GULF STATES UTILITIES COMPANY
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December 12, 1983
RBG-16,543
File Code G9.5, G9.8.6.1

Mr. Harold R. Denton, Director
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Mr. Denton:

River Bend Station Units 1 & 2
Docket Nos. 50-458/50-459

Enclosed for your review are Gulf States Utilities Company's (GSU) responses to Draft Safety Evaluation Report (DSER) open items identified by the Nuclear Regulatory Commission's (NRC) Reactor Systems Branch (RSB). In addition, the Licensing Review Group-II (LRG) positions 1-13-RSB and TMI Action Plan Requirements requested in a NRC letter to GSU dated April 21, 1983 are discussed herein. Attachment 1 is a summary listing of the items discussed in Attachment 2. Attachment 2 provides the response and reference material for each item. Where indicated, these responses will be provided in a future amendment to the FSAR.

Sincerely,

J. E. Booker

J. E. Booker
Manager-Engineering
Nuclear Fuels & Licensing
River Bend Nuclear Group

JEB/RJK/ap

Attachments-40 copies

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Attachment 1

RSB OPEN ITEMS

	DSER SECTION	RELATED QUESTION	SUBJECT	FSAR CHANGES
1.	5.2.2 pg.5-5	Q#440.14	SRV improvements	Amendment 9
2.	5.2.2 pg.5-6	Q#440.10	ADS air supply	Amendment 3 & Enclosure 1
3.	5.4.6 pg.5-33	Q#440.19	RCIC hi temp trip setpoints	Enclosure 2
4.	5.4.7 pg.5-37	Q#440.29	RHR MOV delta-p interlock	Amendment 7
5.	5.4.7 pg.5-38	Q#440.32 Q#440.58	Verify flow capacity for alternate shutdown path (ASDP)	Amendment 3 & Enclosure 4
6.	5.4.7 pg.5-38	Q#440.32 Q#440.58	RHR pump head-flow rqmts for ASDP	Amendment 3 & Enclosure 4
7.	5.4.7 pg.5-39	Q#440.28 Q#440.34 Q#440.57	RHR NPSH	Enclosure 5
8.	6.3.3 pg.6-52	Q#440.28 Q#440.34 Q#440.57	ECCS pumps NPSH	Amendments 9 & 10 & Enclosure 5
9.	6.3.3 pg.6-53	Q#440.29 Q#440.35	Lo/hi pressure interface interlocks	Amendment 7 & Enclosure 3
10.	6.3.3 pg.6-54	Q#440.36	HPCS L8 & hi drywell press. interlock	Enclosure 17
11.	6.3.3 pg.6-57	Q#440.40	Plant specific ECCS analysis	-------
12.	6.3.3 pg.6-57	Q#440.37 Q#440.42	No operator action for 20 minutes	Enclosure 6
13.	6.3.3 pg.6-58	Q#440.43 Q#440.53	LOCA & recirc FCV failure	Enclosure 7
14.	6.3.4.2 pg.6-59		ECCS surveillance	-------
15.	15.1 pg.15-6	Q#440.48	Simulated Thermal Power Trip	Amendment 7
16.	15.1	Q#440.50	EOC operations with partial feedwater	Amendment 5 &

Attachment 1 (cont'd)

	DSER SECTION	RELATED QUESTION	SUBJECT	FSAR CHANGES
	pg.15-7	Q#440.59	heating	Enclosure 8
17.	15.1 pg.15-8	Q#440.51	Recategorize generator load reduction and turbine trip without bypass	Amendment 7
18.	15.1 pg.15-8	Q#440.53	Level 8 & turbine bypass in technical specification	Enclosure 9
19.	15.2 pg.15-8	Q#440.53 Q#440.54	Non-Safety Related equipment credit in analyses	Amendment 7 & Enclosure 9
20.	15.6.1 pg.15-39	Q#440.45	Transient analysis with single failure	Enclosure 10
21.		Q#440.47	Failure of RHR shutdown cooling mode	Enclosure 11
22.		Q#440.49	SRV failure shutdown criteria	Enclosure 12
23.		Q#440.55	ATWS RPT & operator training	Amendment 7
24.		Q#440.38	Steam line breaks inside and outside containment	Enclosure 13
25.		Q#440.41	Operator action precluding over pressurization	Enclosure 14
26.		Q#440.10 Q#440.16 Q#440.17 Q#440.18 Q#440.27 Q#440.32 Q#440.44 Q#440.56 Q#440.58	TMI items	Enclosure 15
27.			LRG-II 1-RSB Requirement for Automatic Restart of HPCS after manual termination	---------

Attachment 1 (cont'd)

DSER SECTION	RELATED QUESTION	SUBJECT	FSAR CHANGES
		LRG-II 2-RSB(a) Design Adequacy of the RCIC System Providing Automatic Restart	Enclosure 15
		LRG-II 2-RSB(b) Design Adequacy of the RCIC System Preventing Inadvertent RCIC System Isolation	Enclosure 15
		LRG-II 2-RSB(c) See 4-ASB/Design Adequacy of the RCIC System Description of Pump Room Cooling	Enclosure 2
		LRG-II 2-RSB(d) Design Adequacy of RCIC System Water Hammer Protection	Amendment 3 Q440.26
		LRG-II 3-RSB Safety-Relief Valve Surveillance Program	Amendment 3 Q440.15
		LRG-II 4-RSB Operator Action Required 10-20 Minutes Following a LOCA	Enclosure 6, Enclosure 13, & Enclosure 14
		LRG-II 5-RSB Control of Post-LOCA Leakage to Protect ECCS and Pre-serve Suppression Pool Level	Enclosure 16
		LRG-II 6-RSB Applicability of the Liquid-Flow-Through-SRV Tests Performed in Response to TMI Action Item II.D.1	Enclosure 16
		LRG-II 7-RSB Provisions to Preclude Vortex Formation (Unresolved Safety Issue A-43)	Enclosure 5
		LRG-II 8-RSB Assurance for Long Term Operability of the Automatic Depressurization System (ADS)	Amendment 3 Q440.10 & Enclosure 1

Attachment 1 (cont'd)

DSER SECTION	RELATED QUESTION	SUBJECT	FSAR CHANGES
		LRG-II 9-RSB Long Term Operability of Deep Draft Pumps	Enclosure 16
		LRG-II 10-RSB LOCA Analysis with Recirculation Flow Control Valve Closure	Enclosure 7
		LRG-II 11-RSB Use of Nonsafety Grade Equipment in Shaft Seizure Event	Amendment 7 Enclosure 9 440.53 440.54
		LRG-II 12-RSB Proper Classification of Transients	Amendment 7 Q440.51
		LRG-II 13-RSB Removal of High Pressure Interlock on HPCS Circuitry	Enclosure 17

ATTACHMENT 2
RSB

1. DSER, page 5-5 - SRV Improvements

Response

This item is addressed in the response to FSAR Question 440.14, Chapter 5, which was submitted to the NRC in FSAR Amendment 9.

2. DSER, page 5-6 - ADS Air Supply
LRG-II issue 8-RSB
TMI Action Plan Item II.I.3.28

Response

This item is addressed in the response to FSAR Question 440.10, Chapter 5, which was submitted to the NRC in FSAR Amendment 3. Supplemental information to FSAR Section 5.2.2.4.1 is provided in Enclosure 1.

3. DSER, page 5-33 - RCIC High Temperature Trip Setpoints
LRG-II issues 4-ASB and 2-RSB (c)

Response

The revised response to FSAR Question 440.19 and the endorsement of LRG-II positions 4-ASB and 2-RSB(c) are provided in Enclosure 2. The enclosed discussion of setpoint determinations to prevent inadvertent isolations of the RHR and RCIC systems and their high area temperature trip settings will be included in a future FSAR amendment.

4. DSER, page 5-37 - RHR MOV. Delta - P Interlock
LRG-II Issue 2-ICSB

Response

This item is addressed in the response to FSAR Question 440.29, Chapter 5, which was submitted to the NRC in FSAR Amendment 7.

5. DSER, page 5-38 - Verify Flow Capacity for Alternate Shutdown Path

and

6. DSER, page 5-38 - RHR Pump Head-Flow Requirements for Alternate Shutdown Path

Response

The flow capacity of the safety/relief valves is sufficient to pass water for piping and valves required in the alternate shutdown path. Pressure drop calculations were performed to verify the RHR pumps could provide sufficient flow for the alternate shutdown path. Preoperational testing will be performed on the components of the alternate shutdown system. Additional

information is provided in Enclosure 4 for FSAR Question 440.58. A response to FSAR Question 440.32 was provided in Amendment 3, Chapter 5. This information will be incorporated into the FSAR in a future amendment as the response to Question 440.58.

7. DSER, page 5-39 - RHR Net Positive Suction Head
   LRG-II Issue 7-RSB

and

8. DSER, page 6-52 - ECCS Pumps Net Positive Suction Head

<u>Response</u>

This item is addressed in the response to FSAR Questions 440.28 and 440.34 which were provided in Amendments 9 and 10, respectively. The response to FSAR Question 440.57 and the endorsement of LRG-II issue 7-RSB is provided in Enclosure 5.

9. DSER, page 6-53 - Low/High Pressure Interface Interlocks; 2-ICSB

<u>Response</u>

The response to this item is provided in the response to Questions 440.29 (Amendment 7) and the revised response to Question 440.35 (Enclosure 3).

10. DSER, page 6-54 - HPCS Level 8 and High Drywell Pressure
    LRG-II issue 13-RSB

<u>Response</u>

This item is addressed in the revised response to FSAR Question 440.36 provided in Enclosure 17. LRG-II position 13-RSB is endorsed therein.

11. DSER, page 6-57 - Plant Specific ECCS Analysis

<u>Response</u>

This item is scheduled in the response to FSAR Question 440.40, Chapter 6. The unique ECCS LOCA analysis will be submitted at least 6 months before fuel load.

12. DSER, page 6-57 - No Operator Action for 20 Minutes
    4-RSB and TMI Action Item II.K.3.18

<u>Response</u>

GSU is modifying its automatic depressurization trip system with a bypass timer on the drywell pressure signal which will provide an automatic backup to operator action to ensure adequate core cooling. This item is discussed in the response to FSAR Questions 440.42 and 440.37 (Enclosure 6).

13. DSER, page 6-58 - LOCA & Recirculation Flow Control Valve Failure LRG-II Issue 10-RSB

Response

The response to FSAR Question 440.43 (Enclosure 7) indicates that the inadvertent closure of the recirculation system line suction valve, as a single failure in the RBS LOCA analysis, is bounded by the flow control valve failure analysis. This analysis is completed in the LRG-II position 10-RSB.

