TENNESSEE VALLEY AUTHORITY

CHATTANOOGA, TENNESSEE 37401

400 Chestnut Street Tower II

November 2, 1979

Director of Nuclear Reactor Regulation
Attention: Mr. L. S. Rubenstein, Acting Chief
Light Water Reactors Branch No. 4
Division of Project Management
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Dear Mr. Rubenstein:

In the Matter of the Application of	)	Docket Nos. 50-327
Tennessee Valley Authority	)	50-328

Enclosed is our response to the Containment Systems Branch questions on containment pressures transmitted by your letter to H. G. Parris dated September 27, 1979. This material will be incorporated into the Sequoyah Nuclear Plant Final Safety Analysis Report by Amendment 63 as Question 6.56B.

Very truly yours,

TENNESSEE VALLEY AUTHORITY

L M Mills

L. M. Mills, Manager
Nuclear Regulation and Safety

Enclosure

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ENCLOSURE

RESPONSE TO SEPTEMBER 27. 1979, LETTER
FROM L. S. RUBENSTEIN TO H. G. PARRIS

6.56B CONTAINMENT SYSTEMS BRANCH

In a letter dated September 10, 1979, the NRC was informed by Virginia Electric and Power Company that overpressurization of the containment at North Anna 3 and 4 could occur as a result of a main steam line break inside containment. This overpressurization resulted when auxiliary feedwater flow was included in the analysis. NRC is currently assessing the generic implications of this letter.

To assist us in determining if a similar circumstance could occur at your facility, you should take the following actions.

1) Review your original analysis of this event, and provide NRC with the assumptions used during this analysis. Particular emphasis should be placed on describing how auxiliary feedwater flow (AFF) was accounted for in your original analysis. (Reference to previously submitted information is acceptable if identified as to page number and date.) Any changes in your design which would impact the conclusions of your original analysis should be discussed. We are particularly concerned with design changes that could lead to an underestimation of the containment pressure following a MSLB inside containment.

2) Specifically, provide the following information for the analyses performed to determine the maximum containment pressure for a spectrum of postulated main steam line breaks for various reactor power levels:

   a. Specify the auxiliary feedwater flow rate that was used in your original containment pressurization analyses. Provide the basis for this assumed flow rate.

   b. Provide the auxiliary feedwater rated flow rate, the run out flow rate, and the pump head capacity curve of your current design.

   c. Provide schematic drawings to show the auxiliary feedwater system arrangement in your current design.

   d. Provide the time span over which it was assumed in your original analysis that AFF was added to the affected steam generator following a MSLB inside containment.

   e. Discuss the design provisions in the auxiliary feedwater system used to terminate the auxiliary feedwater flow to

1276 196

the affected steam generator. If operator action is required to perform this function, discuss the information that will be available to the operator to alert him of the need to isolate the auxiliary feedwater to the affected steam generator, the time when this information would become available, and the time it would take the operator to complete this action. If termination of auxiliary feedwater flow is dependent on automatic action, describe the basic operation of the auto-isolation system. Describe the failure modes of the system. Describe any annunciation devices associated with the system.

f. Provide the single active failure analyses which specifically identifies those safety grade systems and components relied upon to limit the mass and energy release and the containment pressure response.

RESPONSE 1

In the response to Q6.56, it has been shown that the Watts Bar Final Safety Analysis Report (FSAR) Section 6.2.1 may be referenced for the Sequoyah Nuclear Plant. In addition, response to Q6.56A provides the analysis for a spectrum of small breaks for the Sequoyah Nuclear Plant. (These analyses were added by Amendments 58 and 61 December 22, 1978, and May 25, 1979, respectively).

