CRD HCU Area West			11
2E	Reactor Bldg. 935' - LPCI Injection Valve Area			1
3B	Reactor Bldg. 962' elev - SBLC Area			2
3C	Reactor Bldg. 962' elev - South			5
3D	Reactor Bldg. 962' elev - RBCCW Pump Area			4
4A	Reactor Bldg. 985' elev - South			4
4B	Reactor Bldg. 985' elev - RBCCW Hx Area			5
4D	SBGT System Room			2
5A	Reactor Bldg. 1001' elev - South			7
5B	Reactor Bldg. 1001' elev - North			3
5C	Reactor Bldg. - Fuel Pool Cooling Pump Area			1
6	Reactor Building 1027' elev			5
7A	Battery Room			1
7B	Battery Room			1
7C	Battery Room			1
8	Cable Spreading Room			7
12A	Turbine Bldg. - 911' - 4.16 KV Switchgear			3
13C	Turbine Bldg. - 911' elev - MCC 133 Area			1
14A	Turbine Bldg. - 931' - 4.16 KV Switchgear			2
15A	#12 DG Room & Day Tank Room		3	
15B	#11 DG Room & Day Tank Room		3	
16	Turbine Bldg. 931' elev - Cable Corridor			3
17	Turbine Bldg. 941' elev - Cable Corridor			3
19A	Turbine Bldg. 931' elev - Water Treatment Area			5
19B	Turbine Bldg. 931' elev - MCC 142-143 Area			1
19C	Turbine Bldg. 931' elev - FW Pipe Chase			1
20	Heating Boiler Room	1		
23A	Intake Structure Pump Room			3

5.0 DESIGN FEATURES

5.1 Site

A. The reactor center line is located at approximately 850,810 feet North and 2,038,920 feet East as determined on the Minnesota State Grid, South Zone. The nearest site boundary is approximately 1630 feet S 30° W of the reactor center line and the exclusion area is defined by the minimum fenced area shown in FSAR Figure 2.2.2a. Due to the prevailing wind pattern, the direction of maximum integrated dosage is SSE. The southern property line follows the northern boundary of the right-of-way for the Burlington Northern Railway.

5.2 Reactor

A. The reactor core shall consist of not more than 484 fuel assemblies.

B. The reactor core shall contain 121 cruciform-shaped control rods. The control rod material shall be boron carbide powder (B_4C) compacted to approximately 70% of theoretical density.

