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SCHWENCER,A. Licensing Branch 2

SUBJECT: Forwards response to Reactor Sys Branch request for addl info re open items,per 811007 telcon.Response will be incorporated into FSAR Amend 21.

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G02-81-0426
October 27, 1981

Docket No. 50-397

Mr. A. Schwencer, Chief
Licensing Branch No. 2
Division of Licensing
U.S. Nuclear Regulatory Commission
Washington D.C. 20555

Dear Mr. Schwencer:

Subject: SUPPLY SYSTEM NUCLEAR PROJECT NO. 2
NRC QUESTIONS AND OPEN ITEMS
REACTOR SYSTEMS BRANCH

Enclosed are sixty (60) copies of WNP-2 responses to the remaining Reactor Systems Branch questions. Also, enclosed are sixty copies of the open items from the WNP-2/NRC telephone conference on October 7, 1981.

Both the questions and the open items will be incorporated into Amendment 21 to the WNP-2 FSAR.

Very truly yours,

G. D. Bouchey

G. D. BOUCHEY
Deputy Director,
Safety and Security

GDB:CDT:ct

Enclosures

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B001
S 1/60

Q. 211.116
(5.2.2)

Provide the results of hydraulic calculations that show the Mach number, pressure, and temperature at various locations from upstream of the safety/relief valves to the suppression pool at maximum flow conditions. The concern is related to the potential for the development of damaging shock waves to the discharge piping. Include the effects of suppression pool swell variations on the operation of the safety/relief valves.

Response:

Table 211.116-1 lists the Mach number, pressure and temperature at selected locations downstream of the SRV. The conditions upstream of the valve are the steam stagnation pressure and density values listed in Table 211.116-2.

Under these conditions, the SRV orifice is choked and controls the flow in the discharge line. Sonic conditions (M-1) occur downstream of the SRV at the entrance to the quencher, due to the friction losses in the line. Since the critical pressure at the quencher inlet and pressure variations due to pool swell will not be able to reach the SRV to change its choked condition.

TABLE 211.116-1

TYPICAL SRVDL FLOW PARAMETERS AT
SELECTED NODES FOR MAXIMUM FLOW (LINE MS-RV-1A)

Distance from SRV (ft)	Mach. No.	Pressure (psia)	Wall Temp. (°F)
0.00 (SRV)	0.4116	388.8	385.9
15.10	0.4288	366.1	380.8
30.30	0.4502	342.3	375.4
45.40	0.4776	316.8	369.5
60.50	0.5151	288.7	362.7
75.60	0.5697	256.2	354.2
89.40	0.6524	219.1	343.7
104.50 (reducer)	1.0000	133.2	312.5
120.80	0.6750	142.1	308.1
136.50 (pipe exit)	1.0000	89.3	275.1
140.21 (quencher holes)	0.6460	22.9	218.8

TABLE 211.116-2

TYPICAL SRVDL DESIGN
AND INITIAL VALUES (LINE MS-RV-1A)

Steam	
Stagnation Density (lb_m/ft^3)	2.7636
Stagnation Pressure (psia)	1202.2
Mass Flow Rate (lb_m/sec)(122.5% rated flow)	301.0
Line Lengths (ft)	
To High Water Level	122.93
High Water Level To Top of Quencher Bonnet	13.55
Line Transition	
Location (ft)	104.5
Length (ft)	0.667
Size (in/in)	10/12 (sched. 80)
Number of Computational Nodes	100

Q. 211.118
(5.2.2)

Subsection 5.2.2.4.1 of the FSAR states that the pneumatic accumlator provided for each safety/relief valve has sufficient capacity to provide one safety/relief valve actuation. Figure 3.2-2 indicates that the air supply line upstream of the ball check valve is safety class G (non-safety grade). If the air line were to break upstream of the ball check valve, would there be an indication in the control room of this break and an indication of the accumulator status? If an indication is given, what operator action would be required? Also, show that accumulator capacity for one actuation is sufficient.

Response:

The details on Figure 3.2-2 were not intended to be colored to show safety class. Figure 3.2-21 shows that the correct safety class is 2 (safety grade).

Q. 211.119
(2.5)

Subsection 5.2.5.2 of the FSAR indicates that temperature and pressure monitoring devices are used as primary detection devices for unidentified leakage. Regulatory Guide 1.45 states that humidity, temperature, or pressure monitoring should be considered as alarms or indirect indications of leakage. Justify this exception to the criteria of Regulatory Guide 1.45. Demonstrate that the unidentified leak detection systems can detect leakage on the order of one gallon per minute in a one-hour periode.

Response:

The use of pressure and temperature as absolute indications of a leak has been clarified by adding the following statements to sections 5.2.5.2.c and 5.2.5.2.d. *

a. 5.2.5.2.c (added as last sentence to paragraph)
The accuracy and relevance of pressure measurement is a function of containment free volume and detector location, and should be compared to observed increases in liquid flow from sumps as well as indications from other leak detection devices.

b. 5.2.5.2.d (added as last sentence to paragraph)
The accuracy and relevance of temperature measurement is a function of containment free volume and detector location, and should be compared to observed increase in liquid flow from sumps as well as indications from other leak detection devices.

Humidity is indirectly monitored by measuring the flow rate of the floor drain sump for the drywell. A demonstration of the leak detection systems to detect leakage on the order of one gallon per minute in a one-hour period is delineated in Section 7.6.2.4.b, and the response to Question 211.002.

Related information is contained in the responses to Questions 211.003, 211.005.

*Draft FSAR page drawings attached.