The assumptions made in the analysis (described in Section 6.2.1 of the Watts Bar FSAR) are:

a. Breaks were assumed to be double-ended ruptures occurring at the nozzle at one steam generator.

b. Blowdown from the broken steam line is assumed to be saturated steam.

c. Steam line and feedwater line isolation are completed at 10 seconds after the break occurs. The isolation signal is generated by a high steam flow-low steam line pressure signal from the Solid State Protection System. Maximum closure time for both the steam line and feedwater line isolation values is five seconds; thus a full five seconds is allowed for signal generation, processing and delay.

d. Plant power levels of 102 percent of nominal full load power, 30 percent of nominal full load power, and zero power were considered.

e. Full double-ended guillotine, 0.6 square foot, and 0.4 square foot ruptures were evaluated.

f. Failures of a main steam isolation valve, a diesel generator, a feedwater isolation valve, and auxiliary feedwater runout control were considered individually.

g. The auxiliary feedwater system is manually realigned by the operator after 10 minutes.

h. For the full double-ended ruptures, the main feedwater flow to the steam generator with the broken steam line was calculated based on an initial flow of 100 percent of nominal full power flow and a conservatively rapid steam generator depressurization. The peak value of this flow occurring just before isolation is 32.6 percent of nominal. For the smaller breaks, this same feedwater transient was conservatively assumed.

The auxiliary feedwater system will be actuated shortly after the occurrence of a steamline break. The mass addition to the faulted steam generator was from the auxiliary feedwater system may be conservatively determined by using the following assumptions.

a. The entire auxiliary feedwater system is assumed to be actuated at the time of the break and instantaneously pumping at its maximum capacity.

1276 198

b. The affected steam generator is assumed to be at atmospheric pressure.

c. The intact steam generators are assumed to be at the safety valve set pressure.

d. Flow to the affected steam generator is calculated from the auxiliary feedwater system head curves assumptions 2 and 3 above and the system line resistances. The effects of any flow limiting devices are considered.

e. The flow to the faulted steam generator from the auxiliary feedwater system is assumed to exist from the time of rupture to until realignment of the system is completed.

f. The failure of auxiliary feedwater runout control was considered separately, as a single failure. For this case, the auxiliary feedwater flow was determined using all the assumptions listed above and in addition failure of runout control on an auxiliary feedwater pump.

The auxiliary feedwater system on Sequoyah has not been changed in any way that would effect the conclusions of the original analysis.

RESPONSE 2

a. The analysis presented in the Watts Bar FSAR Section 6.2.1 and referenced for Sequoyah used the following auxiliary feedwater flow rates.

   (1) With runout protection operational a constant auxiliary feedwater flow rate of 1400 gpm to the faulted steam generator

   (2) Failure of runout protection was simulated by assuming a constant auxiliary feedwater flowrate of 2040 gpm to the faulted steam generator

The auxiliary feedwater flow rates calculated for Sequoyah using the assumptions outlined in the response to 1 above give values of 1100 gpm to the faulted steam generator with runout protection operating and 2065 with a single failure in the runout protection system. This difference of 25 gpm is insignificant.

The analysis of a spectrum of small steamline breaks provided in response to Q6.56A used an auxiliary feedwater flow rate of 1380 gpm. The small break cases have been reanalyzed using auxiliary feedwater runout flow in excess of 2000 gpm. The blowdown rates are different from those analyzed previously. However, since the peak containment temperature in ice condenser plants is primarily sensitive to the peak enthalpy in the blowdown, no change in peak temperature was observed. The transient temperature response was very similar. The response to Q6.56A will be amended with the new blowdown tables and figures.

b. The motor driven auxiliary feedwater (MDAF) pump is rated at 440 gpm and the turbine driven auxiliary feedwater (TDAF) pump is rated at 880 gpm. The pump head capacity curves are shown in Figures 10.4-20 and 10.4-21 of the Sequoyah FSAR. The MDAF pumps are equipped with pressure control valves which would limit the runout flow to 450 gpm. The TDAF pump speed is controlled by a flow signal to limit the flow to the steam generators to 880 gpm.

c. The auxiliary feedwater system arrangement is shown in Figure 10.4-19 of the FSAR.

d. The auxiliary feedwater system will be actuated shortly after the occurrence of a steamline break. In the analysis, the auxiliary feedwater flow to the faulted steam generator was assumed to exist from the time of the rupture until realignment of the system is complete. The auxiliary feedwater system is assumed to be manually realigned by the operator after 10 minutes. Therefore, the analysis assumes maximum auxiliary flow to a depressurized steam generator for a full 10 minutes. The actions taken by the operator to terminate auxiliary feedwater to the faulted steam generator are discussed in the response to e below.

e. Operator action is required to terminate the auxiliary feedwater flow to the affected steam generator. Information is available immediately upon initiation of accident.