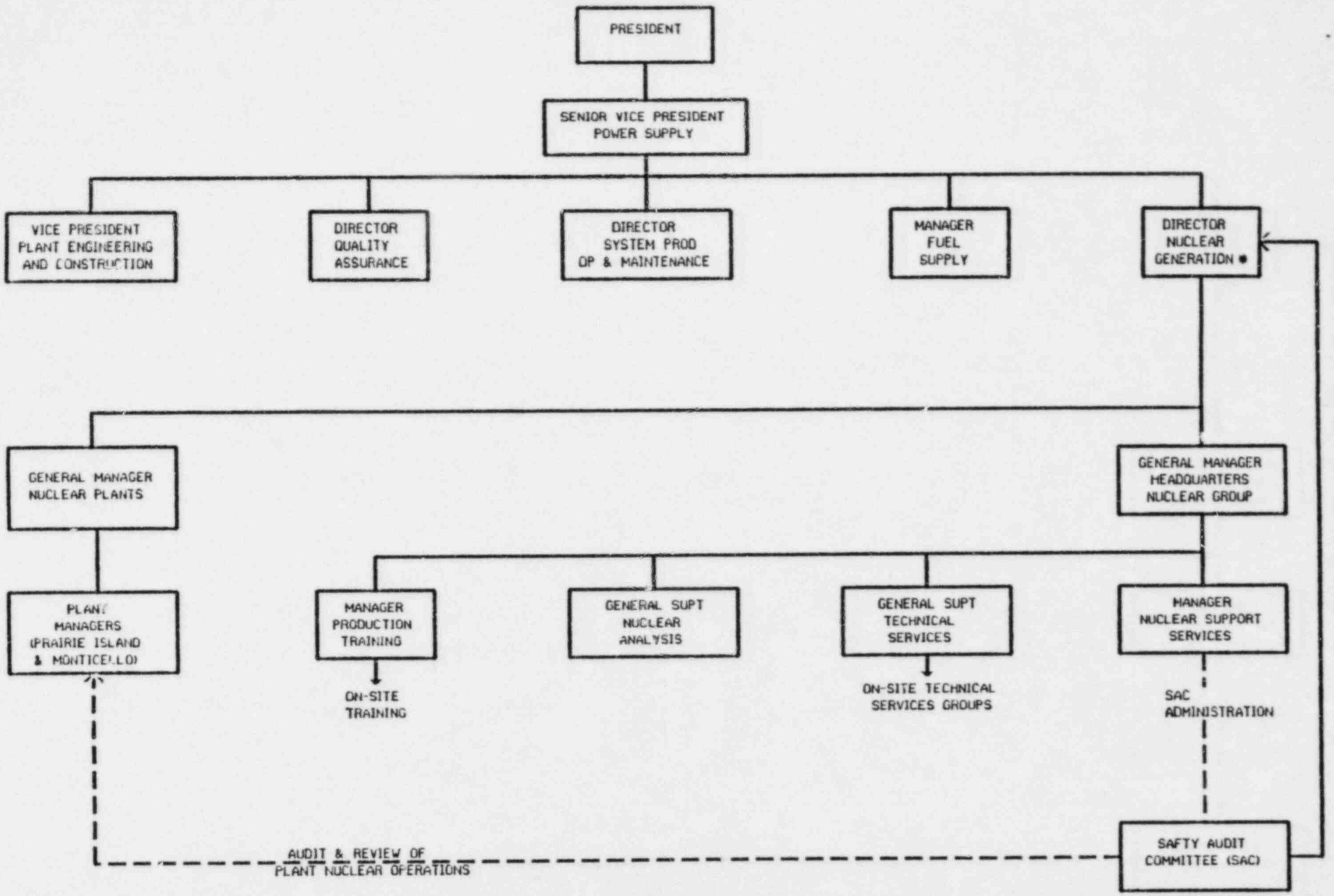
5.3 Reactor Vessel

A. The pressure vessel shall be designed for a pressure of 1250 psig and a temperature of 575°F. The coolant recirculation system shall be designed for a pressure of 1148 psig on suction side of pump and 1248 psig at pump discharge. The applicable design codes shall be as described in Sections 4.2.3 and 4.3.1 of the Monticello Final Safety Analysis Report.

5.4 Containment

A. The primary containment shall be of the pressure suppression type having a drywell and an absorption chamber constructed of steel. The drywell shall have a volume of approximately 134,200 ft^3 and is designed to conform to ASME Boiler and Pressure Vessel Code Section III Class B for an internal pressure of 56 psig at 281°F and an external pressure of 2 psig at 281°F. The absorption chamber shall have a total volume of approximately 176,250 ft^3.

E. A training program for individuals serving in the fire brigade shall be maintained under the direction of a designated member of Northern States Power management. This program shall meet the requirements of Section 27 of the NFPA Code - 1976 with the exception of training scheduling. Fire brigade training shall be scheduled as set forth in the plant training program.