14. DSER, page 6-59 - ECCS Surveillance

Response

The RBS Technical Specifications corresponding to STS Section 4.5-1, will specify surveillance intervals for testing the subsystems comprising the ECCS approximately every 92 days to show that specified flow rates are attained. Also, approximately every 18 months a test will be performed in which all subsystems are actuated through the emergency operating sequence.

15. DSER, page 15-6 - Simulated Thermal Power Trip

Response

This item is addressed in the response to FSAR Question 440.48, Chapter 15, which was submitted in FSAR Amendment 7.

16. DSER, page 15-7 - End of Cycle Operations with Partial Feedwater Heating

Response

This item is addressed in the response to FSAR Question 440.50, Chapter 15, which was submitted in FSAR Amendment 5. The requested analysis will be provided as discussed in the enclosed response to FSAR Question 440.59 (Enclosure 8). This response will be provided in a future amendment to the FSAR.

17. DSER, page 15-8 - Recategorize Generator Load Reduction and Turbine Trip Without Bypass LRG-II Issue 12-RSB

Response

This item is addressed in the response to FSAR Question 440.51, Chapter 15, which was submitted in FSAR Amendment 7.

Attachment 2 (cont'd)

18. DSER, page 15-8 - Level 8 & Turbine Bypass in
    Technical Specifications
    LRG-II Issue 11-RSB

    Response

    The RBS Technical Specifications will identify equipment availability, set points, and surveilence testing. A revised response to FSAR Question 440.53 is provided in Enclosure 9. This information will be provided in a future amendment to the FSAR.

19. DSER, page 15-8 - Non-Safety Related Equipment
    Credit in Analyses
    LRG-II Issue 11-RSB

    Response

    A revised response to FSAR Question 440.53 is provided in Enclosure 9. The response to Question 440.54, submitted in Amendment 7, addresses this request in part. The information provided will be included in a future amendment to the FSAR.

20. DSER, page 15-39 - Transient Analysis with Single Failure

    Response

    A revised response to FSAR Question 440.45 is provided in Enclosure 10. This information will be provided in a future amendment to the FSAR.

21. A revised response to FSAR Question 440.47, "Failure of RHR Shutdown Cooling Mode" is provided in new FSAR Section 15.2.9 (Enclosure 11). This new section will be provided in a future amendment to the FSAR.

22. A revised response to FSAR Question 440.49, "Inadvertent opening of a SRV", is provided in Enclosure 12. This response will be included in a future amendment to the FSAR.

23. A response to FSAR Question 440.55, "ATWS", was provided to the NRC in FSAR Amendment 7, Chapter 15.

24. A revised response to FSAR Question 440.38, "Steam Line Breaks Inside and Outside Containment", is provided in Enclosure 13. While core uncovery may take place, the analyses requires no operator action to maintain peak clad temperatures less than 2200°F. This response will be provided in a future amendment to the FSAR.

25. A revised response to FSAR Question 440.41, "Operator Action Precluding Over Pressurization", is provided in Enclosure 14. This information will be included in a future amendment of the FSAR.

Attachment 2 (cont'd)

26. Responses to FSAR questions concerning specific TMI Action Item requirements are referenced in the table below. These responses will be included in FSAR Appendix 1A in a future amendment.

ITEM	RESPONSE
Q440.27, Chapter 5	
II.K.1.22	Amendment 7
II.K.3.13	Enclosure 15
II.K.3.15	Enclosure 15
Q440.44, Chapter 6	
II.K.1.5	Amendment 7
II.K.1.10	Amendment 7
II.K.1.22	Amendment 7
II.K.3.16	Amendment 7
II.K.3.17	Amendment 7
II.K.3.18	Enclosure 6
II.K.3.21	Amendment 7
II.K.3.25	Enclosure 15
II.K.3.30	Amendment 7
II.K.3.31	Amendment 7
II.K.3.45	Amendment 7
Q440.56, Chapter 15	
II.K.3.44	Amendment 7
Q's440.32, 440.58, 440.16, Chapter 5	
II.D.1	Amendment 3
Q440.10, Chapter 5	
II.K.3.28	Enclosure 1
Q440.17, Chapter 5	
II.D.3	Amendment 7
Q440.18, Chapter 5	
II.B.1	Amendment 3

Attachment 2 (cont'd)

27. The endorsement to LRG-II positions 1-RSB through 13-RSB is provided below. The discussion of these items is provided in the enclosures.

ITEM	TITLE	ENDORSED	FSAR DISCUSSED
1-RSB	Requirement for Automatic Restart of HPCS after Manual Termination	Yes	Appendix 1, II.K.3.21
2-RSB(a)	Design Adequacy of the RCIC System Providing Automatic Restart	Yes	Appendix 1A II.K.3.13
2-RSB(b)	Design Adequacy of the RCIC System Preventing Inadvertent RCIC System Isolation	Yes	Appendix 1A II.K.3.15
2-RSB(c)	See 4-ASB/Design Adequacy of the RCIC System Description of Pump Room Cooling	Yes	Q440.19 Ch. 15 Q&R Appendix 1A II.K.3.24
2-RSB(d)	Design Adequacy of RCIC System Water Hammer Protection	Yes	5.4.6.1
3-RSB	Safety-Relief Valve Surveillance Program	Yes	5.2.2.11
4-RSB	Operator Action Required 10-20 Minutes Following a LOCA	Yes	Appendix 1A II.K.3.18
5-RSB	Control of Post-LOCA Leakage to Protect ECCS and Preserve Suppression Pool Level	No	6.3.1.1.3
6-RSB	Applicability of the Liquid-Flow-Through-SRV Tests Performed in Response to TMI Action Item II.D.1	Yes	Appendix 1A II.D.1 5.4.7.1.5
7-RSB	Provisions to Preclude Vortex Formation (Unresolved Safety Issue A-43)	Yes	6.3.2.2
8-RSB	Assurance for Long Term Operability of the Automatic Depressurization System (ADS)	Yes	5.2.2.4.1
9-RSB	Long Term Operability of Deep Draft Pumps	Yes	9.2.7.4
10-RSB	LOCA Analysis with Recirculation Flow Control Valve Closure	Yes	Q440.43 Ch. 6 Q&R

Attachment 2 (cont'd)

ITEM	TITLE	ENDORSED	FSAR DISCUSSED
11-RSB	Use of Nonsafety Grade Equipment in Shaft Seizure Event	Yes	Q440.53 Ch. 15 Q&R
12-RSB	Proper Classification of Transients	Yes	Q440.51 Ch. 15 Q&R
13-RSB	Removal of High Pressure Interlock on HPCS Circuitry	Yes	6.3.2.2.1 7.3.1.1.1.1

4. Duration of operability is 2 days at 200°F and 20 psig, following which the valves remain fully open or closed for 97 days, provided air and power supply is available. No power/air supply is required to keep the valve closed.

The ADS utilizes selected SRVs for depressurization of the reactor as described in Section 6.3. Each of the SRVs is equipped with an air accumulator and check valve arrangement. The accumulators on the SRVs utilized for automatic depressurization assure that the valves can be held open following failure of the air supply to the accumulators. The accumulator capacity is sufficient for each ADS valve to provide two actuations against 70 percent of the maximum drywell design pressure.

The acccumulators are designed to provide two ADS actuations at 70 percent of drywell design pressure, which is equivalent to 4 to 5 actuations at atmospheric pressure. The ADS valves are designed to operate at 70 percent of drywell design pressure because that is the maximum pressure for which rapid reactor depressurization through the ADS valves is required. The greater drywell design pressures are associated only with the short duration primary system blowdown in the drywell immediately following a large pipe rupture for which ADS operation is not required. For large breaks which result in higher drywell pressure, sufficient 3
reactor depressurization occurs due to the break to preclude the need for ADS. One ADS actuation at 70 percent of drywell design pressure is sufficient to depressurize the reactor and allow inventory makeup by the low pressure ECC systems. However, for conservatism, the accumulators are sized to allow 2 actuations at 70 percent of drywell design pressure.

The River Bend Station design utilizes 60-gal accumulators and an ~~safety grade~~ air charging system ~~(Penetration Valve Leakage Control System)~~. The air supply system includes two ASME III Division I, Class 2 air compressors[1] which feed two separate charging systems for the accumulators. Both[2] compressors are powered from the preferred ac power supply systems and can be powered by on-site power. Each charging system consists of an air dryer and associated piping and valves necessary to provide air to each of the two divisional sets of accumulators. Each charging system has physical separation in order to protect them from postulated pipe breaks.

Only two of the ADS valves need to function to meet short-term demands and the functional operability of only

[1] and two non-nuclear safety compressors

[2] ASME III

one ADS valve can fulfill longer term needs. ~~Each accumulator is instrumented to provide the reactor operator with indication of an air supply problem~~.

3 The air supply to the ADS valves has been designed such that the failure of any one componenet does not result in the loss of air supply to more than one nuclear safety-related division of ADS valves. The loss of air supply to one division of ADS valves does not prevent the safe shutdown of the unit.

~~SRV and ADS pneumatic accumulators are supplied with air from the penetration valve leakage control system (PVLCS)~~. INSERT A
2 ~~The air from the PVLCS is dried to a dewpoint of 0°F at 100 psig and filtered to a maximum particle size of 3 microns. Refer to Section 9.3.6 for a description of the PVLCS~~.

Each SRV discharges steam through a discharge line to a point below the minimum water level in the suppression pool. The SRV discharge lines are classified as Safety Class 3 and Seismic Category I. SRV discharge line piping from the SRV to the suppression pool consists of two parts. The first is attached at one end to the SRV and attached at its other end to a pipe anchor. The main steam piping, including the SRV discharge piping up to and including the first anchor, is analyzed as a complete system. Diameter, length, and
1 routing of the SRV piping are given in Appendix 6A, Table A.6A.4-1 and Fig. A.6A.10-1 and A.6A.10-2.

The second part of the SRV discharge piping extends from the anchor to the suppression pool. Because of the upstream anchor on this part of the line, it is physically decoupled from the main steam header and is therefore analyzed as a separate piping system.

The effect of the alternate shutdown cooling mode on SRV discharge piping has been considered. The resultant load
7 distribution is within the design capacity of the spring hangers and other support structures.

As a part of the preoperational and startup testing of the main steam lines, movement of the SRV discharge lines will be monitored.

The SRV discharge piping is designed to limit valve outlet pressure to 40 percent of maximum valve inlet pressure with the valve wide open. Water in the line more than a few feet above suppression pool water level would cause excessive pressure at the valve discharge when the valve is again

During normal plant operation, SRV and ADS accumulators are supplied with air from the non-nuclear safety (NNS) service air system air compressors as discussed in Section 9.3.1. These compressors provide 17 SCFM at 175 psig. Post-LOCA air requirements are supplied from the Penetration Valve Leakage Control System (PVLCS). Refer to section 9.3.6 for a description of the PVLCS.