Kevis

Q 211.119
80-202

c. Drywell Pressure Measurement

Insert #1 here

The drywell is at a slightly positive pressure during reactor operation. The pressure fluctuates slightly as a result of barometric pressure changes and outleakage. A pressure rise above the normally indicated values will indicate the presence of a leak within the drywell.

d. Drywell Temperature Measurement

The drywell cooling system circulates the drywell atmosphere through heat exchangers (air coolers) to maintain the drywell at its designed operating temperature and also provides cooling water to the air coolers. An increase in drywell atmosphere temperature would increase the temperature rise in the service water passing through the coils of the air coolers. Thus, an increase in the service water temperature difference between inlet and outlet to the air coolers will indicate the presence of reactor coolant or steam leakage. Also, a drywell ambient temperature rise will indicate the presence of reactor coolant or steam leakage. A temperature rise in the drywell is detected by monitoring the drywell temperature at various elevations, inlet and outlet air to the coolers, and the closed cooling water temperature increase between inlet and outlet to the coolers.

Insert #2 here

e. Drywell Air Sampling

The drywell air sampling system is used to supplement the temperature, pressure, and flow variation method described previously to detect leaks in the nuclear system process barrier. The system continuously monitors the drywell atmosphere for airborne radioactivity. The sample is drawn from the drywell. A sudden increase of activity, which may be attributed to steam or reactor water leakage, is annunciated in the control room. (Refer to Containment Indications, 7.5.1.5).

Insert #1 to Page 5.2-39:

The accuracy and relevance of pressure measurement is a function of containment-free volume and detector location and should be compared to observed increases in liquid flow from sumps as well as indications from other leak detection devices.

Insert #2 to Page 5.2-39:

The accuracy and relevance of temperature measurement is a function of containment-free volume and detector location and should be compared to observed increase in liquid flow from sumps as well as indications from other leak detection devices.

Q. 211.120
(5.2.5)

Subsection 7.6.1.13.7 of the FSAR states that the same leak detection monitor (a three-channel unit) will detect both airborne particulate and gaseous activities in the drywell atmosphere using scintillation detectors.

Explain how these two different types of airborne activities are separated by the monitor. Justify taking credit for both monitoring techniques in subsection 7.6.2.4.2.1.2 while using the same device. State the sensitivity and response time of the radioactivity monitor.

Response:

The FSAR has been revised such that the leak detection monitor is now addressed in subsection 7.5.1.5, rather than 7.6.1.13.7. In addition, the information contained in subsection 7.6.2.4.2.1.2 relative to leak detection monitoring is now contained in subsection 7.6.2.4.b.

The sample is drawn into the sample system by its vacuum pump. Flow control is provided to insure proper sample flow. The sample flow path is from the sample point inside the primary containment, through the inlet isolation valve to the particulate monitor chamber. Here the sample is passed through a moving filter tape where the particulate matter is deposited on the tape while allowing the noble gases to pass through. The filter tape then moves across the face of a scintillation detector for analysis.

The gaseous sample, after removal particulate matter passes into a volume chamber where a second scintillation detector checks activity. Activity at this point will be due to noble gases.

The sample gas then proceeds through the flow control device, vacuum pump, return line isolation valve and is discharged back into the primary containment.

Detector description and sensitivity are as follows:

Particulate Detectors

The particulate detector is a beta scintillation type positioned near a moving tape filter collector assembly. Tape linear feed rates are adjustable from 1/4" to 1" per hour. The detector has a sensitivity of 10-10 uCi/cc concentration of activity in a 2 mR/hr background at 1"/hr tape feed rate with approximately 3 CFM of sample gas flowrate.

Noble Gas Detectors

The noble gas detector is a beta scintillation type and has a sensitivity of 1 x 10-6 uCi/cc for Kr-85.

Detector response times have previously been addressed in the response to Q. 211.006.

Q. 211.132
(4.6.1.1.2.4.2.1)

Describe provisions to protect the Hydraulic Control Units (HCU's) and Control Rod Drives (CRD's) from damage due to inadvertent failure of either the automatic backwash suction filter, the pump filters, or the drive water filter. If none exist provide justification that inadvertent failure of any filter will not cause damage to the HCU's and CRD's.

Response:

The filters used on the CRD system are of a rugged design and failure of the filters are not considered likely. Alarms are provided to give an early warning to the operator that maintenance is required.

The only known mode of failure of the filter element is for it to collapse due to high differential pressure. The CRD pump suction filter can withstand a maximum differential pressure of 20 psi and an alarm indicates in the control room high suction filter differential pressure at 8 psi. The filter element is additionally protected and strengthed by a stainless steel, perforated center tube. The CRD pump discharge filter can withstand a maximum differential pressure of 300 psi and an alarm indicates in the control room high differential pressure at 20 psi. The filter element is constructed entirely of stainless steel.

The primary source of CRD systems pump suction and discharge filters were bypassed completely, possible presence of corrosion particles would not affect the reliablity of the scram function of the CRD system. The presence of corrosion particles may accelerate wear of the drive components over a period of time. However, such wear is not a safety concern since this degradation in drive performance already occurs during normal rod operations and is detectable.

The minimum performance requirements of the drives reactor operation is specified in the technical specified in the technical specification. If the limiting conditions for operation are not met, the CRD is considered inoperative and the subsequent operation of the reactor is adjusted, as required, to account for the inoperative drive.

Q. 211.171
(15.0)

Provide an analysis of the "Loss of Instrument Air" transient.

Response:

Although a complete analysis of the "Loss of Instrument Air" transient has not been performed, an expected sequence of events and operator actions for this event are provided below.

Recent operating experience indicates that complete loss of instrument air is a remote possibility, since there is enough instrument air stored to provede backup for safety- related air operated equipment. However, reports of partial loss of instrument air appears to have had no serious effects on reactor components, although it occurs with a moderate frequency.

The Compressed Air Systems are described in FSAR Subsection 9.3.1; with the Control and Service Air System in Subsection 9.3.1.2.1, and the Containment Instrument Air System in Subsection 9.3.1.2.1.

The Containment Instrument Air System consists of two, 100% capacity compressors aumented with nitrogen bottles for the ADS accumulators. The Control and Service Air System consits of three 50% capacity compressors.