* HAS THE RESPONSIBILITY FOR THE FIRE PROTECTION PROGRAM

FIGURE 6.1.1 NSP CORPORATION ORGANIZATION RELATIONSHIP TO ON-SITE OPERATING ORGANIZATION

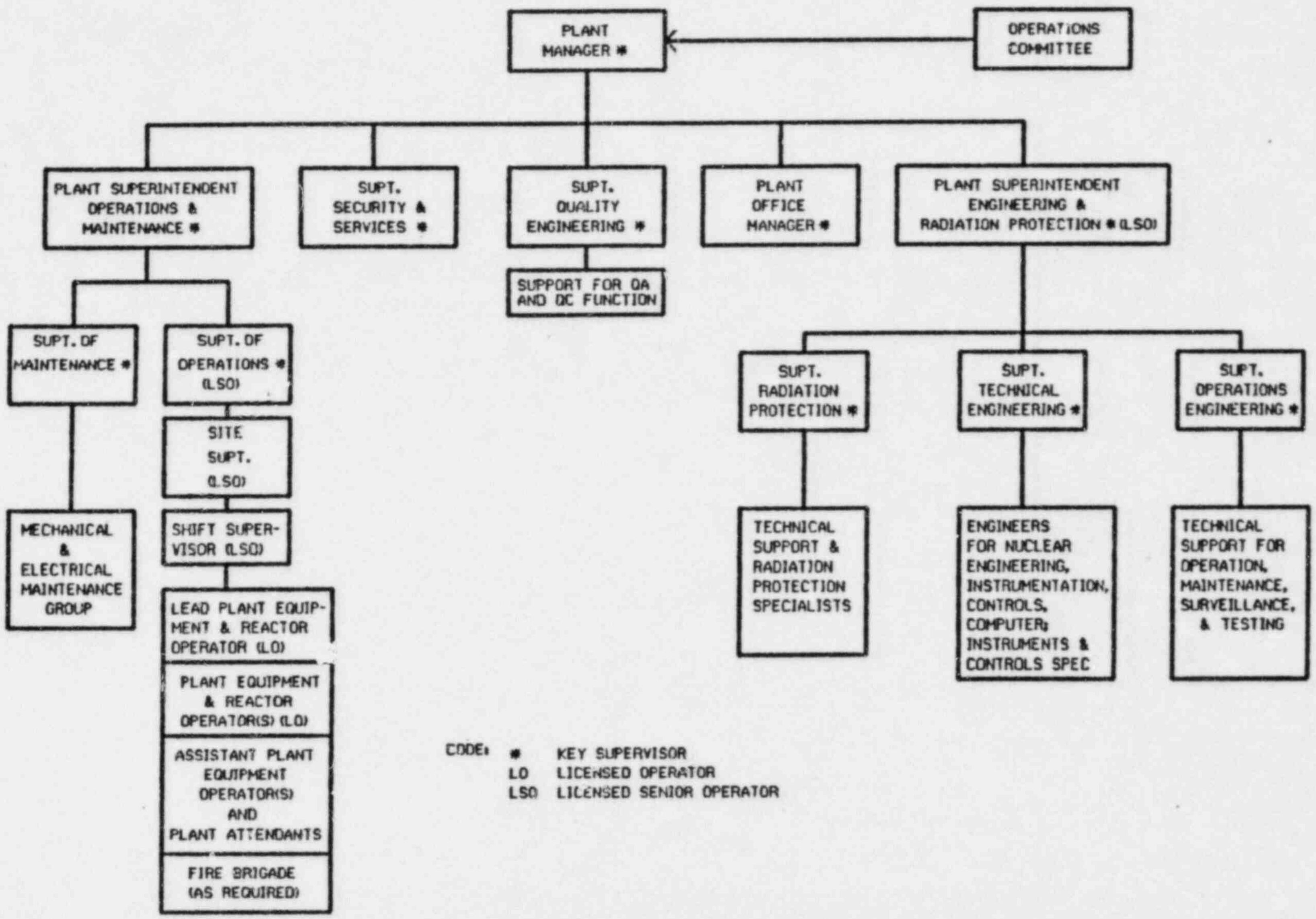


FIGURE 6.1.2 MONTICELLO NUCLEAR GENERATING PLANT FUNCTIONAL ORGANIZATION FOR ON-SITE OPERATING GROUP

b. When the nature of a particular problem dictates, special consultants will be utilized, as necessary, to provide expert advice to the SAC.

3. Meeting Frequency

The SAC shall meet on call by the Chairman but not less frequently than twice a year.

4. Quorum

a. No less than a majority of the permanent members or their alternates, including the SAC Chairman or Vice Chairman.

b. No more than a minority of the quorum shall be from groups holding line responsibility for the operation of the plant.

5. Responsibilities - The following subjects should be reported to or reviewed by the SAC:

a. Written safety evaluations of (1) changes in the facility, (2) changes to procedures, and (3) tests or experiments completed without prior Commission approval under the provisions of 10 CFR 50.59 to verify that such changes, tests or experiments did not involve a change in the Appendix A Technical Specifications or an unreviewed safety question as defined in 10 CFR 50.59.

b. Proposed changes to procedures, changes in the facility, and tests and experiments which may involve a change in the Appendix A technical specifications or an unreviewed safety question as defined in 10 CFR 50.59. Matters of this kind shall be referred to the SAC following their review by the onsite operating organization.

c. Proposed changes in Appendix A Technical Specifications or proposed license amendments relating to nuclear safety.

d. Violations of applicable codes, regulations, orders, Appendix A Technical Specifications, and license requirements or internal procedures or instructions having nuclear safety significance.