Air from either source is dried to a dewpoint of -40°F at 140 psig and filtered to a maximum particle size of 1 micron. The NNS air dryer and filters have a Safety Class 2 bypass line and isolation valves to ensure air is provided for the ADS function in the event the dryer/filter become inoperable or plugged. A Safety Class 2 pressure transmitter which activates an annunciator in the main control room is provided downstream of the dryers to alert the operator to a malfunction and allow him to remote manually isolate and bypass the dryer/filter. Pressure transmitters are also provided on the PVLCS air accumulators as described in Section 9.3.6.

TABLE 1A-1 (Cont)

Item and Title	Position	FSAR Reference*
II.K.3.24 Space cooling for HPCI/RCIC, modifications	The River Bend Station RCIC system is designed to withstand a complete loss of offsite ac power. The RCIC system turbine room space coolers are provided with a backup emergency power supply to ensure that pump room temperatures are maintained below equipment qualification limits during periods when offsite power is unavailable.	5.4.6
II.K.3.25 Power on pump seals	The consequences of loss of cooling to the reactor recirculation pump seal coolers will be studied by GE and the BWR Owners' Group. The results and recommendations of the studies will be taken into account to determine if any modifications are necessary.	5.4.1
II.K.3.27 Common reference level	GSU has reviewed the BWR Owners' Group generic position on this item and agrees that the current reactor water level instrumentation will provide operators with reactor water level information that will permit the operators to make timely and correct decisions regarding reactor water control requirements. Therefore, no modification of the current main control room water level instrumentation is required on the basis of plant safety considerations.	4.4.6
II.K.3.28 Qualification of ADS accumulators	~~The BWR Owners' Group is studying, on a generic basis, the ability of the ADS valve accumulators to perform their functions during and following exposure to hostile environments. The results and recommendations of this study will be used to determine if any modifications are necessary.~~ INSERT B	~~6.3~~ 5.2.2.4.1
II.K.3.30 SB LOCA methods	SBA models used for River Bend Station are found in Chapter 15.6 of the FSAR. Qualification of these models was performed by General Electric (GE) and submitted to the NRC Office of Nuclear Reactor Regulation, on June 26, 1981, from R. H. Bucholz to D. G. Eisenhut. Qualification of the models has been verbally accepted by the NRC.	15.6 7

The River Bend Station air supply system for the automatic depressurization system (ADS) valves consists of two ASME III Division I, Class 2 air compressors and two non-nuclear safety compressors which feed two separate charging systems for the accumulators. Both ASME III compressors are powered from the preferred ac power supply systems and can be powered by on-site power. The system is sufficient to supply enough air capacity to cycle the valves open 4 to 5 times at atmospheric pressure. The safety grade ASME III compressors, ADS valves, accumulators, and associated equipment and instrumentation are designed to withstand its environment following an accident and perform its function. This position is consistent with LRG-II issue 8-RSB.

QUESTION 440.19 (5.4.6)

BWR operating experience has shown that the HPCI and RCIC systems have been rendered inoperable because of inadvertent leak detection isolations caused by equipment room area high differential temperature signal. The events occurred when there was a relatively sharp drop in outside temperature. As noted in Section 5.4.6.1.1.1, and in Table 5.2-8, RBS incorporates this type of RCIC and RHR (steam) isolation. Provide a discussion of the modifications that have been or will be made to prevent inadvertent isolations of this type which affect the availability and reliability of the RCIC and the RHR systems.

Secondly, provide the trip settings for isolation of the RHR and RCIC systems due to high area temperature in term of degrees above ambient temperature.

Also, discuss the method of specification that would be applied. Show that the setting could not be set too low and cause inadvertent isolation when the system is needed.

RESPONSE

INSERT A ~~An analysis is in progress to determine setpoints for isolation of the RHR and RCIC systems due to equipment area high differential temperature. The analysis includes effects of variations of the ambient temperature, and design of the ventilation system, heat sinks, and heat sources. A complete response to this question including setpoints will be provided in 1983~~.

The isolation trip settings for the RHR and RCIC systems are currently being developed in conjunction with the overall setpoint program for RBS.

The analysis to develop these setpoints considers the effects of variations in ambient temperature, ventilation system design, heat sinks and heat sources. Setpoints are based on room temperature transient response due to an assumed 5 GPM and 25 GPM steam leak. The setpoint due to a 5 GPM leak produces a trouble alarm with the 25 GPM setpoint generating an isolation signal. Since the auxiliary building ventilation system is designed to maintain a maximum room temperature of 122°F with a maximum heat load (all equipment operating) in the room, the 5 GPM trouble alarm and 25 GPM isolation trip point is set at points above 122°F to avoid inadvertient trips of the RHR and RCIC system.

FSAR Section 7.4.3.2.1.3 provides a discussion of the RHR and RCIC room cooling systems that is consistent with LRG-II positions 2-RSB(c) and 4-ASB.

TABLE 1A-1 (Cont)

Item and Title	Position	FSAR Reference*
II.K.3.24 Space cooling for HPCI/RCIC, modifications	The River Bend Station RCIC system is designed to withstand a complete loss of offsite ac power. The RCIC system turbine room space coolers are provided with a backup emergency power supply to ensure that pump room temperatures are maintained below equipment qualification limits during periods when offsite power is unavailable. ← INSERT C	5.4.6 & 9.4.3.2.1.3
II.K.3.25 Power on pump seals	The consequences of loss of cooling to the reactor recirculation pump seal coolers will be studied by GE and the BWR Owners' Group. The results and recommendations of the studies will be taken into account to determine if any modifications are necessary.	5.4.1
II.K.3.27 Common reference level	GSU has reviewed the BWR Owners' Group generic position on this item and agrees that the current reactor water level instrumentation will provide operators with reactor water level information that will permit the operators to make timely and correct decisions regarding reactor water control requirements. Therefore, no modification of the current main control room water level instrumentation is required on the basis of plant safety considerations.	4.4.6
II.K.3.28 Qualification of ADS accumulators	The BWR Owners' Group is studying, on a generic basis, the ability of the ADS valve accumulators to perform their functions during and following exposure to hostile environments. The results and recommendations of this study will be used to determine if any modifications are necessary.	6.3
II.K.3.30 SB LOCA methods	SBA models used for River Bend Station are found in Chapter 15.6 of the FSAR. Qualification of these models was performed by General Electric (GE) and submitted to the NRC Office of Nuclear Reactor Regulation, on June 26, 1981, from R. H. Bucholz to D. G. Eisenhut. Qualification of the models has been verbally accepted by the NRC.	15.6 7

This position is consistent with LRG-II issue 4-ASB/2-RSB(c).

Enclosure 3

RBS FSAR

QUESTION 440.35 (6.3)

Describe in detail the isolation provisions to demonstrate that the LPCS system (portions which interface with Reactor Coolant Pressure Boundary) complies with one of the acceptable system isolation requirements given in Branch Technical position RSB 5-1 of SRP 5.4.7.

RESPONSE

The response to this request ~~will be provided by November 1982.~~

is provided in the response to Question 440.29. This response is consistent with LRG-II position 2-ICSB.

Question 440.58 (5.4.7)

The alternate method to achieve cold shutdown requires additional clarification (see Question 440.32). Confirm that preoperational testing will be performed on the components of the alternate shutdown system to provide assurance of operability. We require plant-specific analysis to verify that sufficient flow capacity exists for all piping and valves required in the alternate shutdown method and that the RHR pump headflow requirements for the worst path resistance can be met. This plant-specific analysis is in addition to the information to be submitted under TMI Item II.D.1.

Response

The response to this request regarding plant-specific analysis is provided in revised Section 5.4.7.1.5. Preoperational testing will be performed on the components of the alternate shutdown system to provide assurance of operability.

5.4.7.1.5 Design Basis for Reliability and Operability

The design basis for the shutdown cooling mode of the RHR system is that this mode is controlled by the operator from the main control room. The only operations performed outside the main control room for a normal shutdown is manual operation of local flushing water admission valves, which are the means of providing clean water to the shutdown portions of the RHR system.

Two separate shutdown cooling loops are provided, and although both loops are required for shutdown under normal circumstances, the reactor coolant can be brought to 212°F in less than 20 hr with only one loop in operation. With the exception of the shutdown suction, shutdown return, and steam supply and condensate discharge lines, the entire RHR system is part of the ECCS and containment cooling system, and is therefore required to be designed with redundancy, flooding protection, piping protection, power separation, etc, required of such systems (see Section 6.3 for an explanation of the design bases for the ECCS). Shutdown suction and discharge valves are required to be powered from both offsite and standby emergency power for purposes of isolation and shutdown following a loss of offsite power. In the event either of the two shutdown supply valves fail to operate, an operator is sent out to operate the valve manually. If this is not feasible and the plant must be shut down as soon as possible, the alternate shutdown method is employed. In this procedure, water is drawn from the suppression pool, pumped through the RHR heat exchanger and delivered into the shroud region of the reactor. The vessel water is allowed to overflow the steam lines and discharges back to the suppression pool via the ADS valve discharge lines. A complete loop is thereby established, with sensible and decay heat being transferred to the pool and then to service water via the RHR heat exchanger. INSERT A The time required to achieve cold shutdown using the alternate shutdown cooling mode is less than the time to achieve cold shutdown using the normal shutdown cooling mode of the RHR system. 3

5.4.7.1.6 Design Basis for Protection from Physical Damage

Pumps A, B, and C are physically separated. Each is housed in a separate room. Rooms A and B contain their respective pumps and two RHR heat exchangers. Room C contains Pump C and the RHR discharge line fill pump. 3

The design basis for protection from physical damage, such as internally generated missiles, pipe break, and seismic effects, is discussed in Sections 3.5, 3.6, and 3.7, respectively.

A pressure drop calculation has been performed which confirms that both A and B loops of RHR are capable of performing alternate shutdown cooling operations under conditions postulating worst case flow path hydraulic resistance.

Question 440.57 (5.4.7)

The response to Question 440.28 requires additional clarification. NPSH values required at 3 ft. above mounting flange (typical test) are shown in figures 6.3-3, 6.3-6 and 6.3-7 for HPCS, LPCS and RHR pumps. Are these values derived from plant-specific tests conducted for RBS pumps? What is meant by "typical test"?

In the NPSH calculations given in Section 6.3.2.2, the NPSH requirements are specified relative to a point 2 ft. above the pump mounting flange. Explain how this is consistent with Figures 6.3-3, 6.3-6 and 6.3-7.

Describe in a detailed and consistent manner the NPSH required and the NPSH available for the ECCS pumps. Revise FSAR figures 6.3-3, 6.3-6 and 6.3-7 to show both NPSH required and NPSH available.