   There will be approximately three minutes from initiation to termination of auxiliary feedwater flow to the affected steam generator. Information available to operator is given in EOI-2 (attached).

f. Several failures can be postulated which would impair the performance of various steamline break protection systems and therefore would change the net energy releases from a ruptured line. These are:

   (1) Main Steam Isolation Valve

   Failure of a main steam isolation valve increases the volume of steam piping which is not isolated from the break. When all valves operate, the piping volume capable of blowing down is located between the steam generator and the first isolation valve. If this valve fails, the volume between the break and the isolation valves in the other steam lines including safety and relief valve headers and other connecting lines will feed the break.

   (2) Failure of a diesel generator would result in the loss of one containment safeguards train resulting in minimum heat removal capability.

   (3) Failure of a feedwater isolation valve could only result in additional inventory in the feedwater line which would not be isolated from the steam generator. The mass in this volume can flush into the steam generator and exit through the break. Both the feedwater isolation valve and the feedwater regulating valve

close in no more than five seconds precluding any additional feedwater from being pumped into the steam generator. The additional line volume available to flush into the steam generator is that between the feedwater isolation valve and the feedwater regulating valve, including all headers and connecting lines.

(4) Failure of the auxiliary feedwater runout control equipment would result in higher auxiliary feedwater flows entering the steam generator before realignment of the auxiliary feed system.

The effect of these failures is to provide additional fluid which may be released to the containment by the break or reduce the heat removal capability of the containment safeguard systems.

In the analysis presented in Watts Bar FSAR Section 6.2.1.3.10 and referenced for the Sequoyah Nuclear Plant, the single failures listed above have been combined with various combinations of power level and break size to determine the worst steam line break cases.

Failure of the auxiliary feedwater isolation valve to close has not been considered. The maximum auxiliary feedwater flow that can be delivered to a faulted steam generator has been assumed in the analysis for 10 minutes, two cases being considered: (1) with runout protection operational, (2) with failure of runout protection. After 10 minutes, the operator takes action to isolate auxiliary feedwater to the broken steam generator. At that time, if the remote controlled auxiliary feedwater isolation valve fails to close, the operator can trip the two auxiliary feedwater pumps feeding the broken steam generator until this valve or another in the line is manually closed.

g. An analysis of a spectrum of steam line break at various power levels assuming several different single failures has been performed for McGuire and reported in FSAR Section 6.2.1.3.12. These analyses include cases assuming failure of auxiliary feedwater runout protection.

Consistent with the licensing basis for the McGuire Plant Operator action to realign auxiliary feedwater has been assumed only at 10 minutes.

Since the mass and energy release rates are considerably less than the RCS double ended breaks and their total integrated energy is not sufficient to cause ice bed meltout, the containment pressure transients generated for the RCS breaks will be more severe.

h. The mass and energy release data for the various cases analyzed is provided in Watts Bar FSAR Section 6.2.1.3.10 and referenced for application to Sequoyah Nuclear Plant in response to Q6.56. Additional cases are presented in Q6.56A. The assumptions made regarding the time at which active containment heat removal systems become effective and justificiation for the same are provided in response to Q6.56.

Sequoyah Nuclear Plant

EMERGENCY OPERATING INSTRUCTION

EOI-2

LOSS OF SECONDARY COOLANT

Units 1 and 2

Prepared By: C. T. Benton

Revised By: George Wilson

Submitted By: [signature] Supervisor

PORC Review: 7/16/79 Date

Approved By: [signature] for Superintendent

Date Approved: 7/16/79

DISTRIBUTION

1C	Plant Master File
	Superintendent
1U	Assistant Superintendent (Oper.)
	Assistant Superintendent (Maint.)
	Administrative Supervisor
	Maintenance Supervisor
	Assistant Maintenance Supervisor
	Results Supervisor
	Assistant Results Supv.
1C	Operations Supervisor
	Quality Assurance Supervisor
	Health Physicist
	Public Safety Services Supv.
	Chief Storekeeper
	Preop Test Program Coordinator
	Outage Director
	Chemical Engineer
	Radiochem Laboratory
	Instrument Shop
	Reactor Engineer
	Instrument Engineer
	Mechanical Engineer
	Staff Industrial Engineer
1C	Training Center Coordinator
	PSO - Chickamauga Engrg Unit - SNP
	Public Safety Services - SNP
1C	Shift Engineer's Office
1C	Unit Control Room
	QA&A Rep. - SNP
	Health Physics Laboratory
1U	Chief, Nuclear Generation Branch
1U	P Prod Central Office File
1U	Superintendent, WBNP
	Superintendent, BFNP
	Superintendent, BENP
1U	EN DES - MEB NEG
	Supv., NPHPS ROB, MS
	NRC-IE:II
	Power Security Officer, 604 PRB-C
	Nuclear Materials Coordinator
	Manager, OP-QA&A Staff
1U	P Prod Plant Eng. Branch