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

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

g. Revisions to the Facility Emergency Plan, the 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 Director Nuclear Generation, 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 Director Nuclear Generation.

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 Director Nuclear Generation, the General Manager Nuclear Plants, each member of the SAC, and others designated by the Chairman or Vice Chairman. There shall be a formal approval of the minutes.

9. Procedures

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

a. Subjects within the purview of the group.

b. Responsibility and authority of the group.

c. Mechanisms for convening meetings.

d. Provisions of use of specialists or subgroups.

e. Authority to obtain access to the nuclear power plant operating record files and operating personnel when assigned audit functions.

f. Requirements for distribution of reports and minutes prepared by the group to others in the NSP Organization.

B. Operations Committee (OC)

1. Membership

The Operations Committee shall consist of at least six (6) members drawn from the key supervisors of the on-site supervisory staff. The Plant Manager shall serve as Chairman of the OC and shall appoint a Vice Chairman from the OC membersip 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 quorum shall include 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 Updated Safety Analysis Report and having nuclear safety significance or which involve an unreviewed safety question as defined in 10 CFR 50.59.

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

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

e. All reported or suspected violations of Technical Specifications, operating license requirements, administrative procedures, or 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.

6.5 Plant Operating Procedures

Detailed written procedures, including the applicable check-off lists and instructions, covering areas listed below shall be prepared and followed. These procedures and changes thereto, except as specified below, shall be reviewed by the Operations Committee and approved by a member of plant management designated by the Plant Manager.

A. Plant Operations

1. Integrated and system procedures for normal startup, operation and shutdown of the reactor and all systems and components involving nuclear safety of the facility.

2. Fuel handling operations.

3. Actions to be taken to correct specific and foreseen potential or actual malfunction of systems or components including responses to alarms, primary system leaks and abnormal reactivity changes and including follow-up actions required after plant protective system actions have initiated.

4. Surveillance and testing requirements that could have an effect on nuclear safety.

5. Implementing procedures of the security plan.

6. Implementing procedures of the Facility Emergency Plan, including procedures for coping with emergency conditions involving potential or actual releases of radioactivity.

7. Implementing procedures of the fire protection program.

Drills on the procedures specified in A.3 above shall be conducted as a part of the retraining program.

B. Radiological

1.a. A Radiation Protection Program, consistent with the requirements of 10 CFR 20, shall be developed and followed. The Radiation Protection Program shall consist of the following:

(1) A Radiation Protection Plan, which shall be a complete and concise statement of radiation protection policy and program

(2) Procedures which implement the requirements of the Radiation Protection Plan

The Radiation Protection Plan and implementing procedures, with the exception of those non-safety related procedures governing work activities exclusively applicable to or performed by health physics personnel, shall be reviewed by the Operations Committee and approved by a member of plant management designated by the Plant Manager.

b. Paragraph 20.203 "Caution signs, lables, 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 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.

c. 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 a letter dated December 31, 1979, from L O Mayer, NSP, to Director of Nuclear Reactor Regulation, "Lessons Learned Implementation".

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

   c. Provisions for maintenance of sampling and analysis equipment.

   A program acceptable to the Commission was described in a letter dated December 31, 1979, from L O Mayer, NSP, to Director of Nuclear Reactor Regulation, "Lessons Learned Implementation".

EXHIBIT C

License Amendment Request Dated September 24, 1982

MONTICELLO NUCLEAR GENERATING PLANT
MAIN STEAMLINE TUNNEL TEMPERATURE SWITCHES
TECHNICAL SPECIFICATION MODIFICATION

Prepared for:

NORTHERN STATES POWER COMPANY
Minneapolis, Minnesota

Prepared by:
EDS Nuclear Inc.
Walnut Creek, California

November 1981

EDS Report No. 01-0910-1151, Rev. 2

EDS NUCLEAR INC.

REPORT APPROVAL COVER SHEET

Client: NORTHERN STATES POWER CO.