However, in the event instrument air is lost from these redundant sources, the following events could be expected to occur (in a secquence dependent on the location and type of failures).

1. Control Rod Drive System - The scram inlet and outlet valves will open, shutting down the reactor. The CRD flow control valve will close to approximately 2% open. The drain and vent valves for the Scram Disgharge Volume will close.

   The main turbine pressure control system will maintain reactor pressure after the reactor is shutdown until the turbine control valves are closed. If the mode switch is still in the "Run" mode the main steam isolation valves will close and produce a scram signal as the reactor pressure decreases below 850 psi.

2. Reactor Water Cleanup System - All air-operated cleanup filter deminerlizer valves and the reject valve to radwaste or the main condensers will close upon loss of air.

3. Standby Liquid Control - The level indication for the storage tank will decrease to zero.

4. Main steamline isolation valves (MSIV) will close. MSIV will also receive a close signal due to loss of condenser vacuum.

5. Main Steam safety relief valves will not open as a direct result of loss of air supply. There is sufficient air in each relief accumulator to provide one actuation of each relief valves following MSIV failure. Long term reactor pressure control is provided by the safety feature (spring relief) of the safety relief valves.

6. Containment atmosphere control valves and containment ventilation isolation valves fail closed on loss of instrument air.

7. The steam supply valves to the steam jet air ejectors will close, eventually resulting in loss of condensor vacuum.

8. Spent fuel pool cooling and cleanup system - The demineralized makeup to the pool skimmer surge tank will fail closed, but Class IE level instrumentation is provided with a safety-related makeup source (standby service water). Also, the fuel pool filter/demineralizer bypass valve will open allowing recirculation directly back to the fuel pool.

9. The ventilation supply isolation dampers to the secondary containment fail closed.

10. The standby gas treatment system will align itself to take suction from the secondary containment.

11. The RCIC steamline drain and RHR heat exchanger steam supply control valves will close. The RHR heat exchanger steam supply is normally closed by a motor operated valve.

12. Loss of instrument air has no effect on HPCS.

13. All testable check valves in the systems - Testabiltiy, not operability, would be lost to those testable check valves supplied by the Containment Instrument Air or Control and Service Air Systems.

14. The minimum flow bypasses for the condensate, condensate booster, and feedwater pumps will open, bypassing feedwater to the condenser. This will cause the reactor water level to drop to level 3, thereby initiating a scram signal.

15. Non-safety systems which do not affect safe plant shutdown are affected by complete or partial loss of instrument air. However, complete or partial loss of air does not adversely affect any safety systems required to safety shutdown the plant.

16. Automatic hotwell level control is lost as the air-operated makeup/reject valves fail closed.

The following is the sequence of operator actions expected during the course of the event. The operator should:

1. Confirm that the reactor has become subcritical.

2. Initiate a scheduled surveillance of the standby liquid control storage tank to confirm proper water level and add water manually as required from the clean demineralized water system.

3. Operate RCIC and/or HPCS according to normal procedures to maintain normal reactor water level.

4. Continue the cooldown of the reactor with the RHR system, after reactor pressure and temperature have decreased to the operating limits of RHR.

5. Upon receipt of alarm of loss of 1/4" H_2O vacuum in reactor building (see Item 9 above), manually initiate operation of the standby gas treatment system.

6. Manually makeup water to the closed cooling water system and the fuel pool system as required.

7. Manually control hotwell level as required.

Loss of the instrument air system will result in the shutdown of the reactor due to the opening of the control rod scram valves and the closing of the main steamline isolation valves. The failure of instrument air will not interfere with the safe shutdown of the reactor since all equipment using instrument air is designed to fail to to a position that is consistent with the safe shutdown of the plant. Although specific operator action to shutdown the plant safety is not required after a loss of instrument air, the plant evergency procedures will reflect the best actions to be taken.

Q. 211.185
(15.3.3)

For the recirculation pump seizure accident we note in Table 15.3-5 that credit is taken for non-safety-grade equipment (L8-trip) to terminate this design basis accident (DBA). Section 15.3.3 of the Standard Review Plan requires use of only safety-grade equipment to mitigate the consequences of this DBA and that the safety functions be accomplished assuming the worst single failure of an active component. Re-evaluate this DBA with the above specific criteria and provide the resulting ΔCPR, peak vessel pressure, and percentage of fuel rods in boiling transition. Assume coincident loss of offsite power as required by the Standard Review Plan.

Response:

See the response to Question 211.092.

Q. 211.196
(6.3)

Operating experience has shown that where thermocouples are used to verify ADS valve operation a "false" temperature increase may be indicated even though the valve has not operated. A direct indication of valve position or flow must be used. Specify how you will meet this requirement.

Response:

The WNP-2 position for indicating ADS/SRV valve position is presented in Appendix B Section II.D.3 of the FSAR. An acoustic monitoring system is being provided.

Q. 211.199
(6.3)

Discuss the design provisions that permit manual override on the ECCS subsystems once they have received an ECCS initiation signal. Also, include a discussion of any lockout devices or timers that prevent the operator from prematurely terminating ECCS functions. If there are plant procedures to cover this situation, indicate briefly what instructions are provided.

Response:

Each ECCS subsystem (LPCI, LPCS, HPCS, ADS) is provided with manual override logic which allows the operator to terminate or delay automatically initiated core cooling functions by closing the injection valve or stopping the pump or delaying system actuation. This is necessary in case an ECCS has failed or requires isolation to protect suppression pool inventory, or whose function is no longer needed when other core cooling functions are successful (thus reducing the long-term) load on diesel generators). Other manual overrides are provided to allow the operator to terminate the core cooling function of a system such as RHR allowing the system to be utilized in other modes of post-accident operation (e.g., Suppression Pool Cooling, Containment Spray).