Response

The relationship between NPSH available values in Section 6.3.2.2 and the NPSH required values shown on Figures 6.3-3, 6.3-6, and 6.3-7 for the ECCS pumps is clarified in revised Section 6.3.2.2 and Figure 5.4-13. This discussion is consistent with LRG-II position 7-RSB.

$$NPSH_{min} = P_B + L_H - V_p - h_f - \frac{V^2}{2g} - h_s$$

$$= 35.35 + 10.75 - 33.97 - 3.20 - 0.77 - 2.40$$

$$= 5.76 \text{ ft}$$

LPCI

This ECCS mode of RHR system operation constitutes the limiting condition of NPSH available for the RHR pumps. With all other conditions equal the NPSH available for RHR pump A is the least of the three due to the greatest equivalent length of suction piping and fittings. The ECCS mode of operation is the worst case based upon the fluid velocity head. Accordingly, the following NPSH calculation is for this pump only while performing its ECCS function. 5

Evaluating all factors as defined above:

P_B = 14.7 psia (144 in²/ft²)/(59.9 lb/ft³) = 35.34 ft

L_H = 83.25-75.5 ft = 10.75 ft

V_p = (14.1 psia) (144 in²/ft²)/(59.9 lb/ft³) = 33.90 ft

(Based on maximum hypothetical suppression pool temp of 210°F) 9

Frictional losses due to flow through 20 in SCH STD and 20 in SCH XS pipe and associated fittings.

h_f = 4.10 ft

Then, evaluating the fluid velocity head

$\frac{V^2}{2g}$ = (6.67 ft/sec)²/2(32.2 ft/sec²) = 0.69 ft

h_s = 1.0 psi (144 in²/ft²)/(59.0 lb/ft³) = 2.40 ft

$$NPSH_{min} = 35.34 + 10.75 - 33.90 - 4.10 - 0.69 - 2.40$$

$$= 5.00 \text{ ft}$$

9

Pump characteristic curves are given in Fig. 6.3-3 (HPCS), 6.3-6 (LPCS), and 6.3-7 (LPCI).

INSERT A

The NPSH calculations given in this section used a reference elevation of 2 ft. above the pump mounting flange and a desired NPSH available of ≥ 5 ft. since these requirements were specified diagrams in the respective systems' process to allow for some design margin. The ≥ 5 ft. value of NPSH available does not relate to actual pump performance requirements.

The graphs of NPSH required shown on Figures 6.3-3, 6.3-6 and 6.3-7 are based on performance tests conducted by the pump manufacturer. The comparison table below demonstrates that all the ECCS pumps have adequate margin of NPSH available over actual NPSH required:

Pump	NPSH Available Adjusted to A Reference Elevation 3 Ft. Above Pump Mounting Flange	NPSH Required 3 Ft. Above Pump Mounting Flange Based on Performance Test By Pump Vendor
HPCS	4.91 ft.	1.00 ft.
LPCS	4.76 ft.	0.30 ft.
RHR(LPCI)	4.00 ft.	0.30 ft.

requirements of Regulatory Guide 1.1, the following design features/criteria were applied to calculations of NPSH available for ECCS suction piping from the suppression pool:

1. Suppression pool level is assumed to be at its minimum drawdown level of 83 ft 3 in.

2. A 1 psi pressure drop across the suppression pool strainers is assumed.

3. Pumps are assumed to be operating at maximum run-out flow.

4. The NPSH available is required to be 5 ft at a point 2 ft above the pump mounting flange.

5. All ECCS pump suction lines are run at a constant elevation from their points of origin in the suppression pool to their respective pump suction flanges. There are no local elevation changes in these piping runs. Therefore, liquid continuity is ensured throughout the entire length of the piping.

INSERT B

5 The following discussion with supporting calculations demonstrates that the available NPSH at all points in ECCS pump suction is adequate to preclude local flashing and pump cavitation under worst postulated conditions.

<u>HPCS</u>

The HPCS pump can take suction from the condensate storage tank or the suppression pool. However, the combination of minimum static head, maximum fluid vapor pressure, and frictional losses in piping and fittings make suction from the suppression pool the limiting condition of NPSH available.

$$NPSH_{min} = P_B + L_H - V_p - h_f - \frac{V^2}{2g} - h_s$$

Where

P_B = Barometric pressure of containment, absolute (ft)

L_H = Net static suction head from minimum drawdown suppression pool level at 83 ft 3 in. elevation to el 72 ft - 6 in. (a point 2 ft above top of pump mounting flange)

V_p = Absolute vapor pressure of liquid at maximum (hypothetical) suppression pool temperature

5. (cont'd.)

The HPCS and LPCS suppression pool suction strainer centerline elevation is 75.5 ft. (LPCI @ 73.4ft.). A minimum ECCS suction strainer submergence of greater than 7.5 ft. is maintained to preclude vortex formation.

MODE A-1 (SEE NOTES 3 & 13)

POSITION	1	2	3	4	5	6	$7_{A,B}$	$8_{A,B}$	9	10	48	11	29
FLOW GPM	—	5050										5050	—
PRESSURE PSIA	29.7 / 14.7												53.7 / 38.7
TEMPERATURE °F	—	170 / 40										170 / 40	—
MAX PRESSURE DROP FEET					TDH = 275				ΔH = 70			ΔH = 40	

LOOP A & B
LOOP C
SEE NOTE 7 TYP. ALL TABLES

MODE A-2 SEE NOTE 13

POSITION	1	2	3
FLOW GPM	—	6060	
PRESSURE PSIA	14.7		
TEMPERATURE °F	—	160 / 90	
MAX PRESSURE DROP FEET			

LOOP A & B

MODE B (SEE NOTE 20)

POSITION	1	2_B	3_B	4_B	5_B	6_B	18_B	19_B	9_B	10_B	13_B	53_B	44_B	43_B	24_B	1		60_B	61_B
FLOW GPM	—	5050													5050	—		5800	5800
PRESSURE PSIA	29.7 / 14.7															29.7 / 14.7			
TEMPERATURE °F	—	185					185	134.9							134.9	—		95	138.6
MAX PRESSURE DROP FEET					TDH = 275														

HEAT REMOVAL CAPABILITY PER HX LOOP 126.4 $\times 10^6$ BTU/HR (1 HX OPERATING)

MODE C-1 RX PRESSURE 1000 PSIG

POSITION		29	35	$36_{A,B}$	$37_{A,B}$	$17_{A,B}$	$18_{A,B}$	$19_{A,B}$	$20_{A,B}$	$38_{A,B}$	$39_{A,B}$	$40_{A,B}$	41	42	[illegible]	$44_{A,B}$	$34_{A,B}$	7		$60_{A,B}$	$61_{A,B}$
FLOW - SEE NOTE 14		—	153.4	76.7			76.7	153				153	306	306	153	153	153	—		5600	5800
PRESSURE PSIA		1040			*214.7*									*59.7*				14.7			
TEMPERATURE °F		—	548	548	388	388	388	140									140	—		95	123.7
PRESSURE DROP - PSI		ΔP= 825							ΔP= 200 ΔP= 155												

COND TO RCIC
COND. TO POOL

HEAT REMOVAL CAPABILITY PER HX LOOP 63.3 $\times 10^6$ BTU/HR (2 HX'S OPERATING)

3 3 3 3

MODE C-2 RX PRESSURE 1000 PSIG

POSITION			29	35	36_A	37_A	17_A	18_A	19_A	20_A	38_A	39_A	40_A	41	42			60_A	61_A
FLOW - SEE NOTE 14			—	109.3				109.3	218						218			5800	5800
PRESSURE PSIA			1040			*214.7*									*59.7*				
TEMPERATURE °F			—	548	548	388	388	388	140						140			95	135.9
PRESSURE DROP - PSI			ΔP=825								ΔP= 155								

3

HEAT REMOVAL CAPABILITY PER STEAM CONDENSING HX LOOP 118.6 $\times 10^6$ BTU/HR (1 HX STEAM CONDENSING)

3

MODE C-1 CONT'D (SEE NOTES 13 & 20)

POSITION	1	2_B	3_B	4_B	5_B	6_B	18_B	19_B	9_B	10_B	13_B	53_B	44_B	43_B	24_B	1		60_B	61_B
FLOW GPM	—	5050													5050	—		5800	5800
PRESSURE PSIA	14.7															14.7			
TEMPERATURE °F	—	120					120	106.1							106.1	—		95	107.1
MAX PRESSURE DROP FEET					TDH = 275														

HEAT REMOVAL CAPABILITY PER POOL COOLING HX LOOP 35.1 $\times 10^6$ BTU/HR (1 HX OPERATING)

MODE C-3 RX PRESSURE 135 PSIG

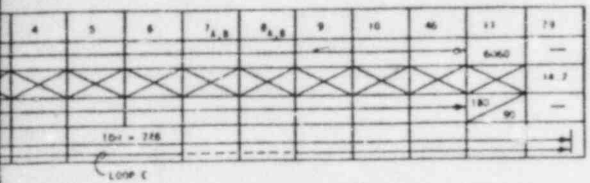
POSITION			29	35	$36_{A,B}$	$37_{A,B}$	$17_{A,B}$	$18_{A,B}$	$19_{A,B}$	$20_{A,B}$	$38_{A,B}$	$39_{A,B}$	$40_{A,B}$	41	42			$60_{A,B}$	$61_{A,B}$
FLOW - SEE NOTE 14			—	94	47			47	94				94	188	188			5800	5800
PRESSURE PSIA			150					>60							59.7 / 14.7				
TEMPERATURE °F			—	358				323	140						140			95	112.6
PRESSURE DROP - PSI								ΔP= 90/135											

HEAT REMOVAL CAPABILITY PER STEAM CONDENSING HX LOOP 51.1 $\times 10^6$ BTU/HR (2 HX'S STEAM CONDENSING)

MODE C-4 RX PRESSURE 135 PSIG

POSITION			29	35	36_A	37_A	17_A	18_A	19_A	20_A	38_A	39_A	40_A	41	42			60_A	61_A
FLOW - SEE NOTE 14			—	79.1				79.1	158						158			5800	5800
PRESSURE PSIA			150					>60							59.7 / 14.7				
TEMPERATURE °F			—	356				323	140						140			95	124.6
PRESSURE DROP - PSI							ΔP= 90/135												

HEAT REMOVAL CAPABILITY PER STEAM CONDENSING HX LOOP 85.9 $\times 10^6$ BTU/HR (1 HX STEAM CONDENSING)



MODES

A-1 LOW PRESSURE COOLANT INJECTION (LPCI) RECIRCULATION LINE BREAK IN EITHER SIDE AND THREE PUMPS OPERATING. ONE STRAINER 50 PLUGGED.