Project: MONTICELLO ENVIRONMENTAL ANALYSIS **Job Number:** 0910-001-471

Report Title: MONTICELLO NUCLEAR GENERATING PLANT MAIN STEAM TUNNEL TEMPERATURE SWITCHES TECHNICAL SPECIFICATION MODIFICATION

Report Number: 01-0910-1151 **Rev.** 0

The work described in this Report was performed in accordance with the EDS Nuclear Quality Assurance Program. The signatures below verify the accuracy of this Report and its compliance with applicable quality assurance requirements.

Prepared By: Nicolae T Morosi'ori for **Date:** 3-19-81
Benjamin R. Strong, Senior Technical Specialist, SED

Reviewed By: Lawrence J Metcalfe **Date:** 19 Mar 1981
Lawrence J. Metcalfe, Supervising Engineer, SED

Approved By: Timothy K. Snyder **Date:** 3-19-81
Timothy K. Snyder, Manager, Systems Engineering Division

REVISION RECORD

Rev. No.	Prepared	Reviewed	Approved	Approval Date	Revision
1	T.L. Laserman	[illegible]	D.F. Brosnan	9-28-81	Incorporate NSP comments
2	T.L. Laserman	[illegible]	D.F. Brosnan	11/2/81	Incorporate NSP's Comments

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1.0 INTRODUCTION

Northern States Power Company (NSP) requested EDS Nuclear to provide engineering analysis of the setpoint for the main steamline tunnel temperature switches (MSTS). These switches are installed at the Monticello Nuclear Generating Plant. Plant Technical Specification basis states that the temperature switches are capable of detecting a pipe break on the order of 5 to 10 gallons per minute (gpm) in the main steamline. Currently, the Technical Specification requires the temperature switch setpoint to be maintained at $\leq$ 200°F with a +2°F deviation.

The purpose of the EDS Nuclear engineering analysis is to determine the temperature in the area of the temperature switches that will result from a pipe break in the order of 5 to 10 gpm.

This report documents the EDS Nuclear scope of work, methods, results and conclusions. Also included is a list of the references and a description of the computer program used in the analysis. This report is a revision of the EDS Report No. 01-0910-1151, Rev. 1 issued in September, 1981. The revision includes Northern States Power Company's comments on the Rev. 1 report.

2.0 SCOPE

The scope of this report is an engineering evaluation of a main steamline pipe break in the main steamline tunnel at the Monticello Plant.

The size of the break considered is on the order of 5 to 10 gpm in either the main steamline or in the 3" main steam drain line.

The scope includes a computer analysis to determine the resulting temperature rise in the main steamline tunnel. Also included is an evaluation of the location of the temperature switches to detect the pipe break. The following temperature switches are considered:

TS 2-121A	TS 2-122A
TS 2-121B	TS 2-122B
TS 2-121C	TS 2-122C
TS 2-121D	TS 2-122D
TS 2-123A	TS 2-124A
TS 2-123B	TS 2-124B
TS 2-123C	TS 2-124C
TS 2-123D	TS 2-124D

The results of the analysis will provide the necessary data to determine what temperature switch setpoint will be adequate to maintain the existing level of safety function and break detection.

3.0 METHODS OF ANALYSIS

A break on the order of 5 to 10 gpm in the main steamline will discharge very low mass, high energy fluid into the main steamline tunnel. This would result principally in an increase in the sensible heat of the main steamline tunnel fluid. Heat will be removed from the main steamline tunnel fluid through the main streamline tunnel walls, floor and ceiling and by the fluid carried through the HVAC system. The increase in the main steamline tunnel sensible heat will result in an increase in temperature, but not a significant change in pressure. The blow out panel in main steamline tunnel would not be affected by this event.

The engineering analysis includes:

a. Assembly and review of input data

b. Computer analysis to determine the environmental conditions due to main steamline break.

The following sections describe each task in more detail.

3.1 ASSEMBLY AND REVIEW OF INPUT DATA

The information relevant to the main steamline tunnel area, including layout, piping, and HVAC drawings were assembled and reviewed (References 1 through 10).

The input data reviewed included:

a. Pipe ruptures identified in the main steamline tunnel.

b. System conditions.

c. Operations reports on MSTS function.

d. Elementary diagrams and isolation system logic diagram relating to MSTS function.

e. Applicable licensing materials.

The conditions and assumptions used for the evaluation of the main steamlines in the steamline tunnel are provided in Section 3.2.4.