The plant operators are instructed to use the manual override controls only when the core cooling function has been or will be successful. For example, the operator will not terminate the LPCS unless assured by at least two independent reactor vessel water level indications that water level is restored. The high drywell pressure initiation signal may still be above the trip point. For the case of the ADS, the operator can delay initiation indefinitely (105 seconds at a time). However, this will only be done when the operator is assured that reactor vessel water level is being restored by the HPCS, again by consulting at least two independent water level indications. The operator will terminate the LPCI mode of RHR to enter another mode of RHR only after consulting the water level indication and the availability of other core cooling systems.

There is only one time delay/lockout which prevents the operator from prematurely terminating an ECCS function. That is the 10 minute timer within the LPCI logic which prevents the operator from moving the RHR heat exchanger bypass valves E12-F048A/B from their full open position.

For all ECCS manual overrides (except ADS), automatic system actuation will not reoccur unless the initial initiation signals (high drywell pressure, low water level) return to normal and the logic is reset. The ADS logic will automatically reset when the 105 second time delay is complete.

Q. 211.206
(6.3)

The ECCS discharge line fill systems require additional clarification. Provide the jockey pump characteristics (head, capacity, etc.) and the maximum expected leakage rates for each system discharge piping.

Response:

The jockey pumps are shown on the following ECCS system flow diagrams:

FSAR FiGURE NO.	SYSTEM	PUMP IDENTIFICATION
3.2-7	High Pressure Core Spray	HPCS-P-3
3.2-7	Low Pressure Core Spray	LPCS-P-2
3.2-8	Reactor Core Isolation Cooling	RCIC-P-3
3.2-6	Residual Heat Removal	RHR-P-3

All four pumps are identical; their characteristics (head, capacity, etc.) are given in Table 211.206-1.

The jockey pumps pressurize the following piping within the valves listed in Tables 211.206-2 through 211.206-5.

JOCKEY PUMP DESIGNATION	PIPING PRESSURIZED	VALVE LISTING
HPCS-P-3	Discharge piping of HPCS pump	Table 211.206-2
LPCS-P-2	Discharge piping of LPCS pump and RHR pump 2A	Table 211.206-3
RCIC-P-3	Suction and discharge piping of RCIC pump	Table 211.206-4
RHR-P-3	Discharge piping of RHR pump 2B and RHR pump 2C	Table 211.206-5

The leakage rates, estimated at 10cc/hour per inch of nominal valve diameter, are summarized in the following for the valves listed in Tables 211.206-2 through 211.206-2 through 211.206-5.

JOCKEY PUMP DESIGNATION	LEAKAGE RATES OF VALVES CONNECTED TO JOCKEY PUMP DISCHARGE PIPING
HPCS-P-3	530 cc/hour
LPCS-P-2	1340 cc/hour
RCIC-P-3	380 cc/hour
RHR-P-3	1540 cc/hour

TABLE 211.206-1

JOCKEY PUMP CHARACTERISTICS

A. Pump Data

Design Flow	25 gpm
Design Head	200 feet
Manufacturer	Crane Co. Figure 3065, size 2 x 9½

Certified Pump Curve Data

gpm	Head, ft. HPCS-P-3	LPCS-P-2	RCIC-P-3	RHR-P-3
0	212	214	209	212
10	210	210	207	210
20	207	207	205	206
30	203	203	202	202
40	197	197	195	197
50	190	188	185	189
60	182	178	180	181
70	170	162	168	169
80	155	161	155	156

B. Motor Data (Nameplate rating)

HP	15	Full load, amp	18.5
rpm	3500	Type	DP
phase	3	Frame	256T
Hertz	60	Manufacturer	Westinghouse
volts	110		

HPCS

TABLE 211.206-2

LIMITS OF HPCS JOCKEY PUMP PRESSURIZATION

VALVE IDENTIFICATION	VALVE TYPE	VALVE FUNCTION	DESIGN LEAKAGE RATE (cc/hr.)
HPCS-V-23	M.O. 12" Globe	Containment isolation for HPCS pump discharge to suppression pool (X-49)	120
HPCS-V-4*	M.O. 12" Gate	Containment isolation for HPCS pump discharge to RPV (X-6)	120
HPCS-V-10	M.O. 10" Globe	System isolation for HPCS pump discharge to condensate storage tank	100
HPCS-V-24	16" Check	HPCS pump discharge line check	160
HPCS-V-26	Manual 3" Gate	HPCS pump discharge line check valve by-pass	30
Insert A		Total design leak rate, cc/hr	~~[illegible]~~ 570

* Leaks only if reactor is at low pressure

Insert A

HPCS

TABLE 211.206-2 (cont.)

Valve ID	Valve Type	Valve Function	Design Leakage Rate (cc/hr)
HPCS-RV-35	1" Relief Valve	HPCS-P-3 suction Relief Valve	10.
HPCS-V-3	Manual 3" Gate	Condensate Flush Supply Inlet Block	30.
~~HPCS-[illegible]~~	~~[illegible]~~	~~[illegible]~~	~~[illegible]~~ ~~[illegible]~~ ~~570.~~ ~~[illegible]~~

PTM 5/27/81

TABLE 211.206-3

LIMITS OF LPCS JOCKEY PUMP PRESSURIZATION

VALVE IDENTIFICATION	VALVE TYPE	VALVE FUNCTION	DESIGN LEAKAGE RATE (cc/hr.)
LPCS-V-3	16" Check	LPCS pump discharge line check	160
LPCS-V-4	Manual 3" Gate	LPCS pump discharge line check valve by-pass	30
LPCS-V-12	M.O. 12" Globe	Containment isolation for LPCS pump discharge to suppression pool (X-63)	120
LPCS-V-5 *	M.O. 12" Gate	Containment isolation for LPCS pump discharge to RPV (X-8)	120
RHR-V-31A	18" Check	RHR pump 2A discharge line check	180
RHR-V-72A	Manual 3" Gate	RHR Loop A flush out to radwaste	30
RHR-V-24A	M.O. 18" Globe	RHR Loop A test line to suppression pool (X-47)	180
RHR-V-16A	M.O. 16" Gate	Loop A isolation for containment spray (X-11A)	160
RHR-V-42A *	M.O. 14" Gate	Loop A isolation for RPV discharge (X-12A)	140
RHR-V-53A *	M.O. 12" Globe	Loop A isolation for reactor recirculation piping intertie (X-19A)	120
RHR-V-27A	M.O. 6" Gate	Loop A isolation for suppression pool spray (X-25A)	60
RHR-V-11A	M.O. 4" Gate	Loop A isolation to supp. pool (flow during RHR exchanger cond. mode (X-47))	40
		Total estimates design leakage, cc/hr:	~~[illegible]~~ 1695

insert B

* Leaks only if reactor is at low pressure.