A-2 LOW PRESSURE COOLANT INJECTION (LPCI) RECIRCULATION LINE BREAK IN EITHER SIDE AND THREE PUMPS OPERATING. ONE STRAINER 50 PLUGGED (VESSEL PRESSURE 10 PSIG)

B POST ACCIDENT SUPPRESSION POOL COOLING WITH ONE PUMP OPERATION AND STRAINER 50 PLUGGED. (PEAK SUPPRESSION POOL TEMPERATURE)

C-1 REACTOR STEAM CONDENSING - 2HX STEAM CONDENSING (AT 1/2 HOUR)

C-2 REACTOR STEAM CONDENSING - 1HX STEAM CONDENSING (AT 1-1/2 HOURS) AND 1HX POOL COOLING.

C-3 REACTOR STEAM CONDENSING - 2HX STEAM CONDENSING (AT 4 HOURS)

C-4 REACTOR STEAM CONDENSING - 1HX STEAM CONDENSING (AT 6 HOURS)

D-1 INITIATION OF SHUTDOWN COOLING AFTER BLOWDOWN TO MAIN CONDENSER AT 4 HOURS.

D-2 CONTINUATION OF SHUTDOWN COOLING AT 12.5 HOURS.

E-1 CONTINUATION OF SHUTDOWN COOLING AT 20 HOURS AND FUNCTIONAL PUMP TEST AFTER SHUTDOWN.

E-2 CONTINUATION OF SHUTDOWN COOLING WITH RETURN TO UPPER CONTAINMENT POOL AT GREATER THAN 20 HOURS AND FUNCTIONAL PUMP TEST AFTER SHUTDOWN.

F RHR SYSTEM TEST DURING PLANT OPERATION

G MINIMUM FLOW BYPASS MODE. 2 SUCTION SOURCES.

S SYSTEM ON STANDBY DUTY

LEGEND:

ΔH	-HEAD LOSS
ΔP	-PRESSURE LOSS
RX PRESS	-REACTOR VESSEL PRESSURE
SOH	-SHUTOFF HEAD
TDH	-TOTAL DYNAMIC HEAD

REFERENCE DOCUMENTS:	MPL ITEM NO.
1. RCIC SYSTEM PROCESS DIAGRAM	E51-1020
2. RECIRC SYSTEM DESIGN SPEC DATA	B33-4010
3. LOW PRESSURE CORE SPRAY SYSTEM PD	E21-1020
4. NUCLEAR BOILER SYSTEM PROCESS DIAGRAM	B21-1020
5. REACTOR WATER CLEANUP SYSTEM PD	G33-1030

SUPPORTING DOCUMENTS:

1. PIPING & INSTRUMENT SYMBOLS	A42-1010

NOTES:

1.

2. PIPING BETWEEN POINTS WITH EMPTY DATA BLANKS (SEE ALSO TABLE 3) SHALL BE SIZED BY CUSTOMER OR AE BASED ON SPECIFIED OPERATING CONDITIONS. EMPTY DATA BLANKS CAN BE FILLED IN BASED ON ACTUAL ARRANGEMENT OR EQUIVALENT HYDRAULIC DATA SUBMITTED TO BWRSD FOR REVIEW.
⊠ ------INDICATES THE DATA IS NOT SIGNIFICANT.

3. SHOWN AS TYPICAL FOR ONE LOOP. IF LOOPS ON SIDE I AND SIDE II ARE NOT SYMETRICALLY ARRANGED, VALUES FOR BOTH SIDES SHALL BE SUBMITTED.

4. ΔH VALUES FOR EQUIPMENT WITHIN GE SCOPE ARE AS NOTED.

5. ELEVATIONS ARE NOT INCLUDED IN ΔP VALUES GIVEN. ELEVATIONS SHALL BE INCLUDED WHEN DETERMINING FINAL VALUES FOR THE EMPTY DATA BLANKS.

6. X/Y ------INDICATED MAXIMUM (X) AND MINIMUM (Y) VALUES FOR THE MODE SPECIFIED.

7. DASHED LINES INDICATE FLOW DOES NOT PASS THRU THESE POINTS. SOLID LINES INDICATE FLOW DOES PASS THRU THESE POINTS.

8. THE NPSH AVAILABLE IN MODES A-2, B, & D-1, AT A REFERENCE LOCATION 2 FEET ABOVE THE PUMP MOUNTING FLANGE MUST EQUAL OR EXCEED 5 FT. ASSUMING SATURATION TEMPERATURES OF 212°F AND 350°F RESPECTIVELY. THE NPSH AVAILABLE AT THE PUMP SUCTION NOZZLE MUST EQUAL OR EXCEED THIS VALUE PLUS THE DIFFERENCE IN ELEVATION BETWEEN THE REFERENCE LOCATION AND THE CENTER-LINE OF THE PUMP SUCTION NOZZLE.

3 9. PIPING SYSTEM DESIGN PRESSURE AND TEMPERATURE AND THE ESTIMATED LINE SIZES ARE FOR INFORMATION ONLY. ACTUAL DESIGN PRESSURE AND TEMPERATURE AND LINE SIZES AS DETERMINED BY PIPING DESIGNER SHALL MEET THE PROCESS DATA HYDRAULIC REQUIREMENTS. REFER TO HARDWARE DWGS. FOR NOZZLE SIZES ON GE SUPPLIED EQUIPMENT.

10. FUEL POOL CONNECTIONS MUST PROVIDE ADEQUATE NPSH TO AVOID PUMP CAVITION AND AT THE SAME TIME PROVIDE FOR GREATER THAN MINIMUM PUMP FLOW.

11. TABLE 1 INDICATES VALVE POSITION DURING VARIOUS MODES OF OPERATION.

12.

13. TYPICAL VALUES FOR MAX. SUPPRESSION POOL TEMP SHOWN. FINAL TEMPERATURE DEPENDS ON INITIAL POOL WATER TEMPERATURE & POOL WATER VOLUME.

14. WATER FLOWS ARE IN GPM, STEAM FLOWS ARE IN 1000LBS/HR.

3 15. MAXIMUM SOH 780 FEET

16. SERVICE WATER CROSSTIE SHALL BE SIZED TO FLOW 500 GPM AND ENOUGH HEAD TO FLOOD THE CONTAINMENT.

17. THE WEIGHT OF WATER IN THE SHUTDOWN COOLING SUBSYSTEM PIPING, INCLUDING THE HEAT EXCHANGERS AND PUMPS SHALL NOT EXCEED 235,000 LBS AT 75°F TO PREVENT DILUTION OF STANDBY LIQUID CONTROL NEUTRON ABSORBER BELOW MINIMUM REQUIREMENTS.

18. SEE REFERENCE 5 FOR SUPPLEMENTAL FLOWS ENTERING DOWNSTREAM OF E12-F050 DURING NORMAL PLANT OPERATIONS.

19. FLOW SHOWN IS A MAXIMUM, ACTUAL FLOW WILL BE INDICATED LATER.

20. MAXIMUM SHELL SIDE FLOW RATE IS 5550 GPM.

21. FLOW SHOWN AT POSITION 71 DOES NOT INCLUDE FLOW FROM FUEL POOL COOLING AND CLEANUP SYSTEM.

22. SEE SYSTEM DATA SHEET FOR SUGGESTED VALVE SIZING.

3 23. SUCTION TEMPERATURE AND PRESSURE ARE FOR LOOPS A & B ONLY. LOOP C CONDITIONS ARE 0 PSIG VESSEL PRESSURE AND 125°F.

24. The HX inlet pressure shall be greater than 60 psia to minimize the possibility of flow-induced vibration.

SOURCE: 762E425AA, SHT.1, REV.4

FIGURE 5.4-13

RHR PROCESS DIAGRAM
AND DATA
SHEET 1 OF 3

RIVER BEND STATION
FINAL SAFETY ANALYSIS REPORT

QUESTION 440.37 (6.3)

Your FSAR states that no operator action is required until 10 minutes after an accident. It is our position that no operator action be required for 20 minutes after an accident. Discuss the consequences of not performing operator actions until 20 minutes after a LOCA (LRG II issue-4-RSB).

RESPONSE

River Bend Station operators are not required to take any action before 20 minutes following a LOCA to maintain the safety of the plant. This is consistent with LRG-II
9 position 4-RSB. ~~except that no~~ ADS modifications are ~~necessary as~~ delineated in FSAR Table 1A-1 under TMI item II.K.3.18 ~~because of RBS plant specific considerations.~~ and FSAR Section 7.3.1.1.1.2.

QUESTION 440.42 (6.3)

The SRP 6.3 does not allow credit for operator action for 20 min following a loss-of-coolant accident (LOCA). The FSAR states no operator action is required for at least 10 min. The applicant should confirm that no operator action is required until 20 min after the LOCA, or provide technical justification and an associated data base to support a time less than 20 min. The applicant should identify the manual actions which must be performed to prevent safety criteria from being exceeded following a LOCA over the break spectrum, including single failures. It should also be shown that adequate alarms, instrumentation, and time will be available to the operator to perform manual actions necessary to prevent safety criteria from being exceeded (LRG-II issue 4-RSB).

RESPONSE

~~The response to this request will be provided by November 1982~~.

No operator action is accounted for the first 20 minutes following a loss-of-coolant accident (LOCA). FSAR Section 7.3.1.1.1.2 and Appendix 1A item II.K.3.18 provides further clarification.

2. ADS Operation

Schematic arrangements of system mechanical equipment and operator information displays are shown in Fig. 5.1-3. ADS component control logic and operator information displays are shown in Fig. 7.3-2. Instrument location drawings and elementary diagrams are identified in Section 1.7.

The ADS consists of two redundant and independent trip systems, trip systems A and B. ADS trip system A actuates the A solenoid air pilot valve on each ADS SRV. Similarly, ADS trip system B actuates the B solenoid air pilot valve on each ADS SRV. Actuation of either solenoid pilot valve causes the ADS SRV to open and provide depressurization. To prevent inadvertent actuation of the ADS, two channels of logic for each ADS trip system (A and B) are used. Both channels must be activated to actuate an ADS trip system.

Each trip channel contains a single input from a drywell high pressure transmitter. One trip channel includes two differential pressure sensor inputs monitoring reactor vessel low water level (trip levels 1 and 3). The low water level 3 trip provides confirmation of a reactor vessel low water level condition. The second trip channel is redundant, except the low water level confirmation signal is omitted. ← INSERT A

To assure that adequate makeup water is available after the vessel has been depressurized, each trip channel includes a pump discharge pressure permissive signal indicating LPCI or LPCS system available for vessel water makeup. Any one of the three LPCI pumps or the LPCS pump available for reactor coolant makeup is sufficient to permit automatic depressurization (one pump each per trip system).