A review of the applicable standards, regulations and licensing materials pertinent to the design and function of the MSTS (References 1 through 5) was performed to define the required limits of operation of MSTS. The existing Monticello Technical Specification describes the function of the temperature switches. Trips are provided on this instrumentation and when exceeded cause closure of Group 1 isolation valves. For large breaks, this signal is a backup to high steam flow instrumentation. For small breaks with the resultant small release of radioactivity, it provides isolation before the guidelines of 10CFR100 are exceeded (Reference 7).

3.2 COMPUTER ANALYSIS

Based on a postulated break in the main steamline on the order of 5 to 10 gpm, a computer model of the main steamline tunnel was developed to calculate the resulting pressure and temperature time histories (Reference 11).

The following are included in the model:

a. The HVAC System (Flow Path).

b. The heat transfered from the processed fluid into the main steamline tunnel.

c. The concrete walls in the main steamline tunnel.

d. The blowdown from the break in the main steamline.

3.2.1 COMPUTER MODEL DESCRIPTION

The computer program EDSFLOW was used to model the main steamline tunnel. EDSFLOW is the EDS Nuclear proprietary version of the RELAP4/MOD5 thermal-hydraulics computer program. The principal capabilities of the EDSFLOW computer code are described in Appendix A.

In the present analysis the code uses the Containment Option (air present) and represents the main steamline tunnel and HVAC system as a series of interconnected control volumes. Pipe break blowdown was input to the code and the flow between volumes was determined at each time step based on internal flow or homogeneous equilibrium critical flow.

The model used in this analysis is shown in Figure 3-1.

3.2.2 HEAT STRUCTURE MODELING

It was necessary to model heat-conducting structures in the main steamline tunnel to correctly determine the long term temperatures.

The concrete walls are modeled as heat sinks to represent the heat absorption capability of the main steamline tunnel structure. The heat transferred from the processed fluid is modeled as an additional heat source in the main steamline tunnel.

3.2.3 FLOW PATH MODELING

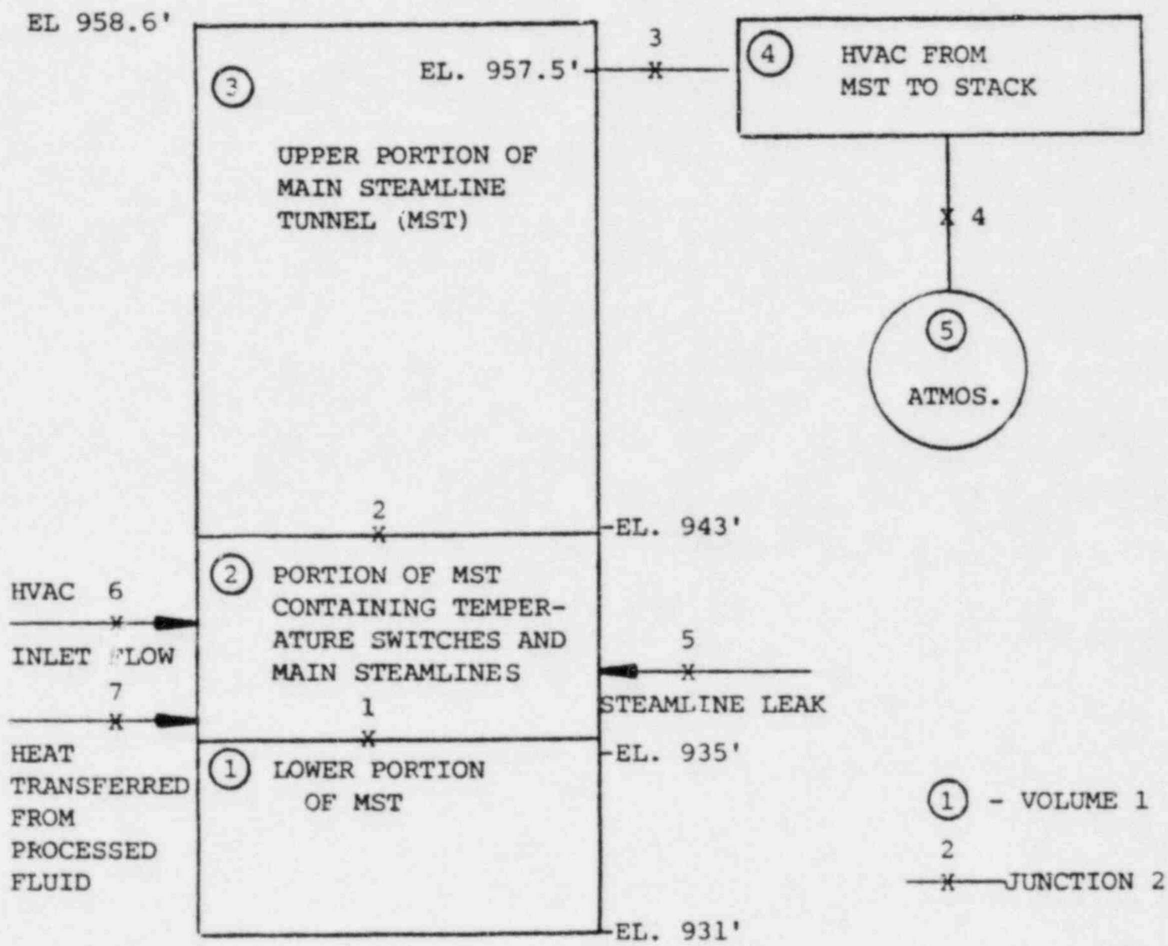
Normal junctions between volumes such as the HVAC ducting were modeled as vent paths to distribute the blowdown mass throughout the system. The blowout panel between the main steamline tunnel and the turbine building heater bay area was excluded from the model because the main steamline tunnel would not attain the pressure necessary to blow out the panel. This is confirmed by the results obtained in Reference 11. The minimum differential pressure required to blow out the panel is 0.25 psid (Reference 1).