LPCS - RHR A

Insert B

TABLE. 211.206-3 (cont)

Valve ID	Valve Type	Valve Function	Design Leakage Rate (cc/hr)
LPCS-V-25	Manual 3" Gate	Condensate Flush Supply Inlet Block	30.
LPCS-RV-18	1½" Relief Valve	LPCS-P-1 Test Line Relief Valve	15.
RHR-V-122A	18" Check Valve	Steam Supply to RHR Heat Exchanger A	180.
RHR-V-74A	M.O. 2" Globe	RHR Heat Exchanger A vent-shell side	20.
RHR-RV-1A	¾" Relief Valve	RHR Test Line - Loop C Relief Valve	7.5
RHR-V-714A	Manual ¾" Globe	Drain for RHR Heat Exchanger A Level Transmitter	7.5
RHR-V-80A	Manual ¾" Globe	RHR Heat Exchanger A Drain Connection	7.5
RHR-V-26A	M.O. 4" Gate	RHR Heat Exchanger A Outlet to RCIC	40.
RHR-V-60A	Sol. O. ¾" Gate	Process Sampling Connection to Heat Exchanger A Outlet	7.5
RHR-RV-25A	1" Relief Valve	RHR-Test Line Loop A	10.
RHR-V-63A	Manual 3" Gate	Flush Supply for Shutdown Cooling Loop A	30
			~~1545.5~~ ~~1495.0 cc/hr~~

PMM 5/27/81

TABLE 211.206-4

LIMITS OF RCIC JOCKEY PUMP PRESSURIZATION

VALVE IDENTIFICATION	VALVE TYPE	VALVE FUNCTION	DESIGN LEAKAGE RATE (cc/hr.)
RCIC-V-11	8" Check	Prevent reverse flow into condensate storage tank supply	80
RCIC-V-30	8" Check	Prevent reverse flow into suppression pool supply (X-33)	80
RCIC-V-13*	M.O. 6" Gate	Containment isolation for RCIC pump discharge to RPV (X-2)	60
RCIC-V-22	M.O. 6" Gate	System isolation for RCIC pump discharge to condensate storage tank	60
RCIC-V-19	M.O. 2" Globe	Containment isolation for RCIC pump discharge to suppression pool	20
RHR-V-26A	M.O. 4" Gate	System isolation to RHR Loop A	40
RHR-V-26B	M.O. 4" Gate	System isolation to RHR Loop B	40
insert C →			
		Total estimated design leakage, cc/hr:	~~250~~ 575

* Leaks only if reactor is at low pressure

RCIC

Insert C

TABLE 211. 206 - 4 (cont.)

Valve I.D	Valve Type	Valve Function	Design Leakage Rate (cc/hr)
RCIC-RV-17	1" Relief Valve	RCIC-P-3 Discharge Pressure Relief Valve	10.
RCIC-V-606	Manual 3/4" Globe	2" RCIC (5)-1 Vent	7.5
RCIC-V-47	Manual 2" Check Valve	RCIC Condensate Pump Discharge	20.
RCIC-V-51	Manual 1" Globe	RCIC-P-1 Pump Casing Drain.	10.
RCIC-V-104	Manual 3/4" Globe	RCIC-P-1 Pump Casing Vent	7.5
RCIC-V-46	MO 2" Globe	Auxiliary Cooling Supply	20.
RHR-RV-36	6" Relief Valve	RHR Steam Condensing Mode Return	60.
			~~135.~~
			+ ~~380.~~
			~~515.~~

PTM 6/27/81

TABLE 211.206-5

LIMITS OF RHR JOCKEY PUMP PRESSURIZATION

VALVE IDENTIFICATION	VALVE TYPE	VALVE FUNCTION	DESIGN LEAKAGE RATE (cc/hr.)
RHR-V-31B	18" Check	RHR pump 2B discharge line check	180
RHR-V-72B	Manual 3" Gate	RHR Loop B flush out to radwaste	30
RHR-V-24B	M.O. 18" Globe	RHR Loop B test line to suppression pool (X-48)	180
RHR-V-16B	M.O. 16" Gate	Loop B isolation for containment spray (X-11B)	160
RHR-V-42B *	M.O. 14" Gate	Loop B isolation for RPV discharge (X-12B)	140
RHR-V-53B *	M.O. 12" Globe	Loop B isolation for reactor recirculation piping (X-19B)	120
RHR-V-27B	M.O. 6" Gate	Loop B isolation for suppression pool spray (X-25B)	60
RHR-V-11B	M.O. 4" Gate	Loop B isolation to suppression pool (X-48) (RHR ht exch cond. mode)	40
RHR-V-23	M.O. 6" Globe	Reactor Head spray (X-2)	60
RHR-V-49	M.O. 4" Gate	System isolation for RHR pump 2B discharge to radwaste	40
RHR-V-31C	18" Check	RHR pump 2C discharge line check	180

* Leaks only if reactor is at hot conditions

TABLE 211.206-5 (continued)