After receipt of the initiation signals and after a delay provided by timers, each of the two solenoid air pilot valves is energized. This allows pneumatic pressure from the accumulator to act on the air cylinder operator. Each ADS trip system has a time delay that can be reset manually to delay system initiation. The time delay is selected to be within a period that allows the HPCS to perform its function prior to ADS initiation. In the event of HPCS failure, the time delay period is selected to allow initiation of ADS, LPCI, and LPCS in time to maintain the fuel barrier temperature within acceptable limits. If reactor vessel water level is restored by HPCS prior to the end of the time delay, ADS initiation is prevented.

To insure automatic depressurization for LOCA's or other postulated events that do not produce a high drywell pressure signal, the ADS trip system provides automatic backup to operator action. This modification consists of adding a bypass to the drywell pressure signal with a set time delay and the addition of a manual ADS inhibit. The bypass is incorporated into the system logic by the addition of a bypass timer actuated on reactor water level 1. This timer provides a nominal eight minute time delay with the exact timer setpoint determined based on not exceeding 10CFR50.46 acceptance criteria for LOCA events and still being compatible with the RBS ATWS design. Starting of the bypass timer also activates an alarm that the bypass logic has been activated. After the time delay, the time delay relay contacts located in the high drywell pressure signal bypass circuit are closed, effecting the bypass. The existing 105 second timer is then started and the ADS solenoid energized, after the timer runout, provided that at least one low pressure pump in that division is running. The bypass timers are automatically reset when the low water level signal has cleared or the reset pushbutton is pressed.

TABLE 1A-1 (Cont)

Item and Title	Position	FSAR Reference*
II.K.3.18 ADS actuation	~~The current ADS logic provides a satisfactory backup to manual action since, in the River Bend Station design, drywell cooling is lost when the reactor water level reaches low level (Level 1). This loss of cooling causes the drywell temperature to increase and, consequently, the drywell pressure to rise. As stated in the BWROG position, submitted March 31, 1981, the drywell pressure reaches the 2 psig setpoint required for ADS initiation in 5 to 10 min resulting in ADS actuation if the water level has not been restored above Level 1.~~ INSERT B In addition, the BWROG symptom-oriented EPGs provide explicit instructions on when to manually depressurize the vessel if the high pressure systems cannot maintain inventory. Implementation of these improved procedures and operator training provides adequate assurance that the vessel is depressurized, if required.	~~7.3~~
II.K.3.21 Restart of LPCS and LPCI	GSU has concluded from its review of the River Bend Station design that, in light of the BWR Owner's Group position submitted to the NRC on December 29, 1980 (April 20, 1982 letter from D. B. Waters, BWROG Chairman to D. G. Eisenhut, NRC), no modifications should be made to the control logic of the existing LPCI and LPCS systems. It has been determined that modifications to the River Bend Station HPCS system to automate restart on low level following manual trip are not required for safe operation. The LRG-II position 1-RSB which supports this conclusion has been accepted (February 26, 1982 letter from J. R. Miller, NRC to D. L. Holtzscher, LRG-II Chairman).	7.3
II.K.3.22 RCIC suction	River Bend Station design provides automatic switchover of the RCIC system suction from the condensate storage tank to the suppression pool when condensate storage tank level is low. Therefore, River Bend Station design satisfies the intent of this item.	7.4

7

GSU is modifying its automatic depressurization trip system with an eight minute bypass timer on the drywell pressure signal which provides an automatic backup to operator action to ensure adequate core cooling. This modification conforms to option number four of the BWR Owner's Group position submitted March 31, 1981 to the NRC.

QUESTION 440.43 (6.3)

Address the inadvertent closure of the reactor recirculation system line suction valve as a single failure in the LOCA analysis, for the break size most affected by this failure (LRG II issue-10-RSB).

RESPONSE

~~The response to this request will be provided by November 1982.~~

River Bend Station endorses LRG-II position 10-RSB which bounds the failure of a recirculation line suction valve following a LOCA.

QUESTION 440.59

The response to Question 440.50 is unacceptable. Provide a quantitative analysis for operation with partial feedwater heating. The basis for the maximum feedwater temperature reduction for a partial feedwater heating event should be provided (e.g., specific turbine operational limitations).

Response:

The requested analysis will be provided for staff review and approval prior to operation with partial feedwater heating if a decision is made to operate in this mode.

Question 440.53

During meetings with General Electric, the staff has discussed the use of nonsafety-grade equipment for anticipated transient analyses. It is our understanding that one of the most limiting events is the feedwater controller failure (maximum flow demand). For this transient, the plant operating equipment that have a significant role in mitigating this event are the turbine bypass system and the reactor vessel high water level (Level 8) trip that closes the turbine stop valves. To assure an acceptable level of performance, it is the staff's position that this equipment be identified in the plant Technical Specifications with regard to availability, set points, and surveillance testing. Submit your plan for implementing this requirement along with any system modifications that may be required to fulfill the requirements (LRG II issue 11-RSB).

RESPONSE

GSU endorses the LRG-II issue 11-RSB which states that the most limiting combination of failures is a proper functioning of the Level 8 trip with failure of the bypass valves to open. This event would resemble a turbine trip without bypass but would be less severe than the one presented in the River Bend Station FSAR because of the reduced power at the time of the trip. The RBS Proposed Technical Specifications will identify the equipment availability, set points, and surveillance testing as it applies to this analysis.

QUESTION 440.45 (15.0.3)

On page 15.0-6 of the RBS FSAR, it is stated:

"Reference 1 suggests that the transient and accident scenarios should now include 'and' (multi-failure) event sequences. The format request follows:

1. For initiating occurrence - an equipment failure or an operator error.

2. For single equipment failure - or operator error analysis, another equipment failure, or failures and/or another operator error or errors.

This certainly is considered a new requirement and the impact will need to be completely evaluated."

We don't consider the above requirement as new. [Ref: NUREG-75/087 - SRP 15.1.1-3 "An incident of moderate frequency in combination with any single active component failure or single operator error, should not result in loss of function of any barrier other than fuel cladding] We require the evaluation stated above by the applicant. Using the above criteria, analyze the most limiting transients to verify that fuel cladding integrity will be maintained and the CPR remains above the MCPR safety limit.

RESPONSE

~~The response to this request will be provided by November 1982.~~

Chapter 15 contains evaluations of postulated single failures associated with anticipated transients. Plant nuclear safety operational analysis (NOSA), the system-level qualitative-type failure modes and effects analysis of essential protective sequences in Appendix 15A, shows compliance with the single active component failure or the single operator error criteria.

The five most limiting analyzed Chapter 15 transients are:

(1) Loss of Feedwater Heater-Manual Flow Control (Subsection 15.1.1)

(2) Feedwater Control Failure-Maximum Demand (Subsection 15.1.2)

(3) Pressure Regulation Downscale Failure (Subsection 15.2.2)

(4) Generator Load Rejection with Failure of Bypass (Subsection 15.2.2)

(5) Turbine Trip with Failure of Bypass (Subsection 15.2.3)

In reviewing the expected sequence of events utilized in simulating the plant performance for each of these transients, it was determined that postulating a single active safety-related component failure does not alter the transients. For the feedwater control failure - maximum demand transient in which credit is taken for full turbine bypass capacity, a single active component failure would result in the loss of one of the turbine bypass paths. However, the consequence of losing one bypass path is not expected to result in fuel failure.

15.0.3.2 Sequence of Events and Systems Operations

Each transient or accident is discussed and evaluated in terms of:

1. Step-by-step sequence of events from initiation to final stabilized condition.

2. Extent to which normally operating plant instrumentation and controls are assumed to function.

3. Extent to which plant and reactor protection systems are required to function.

4. Credit taken for the functioning of normally operating plant systems.

5. Operation of engineered safety systems that is required.

6. Effect of a single failure or an operator error on the event.

15.0.3.2.1 Single Failures or Operator Errors

15.0.3.2.1.1 General

INSERT →

~~This section discusses a very important concept pertaining to the application of single failures and operator errors to analyses of the postulated events. Single active component failure (SACF) criteria have been required and successfully applied on past NRC-approved docket applications to DBA categories only. Reference 1 infers that a "single failures and operator errors" requirement should be applied to transient events (both high, moderate, and low probability occurrences) as well as accident (very low probability) situations.~~

~~Transient evaluations have been judged against a criteria of one single equipment failure (SEF) "or" one single operator error (SOE) as the initiating event, with no additional single failure assumptions to the protective sequences, although a great majority of these protective sequences utilized safety systems which can accommodate SACF aspects. Even under these postulated events, the plant damage allowances or limits were very much the same as those for normal operation.~~

~~Reference 1 suggests that the transient and accident scenarios should now include "and" (multi-failure) event sequences. The format request follows:~~

1. ~~For initiating occurrence - an equipment failure or an operator error.~~

2. ~~For single equipment failure - or operator error analysis, another equipment failure, or failures and/or another operator error or errors.~~

~~This certainly is considered a new requirement and the impact will need to be completely evaluated. While this is under consideration, General Electric Company (GE) has evaluated and presented some transients and accidents in this chapter in the preceding new requirement manner.~~

~~Event categorization relative to transient and accident analysis is discussed here. If the evaluation is done according to the new multi-failure methods, the event frequency categories should be modified.~~

~~The original categorization of events was based on frequency of the initiating event alone, and thus the allowance or limit was accordingly established based on that high frequency level. With the introduction of additional assumptions and conditions (initial event and SEF and/or SOE), the total event would now fall into a lower frequency/probability category. Thus, less restrictive limits or allowances should be applied in the analysis of transients and accidents. This certainly needs to be considered and evaluated.~~

~~GE has evaluated and presented the transients and accidents in this chapter by the more restrictive old allowances and limits of the event categorization presently in effect.~~

~~Most events postulated for consideration are already the results of single equipment failures or single operator errors that have been postulated during any normal or planned mode of plant operations. The types of operational single failures and operator errors considered as initiating events and subsequent protective sequence challenges are identified in the following subsections.~~

15.0.3.2.1.2 Initiating Event Analysis

1. The undesired opening or closing of any single valve (a check valve is not assumed to close against normal flow)

Insert

Chapter 15 contains evaluations of postulated single failures associated with anticipated transients. Plant nuclear safety operational analysis (NOSA), the system-level qualitative-type failure modes and effects analysis of essential protective sequences in Appendix 15A, shows compliance with the single active component failure or the single operator error criteria.

RBS FSAR

QUESTION 440.47 (15)

Even though "Failure of RHR Shutdown Cooling" transient is shown in Table 15.0-1, the referred text 15.2.9 is not given in the FSAR. Submit the complete Section 15.2.9, "Failure of RHR Shutdown Cooling," as given by other BWR owners for staff review.

RESPONSE

The response to this request is ~~will be~~ provided in ~~by November 1982.~~ new Section 15.2.9.