3.2.4 BLOWDOWN FLUID PROPERTIES

The fluid properties in the main steamline and main steamline to condenser piping were taken for a reactor pressure at 102% power. This corresponds to a fluid pressure of 1040 psia and an enthalphy of approximately 1190 Btu/lbm.

FIGURE 3-1

EDSFLOW COMPUTER MODEL



4.0 RESULTS AND CONCLUSIONS

This section presents the results and conclusions of the engineering analysis performed to determine the adequacy of the MSTS to detect the specified break.

RESULTS

A break on the order of 5 to 10 gpm in the main steamline is sufficient to increase the main steamline tunnel temperature to 212°F.

During summer conditions, the 212°F temperature will be reached with a 5 gpm main steamline leak.

During the most limiting winter conditions the analysis results show the 212°F temperature threshold is reached due to a 9 gpm break in the main steamline.

It should also be noted that the current location of the MSTS array is in adequate proximity to the piping to provide sensing of the high temperature without the necessity of the discharged fluid heating the entire main steamline tunnel to 212°F.

CONCLUSIONS

The analysis conducted yielded the following conclusions:

1. Any setpoint, when added to the temperature switch deviation, totaling 212°F or less is acceptable. This setpoint will be adequate to maintain the existing level of safety function and break detection.

2. The Technical Specification (Table 3.2.6) may be revised by NSP to reflect this higher allowable temperature.

3. If the main steamline tunnel temperature switches are to be used to detect breaks other than in the main steamline, then analyses would have to be performed to assess the adequacy of the temperature switches for those functions.

5.0 REFERENCES

1. "Monticello Nuclear Generating Plant Environmental Effects Due to Pipe Rupture," EDS Report #01-0910-1137, Rev. 0, Dec. 1980

2. Letter of 2/15/80, Mr. C.B. Hogg (Bechtel) to Mr. M. Hammer (NSP) "Pipe Break Outside Containment Results," Bechtel Letter No. BLM:307/DCN:1953

3. "Postulated Pipe Failures Outside Containment," Monticello Nuclear Power Plant - Unit 1, with Supplements, Aug. 1973

4. United States Nuclear Regulatory Commission, NUREG-75/087 Standard Review Plan Section 3.6.1, "Plant Design For Protection Against Postulated Piping Failure in Fluid Systems Outside Containment," 11/24/75, with Attachments APCSB 3-1

5. Monticello Nuclear Power Station Unit-1, Final Safety Analysis Report, Sections 2.7 and 6.3

6. EDS Calculations Nos. 1-7 for Job Nos. 0910-001-224 and 372 Monticello NP-1, "Environmental Response Due to Pipe Rupture Outside Containment"