VALVE IDENTIFICATION	VALVE TYPE	VALVE FUNCTION	DESIGN LEAKAGE RATE (cc/hr.)
RHR-V-114	Manual 3" Gate	RHR Loop C flushout to radwaste	30
RHR-V-21	M.O. 18" Globe	RHR Loop C test line to suppression pool (X-26)	180
RHR-V-42C	M.O. 14" Gate	Loop C isolation for RPV discharge (X-12C)	140

Insert D

Total estimated design leakage, cc/hr: ~~[illegible]~~ 2160

RHR B-e

TABLE 211.206-5 (cont)

Insert D

Valve ID	Valve Type	Valve Function	Design Leakage Rate (cc/hr)
RHR-V-122B	18" Check Valve	Steam Supply to RHR Heat Exchanger B	180.
RHR-V-74B	MO 2" Globe	RHR Heat Exchanger 1B Vent - Shell Side	20.
RHR-V-24B	MO 4" Gate	RHR Heat Exchanger 1B Outlet to RCIC	40.
RHR-RV-1B	3/4" Relief Valve	RHR Heat Exchanger 1B Relief Valve	7.5
RHR-V-71B	Manual 3/4" Globe	Drain for RHR Heat Exchanger 1B Level Transmitter	7.5
RHR-V-80B	Manual 3/4" Globe	RHR Heat Exchanger 1B Drain Connection	7.5
RHR-V-60B	Sal. O. 3/4" Gate	Process Sampling Connection to RHR Heat Exchanger 1B	7.5
RHR-V-89	A.O. 14" Check Valve	RHR Tieline to Service Water	140.
RHR-V-104	Manual 10" Globe	RHR Tieline to Fuel Pool Cooling System	100.
RHR-RV-25B	1" Relief Valve	RHR Test Line Loop B Relief Valve	10.
RHR-V-63B	Manual 3" Gate	Flush Supply to Shutdown Cooling Loop B	30.
RHR-RV-25C	1" Relief Valve	Test Line Loop C Relief Valve	10.
RHR-V-63C	Manual 3" Gate	Flush Supply - Loop C Return to RPV	30.
RHR-V-86	Manual 3" Gate	Flush Supply to Rx Head Spray	30.

PTM 5/27/81

Q. 211.213

Calculations of NPSH available to ECCS pumps in BWRs are normally provided with reference to the pump suction. We are concerned that under certain post-accident conditions the potential may exist for damage to ECCS pumps from cavitation because of local flashing in the system suction lines. The potential can result, for example, from local elevation changes in the piping runs. Calculations of NPSH available at the pump suction may erroneously assume liquid continuity up to the point of pump suction. Provide an analysis with calculations which demonstrates that the NPSH available at all points in all safety-related pump suction piping is adequate to preclude local flashing and pump cavitation under the worst postulated conditions.

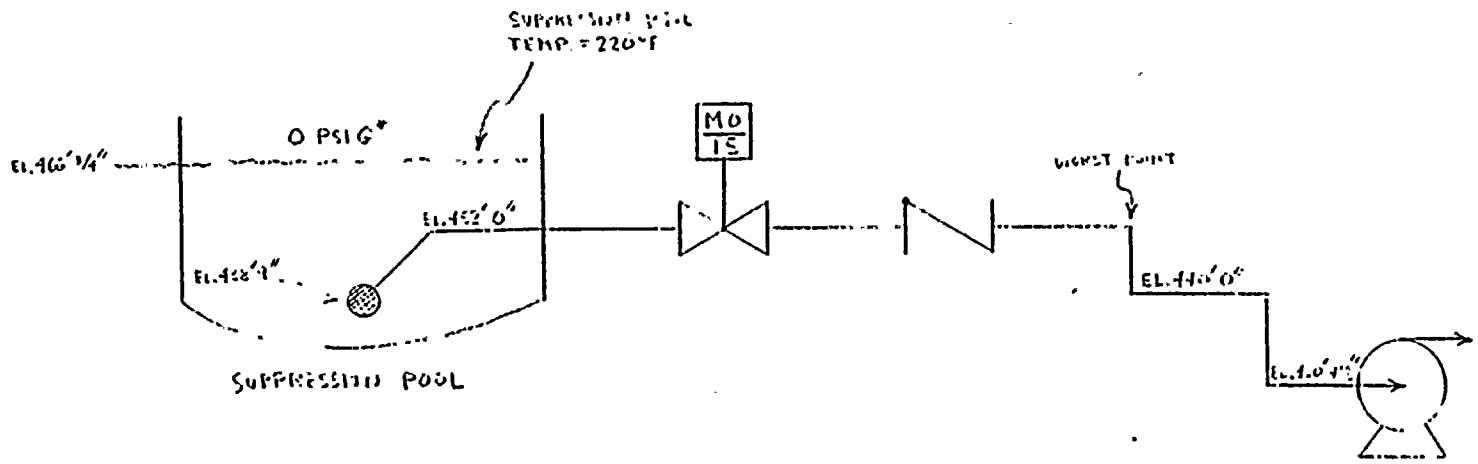
Response:

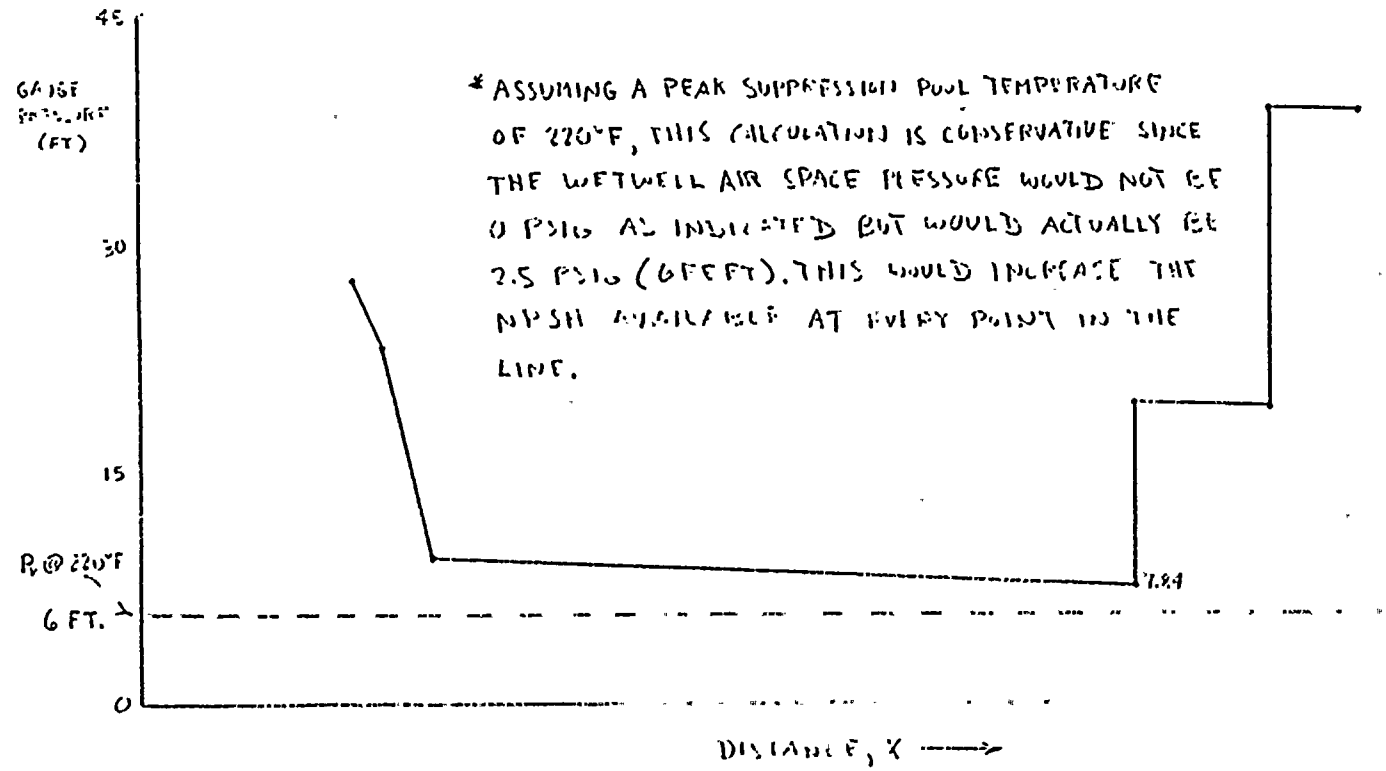
The ECCS systems which are involved are the RHR, LPCS, and HPCS systems. The RCIC system is also considered. Supply to the suction of the pumps comes from condensate storage or from the suppression pool. In the worst case, pump suction would be drawn from the suppression pool at high temperatures.

For each system, assuming a peak suppression pool temperature of 220°F, a plot was prepared of available NPSH versus location in the pump suction line. The HPCS system represents the worst case and is illustrated in Figure 211.213-1. At the worst point in the system, the available NPSH is 7.8+ feet which is above the 6 feet required to prevent flashing in the line. This calculation is conservative since the actual wetwell air space pressure at 220°F would be 2.5 psig (6 feet) not 0 psig as assumed per Regulatory Guide 1.1. This would provide an additional 6 feet of available NPSH at any point in the pump suction line.

HPCS

FIGURE 211.2D-1





*ASSUMING A PEAK SUPPRESSION POOL TEMPERATURE OF 220°F, THIS CALCULATION IS CONSERVATIVE SINCE THE WETWELL AIR SPACE PRESSURE WOULD NOT BE 0 PSIG AS INDICATED BUT WOULD ACTUALLY BE 2.5 PSIG (6 FEET). THIS WOULD INCREASE THE NPSH AVAILABLE AT EVERY POINT IN THE LINE.

Q. 211.018
(4.6.1)

Experience at some operating BWRs indicates that failures can occur in the collet fingers of the CRD mechanism. In order to resolve this problem, some BWR facilities under construction have installed a revised collet retainer design. However, you do not address this particular problem in your FSAR nor do you discuss its resolution. Accordingly, confirm whether the revised collet retainer design will be incorporated into the CRD mechanisms of the WNP-2 facility. Revise Table 1.3-8 of the FSAR as required.

Response:

WNP-2 does not have the revised collet retainer design. There have been no failures of collet fingers reported from the field. General Electric has demonstrated by testing and operating experience that the existing CRDs meet all safety and licensing requirements and are expected to give full life performances. However, as a result of examining operating drives, General Electric has discovered evidence of Intergranular Stress Corrosion Cracking (IGSCC) in some CRD drive components and has made disign improvements to preclude IGSCC in the future. The spare parts for CRD components purchased by the Supply System incorporate this revised design. Along with the other parts of the drive, the collet retainer tube, piston tube, and index tube will be routinely checked and changed out, if necessary, with the parts incorporating the revised design.

Q. 211.087
(15.1)

It is not evident to us that the drop of 100° Fahrenheit which you assume in the feedwater temperature results in a conservative evaluation of the cold feedwater transient when the recirculation flow is manually controlled. For example, a feedwater temperature drop of about 150° Fahrenheit occurred at an operating BWR in this country as a result of a single failure of an electrical component. The electrical equipment malfunction which was a breaktrip of a motor control center, caused a complete loss of all feedwater heating due to a total loss of extraction steam. Accordingly, submit: (1) a sufficiently detailed failure modes and effects analysis to demonstrate the conservatism of the 100° Fahrenheit feedwater temperature drop you assume considering the potential effects of any single electrical malfunction; or (2) calculations using a limiting feedwater temperature drop which clearly bounds current operating experience.