15.2.9 Failure of RHR Shutdown Cooling

Normally, in evaluating component failure associated with the RHR system in the shutdown cooling mode, active pumps or instrumentation (all of which are redundant for safety system portions of the RHR system) are assumed to fail. For purposes of the worst-case analysis, the single recirculation loop suction valve to the redundant RHR loops is assumed to fail. This failure would still leave two complete RHR loops for LPCI and pool cooling minus the normal RHR shutdown cooling loop connection. Although the valve could be manually opened, it is assumed to fail.

15.2.9.1 Identification of Causes and Frequency Classification

15.2.9.1.1 Identification of Causes

The plant is operating at 102% rated power when a loss of offsite power occurs, causing multiple safety-relief valve actuation and subsequent heatup of the suppression pool. Reactor vessel depressurization is initiated to bring the reactor pressure to approximately 100 psig. Concurrent with the loss of offsite power an additional single failure occurs which prevents the operator from establishing the normal shutdown cooling path through the RHR shutdown cooling lines. The operator then establishes a shutdown cooling path for the vessel through the ADS valves and vessel inventory makeup.

15.2.9.1.2 Frequency Classification

Recent analytical evaluations of this event have used additional worst case assumptions. These inlcuded:

(1) Loss of all offsite ac power,

(2) Utilization of safety-grade equipment only, and

(3) Operator action after 10 minutes

These assumptions change the initial incident (malfunction of RHR suction valve) from a moderate-frequency incident to a classification in the design basis accident status. However, the event is evaluated as a moderate frequency event.

15.2.9.2 Sequence of Events and System Operation

15.2.9.2.1 Sequence of Events

The sequence of events is shown in Table 15.2-14.

The following is the sequence of operator actions expected during the course of the events when no immediate restart is assumed. The operator should:

1. Following the scram, verify all rods in.

2. Check that diesel generators start and carry the vital loads.

3. Check that relays on the RPS drop out.

4. Check that both RCIC and HPCS start when reactor vessel level drops to the initiation point after the relief valve opens.

5. Break vacuum before the loss of sealing steam occurs.

6. Check T-G auxiliaries during coastdown.

7. When both the reactor pressure and level are under control, secure both HPCS and RCIC as necessary.

8. At 10 minutes into the transient, initiate suppression pool cooling (again for purposes of this analysis, it is assumed that only one RHR heat exchanger is available);

9. Initiate RPV shutdown depressurization by manual actuation of 7 ADS valves;

10. After the RPV is depressurized to approximately 100 psig, attempt to open one of the two RHR shutdown cooling suction valves. These attempts are assumed unsuccessful.

11. At 100 psig RPV pressure, use ADS to establish a closed cooling path as described in the notes for Figure 15.2-12.

12. Complete the scram report and survey the maintenance requirements.

15.2.9.2.2 System Operation

Plant instrumentation and control is assumed to function normally except as noted. In this evaluation, credit is taken for the plant and reactor protection systems and/or the use of ESF.

15.2.9.3 Core and System Performance

15.2.9.3.1 Methods, Assumptions, and Conditions

An event that can directly cause reactor vessel water temperature to increase is one in which the energy removal rate is less than the decay heat rate. The applicable event is loss of RHR shutdown cooling. This event can occur only during the low pressure portion of a normal reactor shutdown and cooldown, when the RHR system is operating in the shutdown cooling mode. During this time the critical power ratio remains high and nucleate boiling heat transfer is not exceeded at any time. Therefore, the core thermal safety margin remains essentially unchanged. The 10-minute time period assumed for operator action is an estimate of how long it would take the operator

to initiate the necessary actions; it is not a time by which he must initiate action.

15.2.9.3.2 Mathematical Model

In evaluation of this event, the important parameters to consider are reactor depressurization rate and suppression pool temperature. Models used for this evaluation are described in References 4 and 5.

15.2.9.3.3 Input Parameters and Initial Conditions

Table 15.2-15 shows the input parameters and initial conditions used in evaluation of this event.

15.2.9.3.4 Results

For most single failures that could result in loss of shutdown cooling, no unique safety actions are required. In these cases, shutdown cooling is simply re-established using other normal shutdown cooling equipment. In cases where both of the RHR shutdown cooling suction valves cannot be opened, alternate paths are available to accomplish the shutdown cooling function (Figure 15.2-11).

The analysis demonstrates the capability to safely transfer fission product decay heat and other residual heat from the reactor core at a rate such that the specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded. The evaluation assures that the safety function can be accomplished assuming a worst-case single failure.

The alternate cooldown path chosen to accomplish the shutdown cooling function utilizes the RHR and ADS or normal relief valve systems. For more detail, see Reference 3 and Figure 15.2-12.

The alternate shutdown systems are capable of performing the function of transferring heat from the reactor to the environment using only safety-grade systems. Even if it is additionally postulated that all of the ADS or relief valves discharge piping break, the shutdown cooling function can eventually be accomplished as the cooling water runs directly out of the ADS or safety/relief valves, flooding into the drywell and then into the suppression pool.

These systems also have suitable redundancy in components such that their safety function can be accomplished assuming an additional single failure in either power mode. This applies for both onsite electrical power operation, assuming offsite power is not available, and offsite electrical power operation, assuming onsite power is not available. The system can be fully operated from the main control room.

The evaluation is divided into two phases: (1) full power operation to approximately 100 psig vessel pressure, and (2) approximately 100 psig vessel pressure to cold shutdown (14.7 psia and 200°F) conditions.

15.2.9.3.4.1 Full Power to Approximately 100 psig

Independent of the event that initiated plant shutdown (a normal plant shutdown or a forced plant shutdown) the reactor is normally brought to approximately 100 psig using either the main condenser or, if the main condenser is unavailable, the RCIC/HPCS systems, together with the SRVs.

For evaluation purposes, however, it is assumed that plant shutdown is initiated by a transient event, such as loss of offsite power, which results in reactor isolation and subsequent relief valve actuation and suppression pool heatup. For this postulated condition, the reactor is shutdown and the reactor vessel pressure and temperature are reduced to and maintained at saturated conditions at approximately 100 psig. The reactor vessel is depressurized by manually opening selected SRVs. Reactor vessel makeup water is automatically provided by the RCIC/HPCS systems. The RHR system in suppression pool cooling mode is used to maintain the suppression pool temperature within shutdown limits.

These systems are designed to routinely perform their functions for both normal and forced plant shutdown. Since the RCIC/HPCS and RHR systems are divisionally separated, no single failure, together with the loss of offsite power, is capable of preventing the vessel pressure from reaching the 100 psig level.

15.2.9.3.4.2 Approximately 100 psig to Cold Shutdown

The following assumptions are used for the analyses of the procedures for attaining cold shutdown from a pressure of approximately 100 psig:

(1) The vessel is at 100 psig and saturated conditions;

(2) A worst-case single failure is assumed to have occurred (i.e., loss of a division of emergency power); and

(3) No offsite power is available.

In the event that the RHR shutdown suction line is not available because of single failure, personnel must gain access and attempt to effect repairs. For example, if a single electrical failure caused the suction valve to fail in the closed position, a hand wheel is provided on the valve to allow manual operation. If for some reason the normal shutdown cooling suction line cannot be repaired, the capabilities described below will satisfy the normal shutdown cooling requirements in accordance with GDC 34.

The RHR shutdown cooling line valves are in two divisions (Division 1 = the outboard valve, and Division 2 = the inboard valve) to satisfy containment isolation criteria. For evaluation purposes, the worst-case failure is assumed to be the loss of a division of emergency power, since this also prevents actuation of one shutdown cooling line valve. Engineered safety feature equipment available for accomplishing the shutdown cooling function for the selected path includes:

ADS (DC Division 1 and DC Division 2)

RHR Loop A (Division 1)

HPCS (Division 3)

RCIC (DC Division 1)

LPCS (Division 1)

Since availability or failure of Division 3 equipment does not affect the normal shutdown mode, normal shutdown cooling is available through equipment powered from only Divisions 1 and 2. It should be noted that, conversely, the HPCS system is always available if either of the other two divisions fail. For failure of Division 1 or 2, the following systems are assumed functional:

(1) Division 1 fails, Division 2 and 3 function

Failed Systems	Functional Systems
RHR Loop A	HPCS
LPCS	ADS
	RHR Loops B and C
	RCIC

Assuming the single failure is a failure of Division 1 emergency power, the safety function is accomplished by establishing one of the cooling loops described in Activity C1 of Figure 15.2-12.

(2) Division 2 fails, Division 1 and 3 function

Failed Systems	Functional Systems
RHR Loops B and C	HPCS
	ADS
	RHR Loop A
	RCIC
	LPCS

Assuming the single failure is the failure of Division 2, the safety function is accomplished by establishing one of the cooling loops described by Activity C2 in the notes for Figure 15.2-12.

Using the above assumptions and following the depressurization rate shown in Figure 15.2-13, the suppression pool temperature is shown in Figure 15.2-14.

15.2.9.4 <u>Barrier Performance</u>

This event does not result in any temperature or pressure transient in excess of the design criteria for the fuel, pressure vessel, or containment. Coolant is released to the containment by SRV actuation.

15.2.9.5 Radiological Consequence

The radiological consequences of this event are enveloped by those described in Section 15.2.4.5.

TABLE 15.2-14

SEQUENCE OF EVENTS FOR FAILURE OF RHR SHUTDOWN COOLING

Time	Event
0	Reactor is operating at 102% NBR steam flow when loss of offsite powers occurs initiating plant shutdown.
0	Concurrently loss of Division power (i.e., loss of one diesel generator) occurs.
13 min.	Suppression pool cooling initiated to prevent overheating from SRV actuation.
28 min.	Controlled depressurization initiated (100°F/hr) using selected safety/relief valves.
152 min.	Blowdown to approximately 100 psig completed.
152 min.	Personnel are sent in to open RHR shutdown cooling suction valve; this fails.
157 min.	ADS valves are opened to complete blowdown to suppression pool, and RHR pump discharge is redirected from pool to vessel via LPCI line. Alternate shutdown cooling path has now been established.