7. Monticello Nuclear Plant - Unit 1, Technical Specifications, Section 3.2 and Table 4.2.1, Rev. 52, 1/9/81.

8. Bechtel drawings for Monticello Nuclear Generating Plant - Unit 1, Job No. 5828.

   M-9 Rev 2, 11/4/70; Equipment Location Section A-A

   M-156 Rev 4, 8/21/70; Airflow Diagram Reactor Building Lower Part

   M-234 Rev 10, 11/18/74; Area-3 Piping Drawings Plan Below El 948'-0"

   M-242 Rev 12, 3/12/75; Area-3 Piping Drawings Section C-C

   M-515 Rev 5, 11/30/70; Reactor Bldg. H&V Plan at El. 935'-0"

   M-516 Rev 5, 11/30/70 Reactor Bldg. H&V Plan at El. 960'-0"

9. GE-729E856 sht 3 of 4, Primary Containment Isolation System.

10. GE-225A4669, Rev. 0 Instrument Data Sheet on Item No. 2-121 A to D (MSTS), 4/23/69.

11. EDS Calculation 0910-001-471-10.0, Rev. 0; Main Steam Tunnel Environment due to Leak in Main Steamline, September 1981.

APPENDIX A

EDSFLOW COMPUTER PROGRAM DESCRIPTION

APPENDIX A

The following section contains the EDSFLOW computer program abstract. This computer code was used by EDS to perform the compartment environmental thermal-hydraulic analysis for this project.

EDSFLOW COMPUTER PROGRAM DESCRIPTION

EDSFLOW is a modified version of the RELAP4/MOD5 computer code developed at the Idaho National Engineering Laboratory. It analyses the thermal-hydraulic behavior of light water reactor system subject to postulated transients such as those resulting from loss of coolant, pump failure, or nuclear power excursions.

EDSFLOW considers a thermal and hydraulic system as a series of interconnecting user-defined or control volumes. The program solves the mass and energy balances for volumes which contain one-dimensional homogenous fluid (water and steam) with the vapor and liquid phases in thermodynamic equilibrium. The momentum transport equation is solved at the interfaces or junctions between the control volumes. The code requires specific input in order to solve the conservation equations for both the modeled volume contents and the connecting junctions. Additional input is required to described component models which affect the mass, momentum, and energy balances.

The fluid dynamics portions of EDSFLOW solves the fluid mass, energy, and flow equations for the system being modeled. In order to provide a reasonable degree of versatility, a choice of the following basic forms of the flow equation is provided:

1. Compressible single-stream flow with momentum flux.

2. Compressible two-stream flow with one-dimensional momentum mixing.

3. Incompressible single-stream flow without momentum flux.

The compressible two-stream flow equation has four forms to represent different flow patterns of the streams. The fluid system to be analyzed by EDSFLOW must be specified by the user and is modeled by fluid volumes and junctions (flow paths) between volumes. Fluid volumes (control volumes) are used to represent the fluid in the system piping, plenums, reactor core, pressurizer, and heat exchangers. Any fluid volume may be chosen independently to represent a region of the system associated with a heat sink or source, such as fuel rods or a heat exchanger. The fluid volumes are connected by junctions which are used to transfer fluid into and out of fluid volumes. Options are available for selecting pump, valve, and bubble-rise models.

A heat-conductor model is used to transfer heat to or from the fluid in a fluid volume. The geometry and conditions of the heat conductor are specified by the user. Several options are also available for describing heat exchangers.

The main assumptions in EDSFLOW are:

1. The thermal-hydraulic equations used in EDSFLOW are based on the fundamental assumption that a two-phase fluid is homogenous and that the phases are in thermal equilibrium.

2. Multidimensional flow paths are approximated with one-dimensional equations.

3. The air assumed to be a perfect gas with a constant specific heat.

4. The EDSFLOW containment option allows the description of air flow along, or in combination with single or two-phase water flow. A homogenous equilibrium model is used in the sonic velocity calculation of air-steam-water mixtures.

5. The junction enthalpy is normally approximated as the average enthalpy upstream of the junction, as modified by the bubble-rise model.

6. The heat-conduction model used to account for the heat transfer to and from the fluid in given volumes is based on a one-dimensional numerical solution of heat-conduction equations.