Rev. No.	Date	Revised Pages	Rev. No.	Date	Revised Pages
4	7/16/79	All			
					1276 202

POOR ORIGINAL

The last page of this instruction is Number 19.

LOSS OF SECONDARY COOLANT

A. Main Steam Line Break

B. Main Feedwater Line Break

MAIN STEAM LINE BREAK

I. SYMPTOMS

A. 1. Steam generator steam/feedflow mismatch alarm (38% of rated steam flow/ steam generator)

2. Steam generator loop 1 (2, 3, 4) high steamline flow alarm (if downstream of restrictor).

3. Steam generator loop pressure low alarm (650 psig)

4. Steam generator loop 1 (2, 3, 4) steamline ΔP high alarm (100 psi)

5. Steam generator 1 (2, 3, 4) level low alarm at 25 percent of span

6. Steam generator low low water level at 15% of span.

7. Steam line stop valves closed alarm.

8. Pressurizer pressure low alarm at 2210 psig

9. Pressurizer level low heaters off and letdown secured alarm at 17% of span.

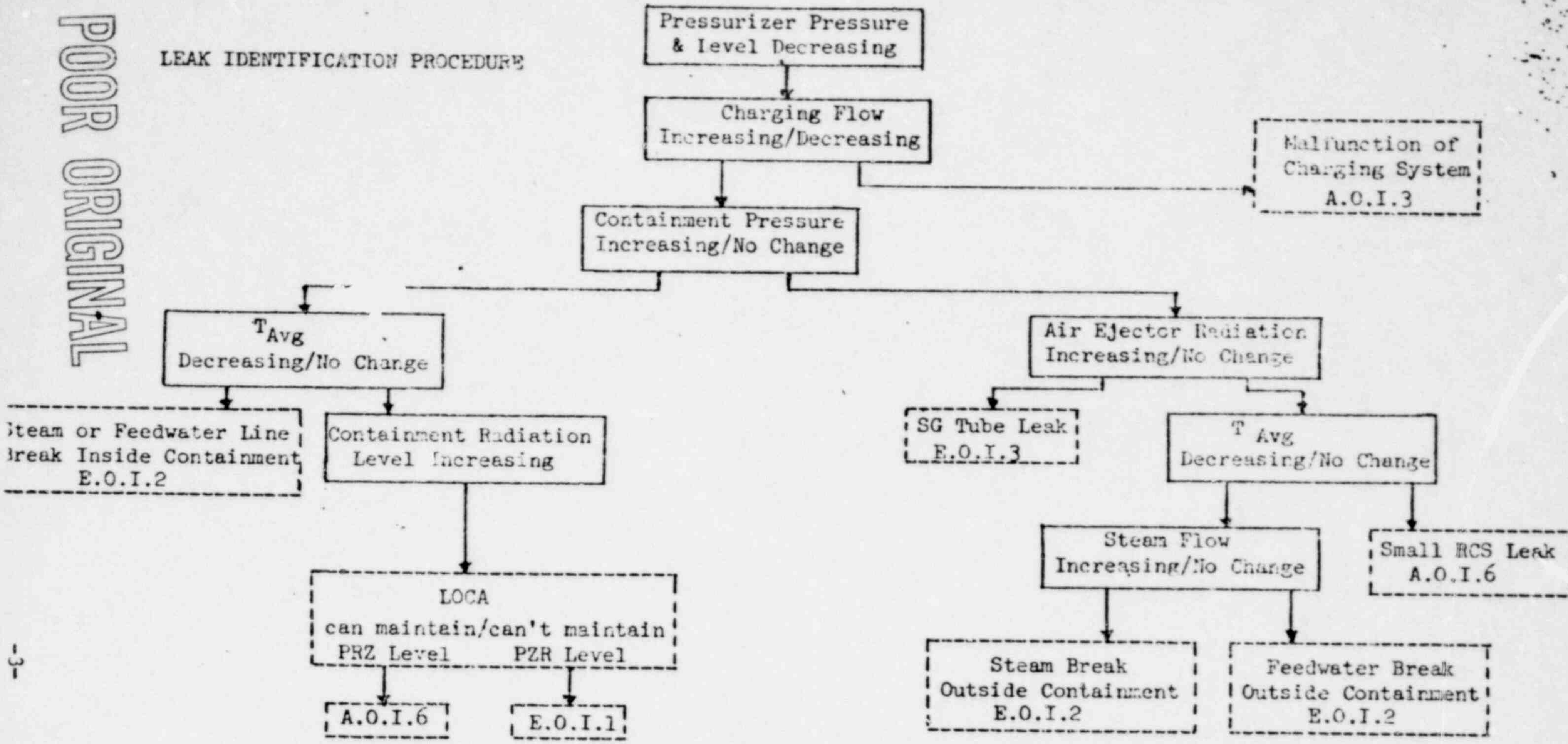
10. Reactor coolant loops low Tavg alarm at 554° F.