Further, reductions in feedwater temperature less than 100° Fahrenheit can occur which would represent more realistic (i.e., slower) changes in feedwater temperature with time. In particular, slow transients with the surface heat flux in equilibrium with the reactor power when the reactor scrams due to a feedwater temperature drop smaller than 100° Fahrenheit, could result in a larger change in the critical power ratio (CPR). Accordingly, evaluate the cold feedwater transient for all sequences of events that can cause a slow transient and demonstrate the conservatism of the values of the feedwater temperature drops, including the rate of change with respect to time, which you assume in your present transient analysis.

Response:

The GE feedwater heater system design specification to the A/E requires that the maximum temperature decrease which can be caused by bypassing feedwater heater(s) by any equipment single failure or operator error should be less than or equal to 100°F. This is the basis of the analysis. To verify proper design by the A/E, a review of the feedwater system was performed. A summary of the results of this review is given later in this response. In addition, the startup test program is designed to verify the results of this reviewer by verifying the most limiting single failures or operator errors in terms of impact on feedwater temperature drop. A startup test will then be performed which simulates such a failure or error to confirm plant response, MCPR transient behavior and feedwater temperature drop.

From the analysis with the assumed drop of 100°F in feedwater temperature, it shows that reactor scram due to high thermal power occurs during the transient. It is evident that transients resulting from feedwater temperature decreases greater than 100°F would also result in reactor scram due to high thermal power. Therefore, the transients are not more severe than the one shown in the FSAR. The conclusion that a greater than 100°F feedwater temperature reduction does not result in more severe transients is substantiated by an analysis performed on the LaSalle docket in the response to LaSalle Question 212.142. Due to similarity of design, the analysis is applicable to WNP-2. The analysis assumed a feedwater temperature drop of 150°F which bounds observed operating experience.

It should be pointed out that the peak valve of surface heat flux at the time of scram is determined only by the thermal power scram setpoint independent of the loss of feedwater heating rate. Therefore, reduction in feedwater temperature less than 100°F will not result in a larger ΔCPR than that reported in the FSAR.

The review of the plant feedwater heater cycle for WNP-2 was performed to determine the effects of the removal from service of combinations of feedwater heaters. Feedwater heaters were removed from service in accordance with the allowable feedwater system valving installed in the piping system (see Figure 211.087-1). The removal of feedwater heaters from service could be considered as planned or accidental, but the temperature drops in the feedwater were based on steady state (i.e., not transient) conditions. The following observations are pertinent:

a. Loss of part of, or all the low pressure heaters 1A, 1B, 1C, 2A, 2B, 2C, coincidently has little or no impact on the final feedwater temperature provided the remaining feedwater heaters are in service.

b. Loss of part of, or all the low pressure heaters 1A, 1B, 1C, 2A, 2B, 2C, 3A, 3B, 3C, 4A, 4B, 4C, coincidently has only a slight impact on the final feedwater temperature as long as all 5A, 5B, and 6A, 6B heaters are in service.

C. Loss of part of, or all low pressure heaters 3A, 3B, 4A, 4B, 4C, coincidently with one No. 5 and one No. 6 heater has a large temperature drop, however, calculations indicate this to be less than 100°F reduction in final feedwater temperature.

d. The effects of loss of or removal from service of both No. 6 heaters has a large temperature drop, but it is far less than 100°F.

e. The effects of loss of or removal from service of both No. 5 heaters with No. 6 heaters still in service has a small temperature drop since the No. 6 heaters perform with increased duty.

f. Removal from service of both No. 5 heaters, and one No. 6 heater or one No. 5 heater and both No. 6 heaters results in a temperature drop approaching but still less than 100°F, provided all other heaters are in service.

g. The investigation of the feedwater cycle indicated that large part of the feedwater heaters have to be removed from service before any substantial temperature drop results.

h. The removal of one of each of the three feedwater heaters No. 1, 2, 3, and 4 and one of each of the two feedwater heaters No. 5 and No. 6 coincidently (i.e., six feedwater heaters out of service, one from each stage extraction) results in a moderate (less than 50°F) temperature drop.

i. The removal from service of all the heaters of a turbine extraction stage has little effect on the final feedwater temperature expect in the case of loss of both No. 6 heaters.

j. The removal from service of all No. 3, 4, and 5 heaters with only No. 1, 2, and No. 6 heaters in service has a notable temperature depression drop however it is well below 100°F.

It should be noted that there are many non-mechauistic combinations of heaters which, if lost simultaneously, could result in a temperature drop greater than 100°F. However, no single equipment failure or operator error can produce these combinations. For information, these combinations are presented in Note 1.

Several transients were also reviewed to determine if it was possible to obtain a combination of feedwater heaters which resulted in a feedwater temperature drop greater than 100°F. No combination was found to exist.

a. Loss of offsite power - stops feedwater flow

b. Loss of instrument air - by-passes feedwater to the condenser

c. Loss of any motor-operated or air-operated extraction steam valve - loss of one heater

d. Loss of any motor-operated or air-operated valve in the condensate feedwater system - loss of feedwater heating train which would reduce feedwater flow or bypass of feedwater to the condenser

e. Loss of any motor-operated or air-operated valve in the heater drain system - negligible impact bacause heating might be lost in one feedwater heater

NOTE:

The following partial listing of coincident combinations of removal from service, or lost feedwater heater which will result in a feedwater temperature drop of 100°F or greater although no single equipment failure or operator error will produce these combinations.

1. 6A, 6B, 5A, 5B

2. 6A, 6B, 5A, 5B, 4A, 4B, 4C

3. 6A, 6B, 5A, 5B, 4A, 4B, 4C, 3A, 3B, 3C

4. 6A, 6B, 5A, 5B, 4A, 5B, 4C, 3A, 3B, 3C, 2A, 2B, 2C

5. All the feedwater heaters

6. 6A, 6B, (5A or 5B), 4A, 4B, 4C