11. Containment pressure, temperature, and humidity increasing with no activity increase if break is inside containment.

1276 204

TA II.

LEAK IDENTIFICATION PROCEDURE



Main Steam Line Break

EOI-2A - Unit 1 & 2
Page 2 of 7
Rev. 4

1276 205

TABLE II

SYMPTOMS FOR LOCA, STEAM GENERATOR TUBE RUPTURE, STEAMBREAK, or FEEDWATER LINE BREAK INSIDE CONTAINMENT

SYMPTOM	SMALL LOCA	LARGE LOCA	STEAM GENERATOR TUBE RUPTURE	STEAMBREAK BEFORE FLOW RESTRICTOR	STEAMBREAK AFTER FLOW RESTRICTOR	FEEDWATER BREAK
1. T avg	→	→	→	↘	↘	4 ↘
2. Reactor Coolant System Pressure	↘	↓	↘	↘	↘	4 ↘
3. Pressurizer Level	2 ↘	↓	↘	↘	↘	4 ↘
4. Volume Control Tank Level	↘	↓	↘	↘	↘	4 ↘
5. Containment, Pressure, Temperature, and Humidity	↗	↑	→	↗	↗	4 ↗
6. Containment Airborne Radiation	↗	↑	→	→	→	→
7. Steam Flow	→	→	→	1 ↓ 3 ↗	1 ↑ 3 ↗	1 ↘ 3 ↗
8. Steam Pressure	→	→	1 ↗ 3 →	1 ↓ 3 ↘	1 ↘ 3 ↘	1 ↘ 3 ↘
9. Feedwater Flow	→	→	1 ↘ 3 →	1 ↗ 3 ↗	1 ↗ 3 ↗	1 ↑ 3 ↘
10. Steam Generator Level	→	→	1 ↗ 3 →	1 ↘ 3 ↘	1 ↘ 3 ↘	1 ↘ 3 ↘
11. Air Ejector Radiation	→	→	↑	→	→	→
12. S.G. Blowdown Radiation	→	→	1 ↑ 3 →	→	→	→
13. Charging Flow	↗	↑	↑	↗	↗	↗

Main Steam Line Break

1276 206

2 If loss of coolant is pressurizer relief or safety stuck open, this may not drop initially

1 - Affected Steam Generator
3 - Other Steam Generators

4. These parameters may be opposite under certain conditions & indicative

II. AUTOMATIC ACTIONS

A. Reactor trip/safety injection may be by any of the following:

1. Low pressurizer pressure.

2. High differential pressure signals between steam lines.

3. High steam line flow in two main steam lines (one-out-of-two per line) in coincidence with either low-low reactor coolant system average temperature or low steam line pressure in any two lines.

4. Two-out-of-three high containment pressure.

B. Steamline isolation may be initiated by:

1. High steam flow in two main steam lines in coincidence with either low-low reactor coolant system average temperature or low steam line pressure in any two lines.

2. High-high containment pressure.

C. Phase B isolation and containment spray on 2/4 high-high containment.

D. Feedwater isolation and automatic control of aux. feedwater valves on accident signal.

III. IMMEDIATE OPERATOR ACTION

CAUTION: Voiding in RCS could take place. Monitor RCS pressure and temperature closely. To enhance core cooling do not remove HPI pumps (centrifugal charging pumps) unless continued operation could overpressurize RCS. Guidelines for removing HPI are in Subsequent Actions.

CAUTION: If RCS pressure falls below 1765 psig and SI has not automatically initiated, manually initiate SI.

A. Verify turbine trip-reactor trip

1. All rods in - Emergency borate 100 ppm for each rod not fully inserted.

2. Turbine steam stop valves closed.

3. Auxiliary feedwater pumps running and flow established to steam generators.

4. Determine pressurizer pressure and level.

5. Generator breakers open and 6.9-kV unit station service transferred.

6. Steam generator feedwater regulator, regulator bypass valves, and main isolation valves closed.

1276 207

III. IMMEDIATE OPERATOR ACTION (Cont.)

B. Verify safety injection and containment isolation actuated.

1. Phase A: Panel 6C - Dark; Panel 6D - Dark; Panel 6E (except as outlined) - Light; Panel 6F (except as outlined) - Light; Panel 6G - Dark; Panel 6H - Dark. Verify proper flow through BIT tank for existing RCS pressure. When RCS pressure falls below 1500 psig, verify SIS pump flow to cold legs.

2. Phase B containment isolation and containment spray actuated: Panel 6C - Dark; Panel 6D - Dark, Panel 6E - Light; Panel 6F - Light, Panel 6G - Dark; Panel 6H - Dark.

3. Main steam line isolation valves will be closed if all the alarms in either a or b below are in.

a. (1) Containment Hi Hi Pressure Steam Line Isolation

b. (1) Steam generator 2/4 loops hi steam flow and

(2) Steam generator 2/4 loops pressure low or

(3) Rx coolant 2/4 loops lo-lo Tavg

4. Trip two (opposite loops) reactor coolant pumps if Phase "B" isolation occurs or if level is lost in pressurizer and continue to operate the other two until motor bearing temperature exceeds 225°F, pump bearing temperature exceeds 250°F, or motor winding temperature exceeds 275°F or pump amp and/or flow motor indicates loss of forced cooling. If all pumps are stopped, refer to Appendix 2A for guidelines

CAUTION: Automatic controls are not to be placed in manual unless it is apparent the automatic action has failed. If a control is placed in manual, it is to be frequently checked for proper operation.

IV. SUBSEQUENT OPERATOR ACTION

A. To prevent overpressurization of the RCS following a main steam line break, operate the HPI (cent. charging pumps) for at least 20 minutes if possible but do not allow RCS overpressurization to occur. Continuously monitor the RCS pressure and hot leg (highest) temperature. All the following conditions should be met in determining when to stop HPI:

a. SG secondary system providing primary coolant (by forced flow when RCP's are running or natural circulation when RCP's are off.)

b. Pressurizer level $\geq$ 50% and increasing.

1276 208

IV. SUBSEQUENT OPERATOR ACTION (Cont.)

c. RCS pressure ≥ the 50°F subcooled temperature for the existing hot leg temperature, and pressure is rising. When these conditions are met, reset SI, secure ECCS or leave SI pumps running as backup cooling.

NOTE: When pressurizer level is restored, re-establish PZR heaters if offsite power is available.

Prepare to open the PRZ power operated relief valves if the pressure-temperature relationship approaches the limit of the "RCS Pressure-Temperature Limitations Curve." (Figure A.11.1 of Curve Book, TI-28).

CAUTION: Use only PAM identified instrumentation for monitoring and evaluating plant conditions.

B. The following instruments are designated as post accident monitors. Actions should be based on these qualified instruments.

1. Reactor Coolant System Pressure PI-68-68A, 66.
2. Pressurizer Water Level LI-68-320, 335A
3. Reactor Coolant System Temperature TR-68-1, 60
4. Containment Pressure PI-30-44, 45.
5. Steam Generator Water Level (narrow range) LI-3-39, 52, 94, 197
6. Steam Generator Water Level (wide range) LR-3-43, 98
7. Steam Line Pressure PI-1-2A, 2B, 9A, 9B, 20A, 20B, 27A, 27B
8. Refueling Water Storage Tank Level LI-63-50, 51,

C. Identify the location of the break by observing the following:

1. Steam Generator Level and Pressure Lower than others and falling.
2. High steam flow, if break is downstream of restrictor; low if upstream.
3. Containment pressure - increasing if inside containment.
4. Lower Tavg in affected loop.
5. Table II.1 and II.2 may be used in break location identification.

D. Isolate affected steam generator and align systems as follows:

1. Stop reactor coolant pump on affected loop. (Not applicable if break is downstream of steamline isolation valve).
2. Close the main steam isolation valves on the affected loop if not already closed.
3. Close auxiliary feedwater to affected steam generator. (not applicable if break is downstream of steamline isolation valve).

IV. SUBSEQUENT OPERATOR ACTION (Cont.)

4. Place additional control rod drive and lower containment cooling fans in service if break is inside containment.

5. Transfer NR-45 to 1 SR and 1 IR monitor.

6. Reset safety injection signal after 1 minute if not already reset.

7. As pressurizer water level rises, ensure primary pressure is greater than 200 psi above corresponding saturation pressure as indicated on hot leg RTD's, then stop as many injection pumps as necessary to maintain pressurizer water level $\geq$ 50%. Reestablish pressurizer heaters to maintain a steam bubble in the pressurizer if not already accomplished.

   CAUTION: Allow centrifugal charging pumps to discharge through boron injection tank a minimum of three minutes; this ensures addition of 300 ppm boron.

8. If all RCP's were taken off, reset phase B isolation (if it was initiated, to re-establish RCP cooling and restart loop 1 and/or 2 RCP's.

9. Stop other energized safeguard equipment not needed.

   CAUTION: Ensure conditions are stable and causes known before stopping any engineered safety equipment.

10. Regulate feedwater flow to the unaffected steam generators to establish normal level. Regulate feedwater to all S/G if break is downstream of main steam isolation valves.

11. Implement emergency plan as required.

    CAUTION: Should the RCS temperature decrease below the NDTT for the reactor vessel, do not deliberately increase system pressure.

E. Dump steam as required to remove residual heat and stabilize the reactor coolant temperature. (Use power relief valves).

   NOTE: A relatively constant steam pressure in the unaffected steam generators while dumping steam at a constant rate indicates the reactor coolant temperature has stabilized. Monitor reactor coolant temperature (wide range) and incore thermocouples, to establish that coolant temperature has stabilized.

F. When reactor coolant temperature has stabilized, sample reactor coolant to determine boron concentration and borate the reactor coolant as necessary for a cold shutdown boron concentration.

1276 210

V. RECOVERY

A. Establish the reactor systems necessary for a controlled cooldown to the cold condition.

1. Establish charging and letdown per SOI-62.1.

2. If reactor coolant pump(s) are not already operating, place No. 1 or No. 2 reactor coolant pump (non-affected loop) in service per SOI-68.2 for sprays.

3. Set CVCS makeup control for proper blend concentration.

B. Cooldown in accordance with procedure GOI-3, "Plant Shutdown from Minimum Load to Cold Condition."

VI. DISCUSSION

This emergency is a break in a main steam line and will result in a reduction in reactor coolant temperature and pressure at a rate which is dependent upon the size and location of the break.

The steam release arising from a break of a main steam pipe would result in an initial increase in steam flow which decreases during the accident as the steam pressure falls. In the presence of a negative moderator temperature coefficient, the cooldown results in a reduction of core shutdown margin. A return to power following a steam pipe rupture is a potential problem mainly because of a high power peaking factor which exists if the most reactive RCCA is stuck full out. The reactor is ultimately shut down by the boron in the boron injection tank (BIT) being presented to the RCS during the safety injection phase.

Since the initial steam generator water inventory is greatest at no load, the magnitude and duration of the RCS cooldown are less for steam line breaks occurring at power. Under worse condition (failure of check valve in broken line) containment pressure may go to 6.4 psig.

The main feedwater is terminated during safety injection phase to minimize cooldown.

The main steam isolation valves are closed to terminate blowdown if leak is downstream of steam line check valves and allows only one steam generator to blowdown.