TABLE 15.2-15

INPUT PARAMETERS FOR EVALUATION OF FAILURE OF RHR SHUTDOWN COOLING

Initial Conditions

Rated Power (%)		102
Suppression pool mass (lbm)		7.783E6
RHR Hx Constant (Btu/Sec/°F)		390
Vessel pressure (psia)		1040
Vessel temperature (°F)		549.4
Primary coolant inventory (lbm)		4.129E5
Pool temperature, (°F)		100
Service water temperature, (°F)		95
Vessel heat capacity (Btu/lbm/°F)		0.123
HPCS on-off water level (ft)	ON	39.6
	OFF	47.7
HPCS flow rate, (lbm/sec)		673.8
LPCI flow rate per loop (lbm/sec)		715

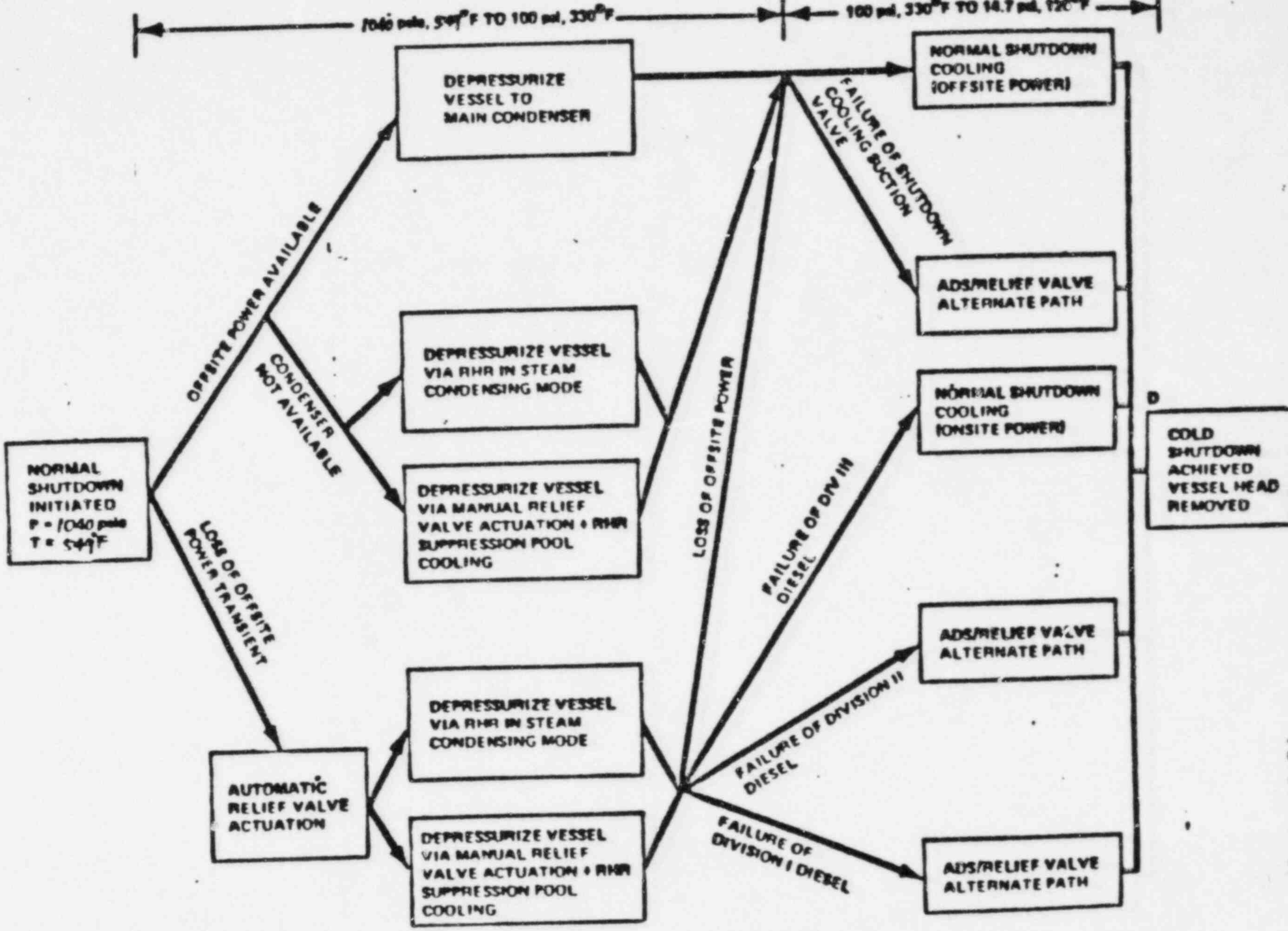


FIGURE 15.2-11 Summary of Paths Available to Achieve Cold Shutdown

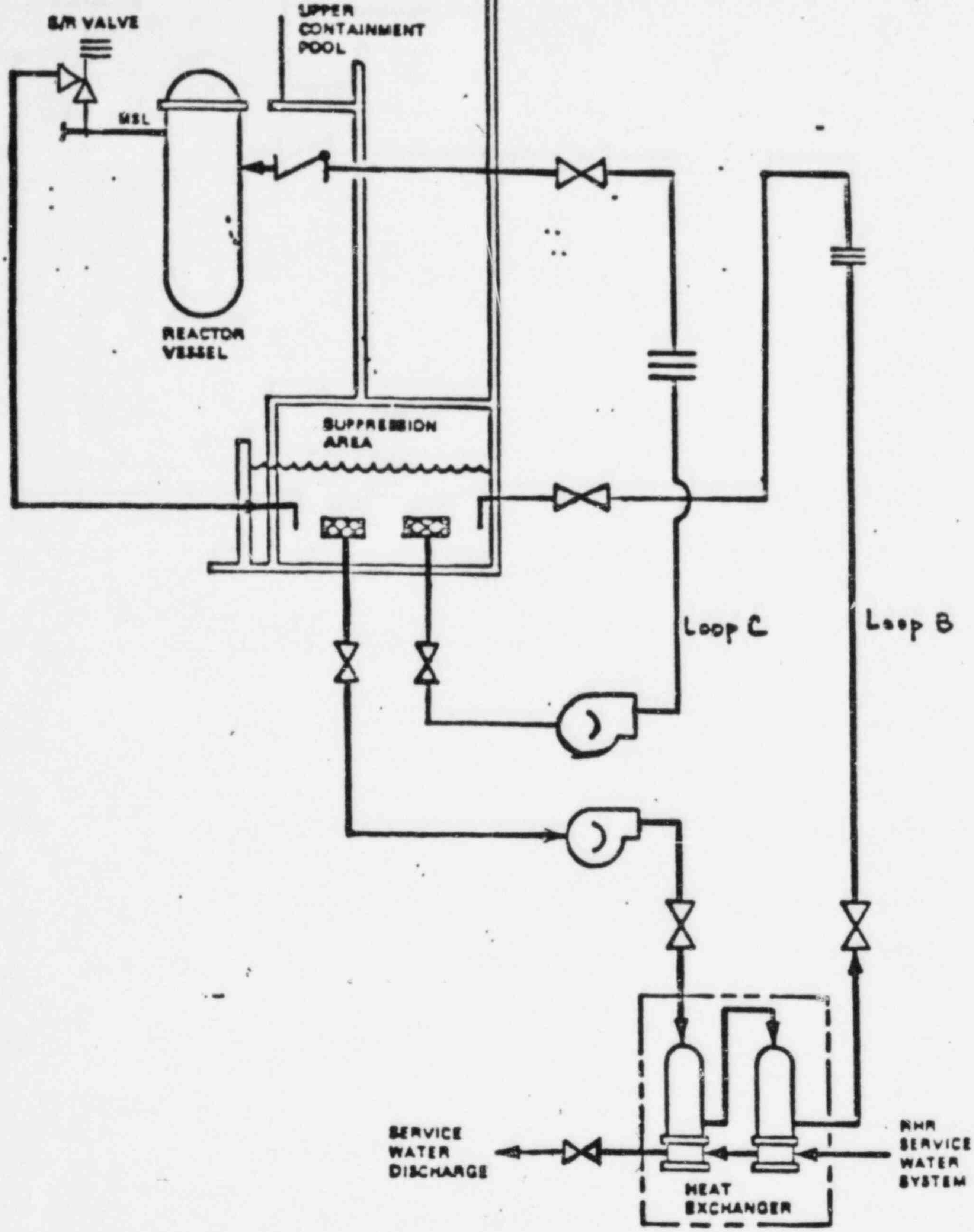


FIGURE 15.2-12 Activity C1 Alternate Shutdown Cooling Path Utilizing RHR Loops B and C

NOTES FOR FIGURE 15.2-12

ACTIVITY A

Initial pressure - 1040 psia
Initial temperature - 549 F

For purposes of this analysis, the following worst-case conditions are assumed to exist:

(1) The reactor is operating at 102% nuclear boiler rated thermal power;

(2) A loss of power transient occurs (see Section 15.2.6); and

(3) A simultaneous loss of onsite power (Division 1), which eventually results in the operator not being able to open one of the RHR shutdown cooling line suction valves.

ACTIVITY B

Initial pressure - 1040 psia
Initial temperature - 549 F

Operator Actions

During approximately the first 13 minutes, reactor decay heat is passed to the suppression pool by the automatic operation of the SRVs. Reactor water level is returned to normal by the automatic operation of HPCS and RCIC.

After approximately 13 minutes, it is assumed on RHR heat exchanger is placed in the suppression pool cooling mode to remove decay heat. At this time, the suppression pool will be 109.5 F. At approximately 28 minutes into the transient, the operator initiates depressurization of the reactor vessel. Controlled depressurization procedures consist of controlling vessel pressures and water level by using selected SRVs, RCIC and HPCS systems.

When the reactor pressure approaches 100 psig, the operator prepares for operation of the RHR system in the shutdown cooling mode. At this time (152 min), the suppression pool temperature is 160.7 F.

ACTIVITY C1 (Division 1 fails, Division 2 available)

System pressure approximately 100 psig
System temperature approximately 340 F

Operator Actions

The operator establishes either one of two closed cooling paths as follows:

NOTES FOR FIGURE 15.2-12 (Continued)

(a) Utilizing RHR Loop B, water from the suppression pool is pumped through the RHR heat exchanger (where a portion of the decay heat is removed) into the reactor vessel. The cooled suppression pool water flows through the vessel (picking up a portion of the decay heat), out the ADS valves, and back to the suppression pool. This alternate cooling path is shown in Figure 15.2-15.

(b) Utilizing RHR Loops B and C together, water is taken from the suppression pool and pumped directly into the reactor vessel. The water passes through the vessel (picking up decay heat) and out the ADS valves returning to the suppression pool as shown in Figure 15.2-12. Suppression pool water is then cooled by the operation of RHR Loop B in the cooling mode as shown in Figure 15.2-12. In this alternate cooling path, RHR Loop C is used for injection and RHR Loop B for cooling. Cold shutdown is achieved approximately 12 hours after the transient occured.

ACTIVITY C2 (Division 2 fails, Division 1 available)

System pressure	approximately 100 psig
System temperature	approximately 340 F

Operator Actions

Utilizing RHR Loop A, as Shown in Figure 15.2-16, instead of Loop B, an alternate cooling path is established as in Activity C1 of item 2(a) above.

FIGURE 15.2-13

RIVER BEND
RPV PRES RESPONSE

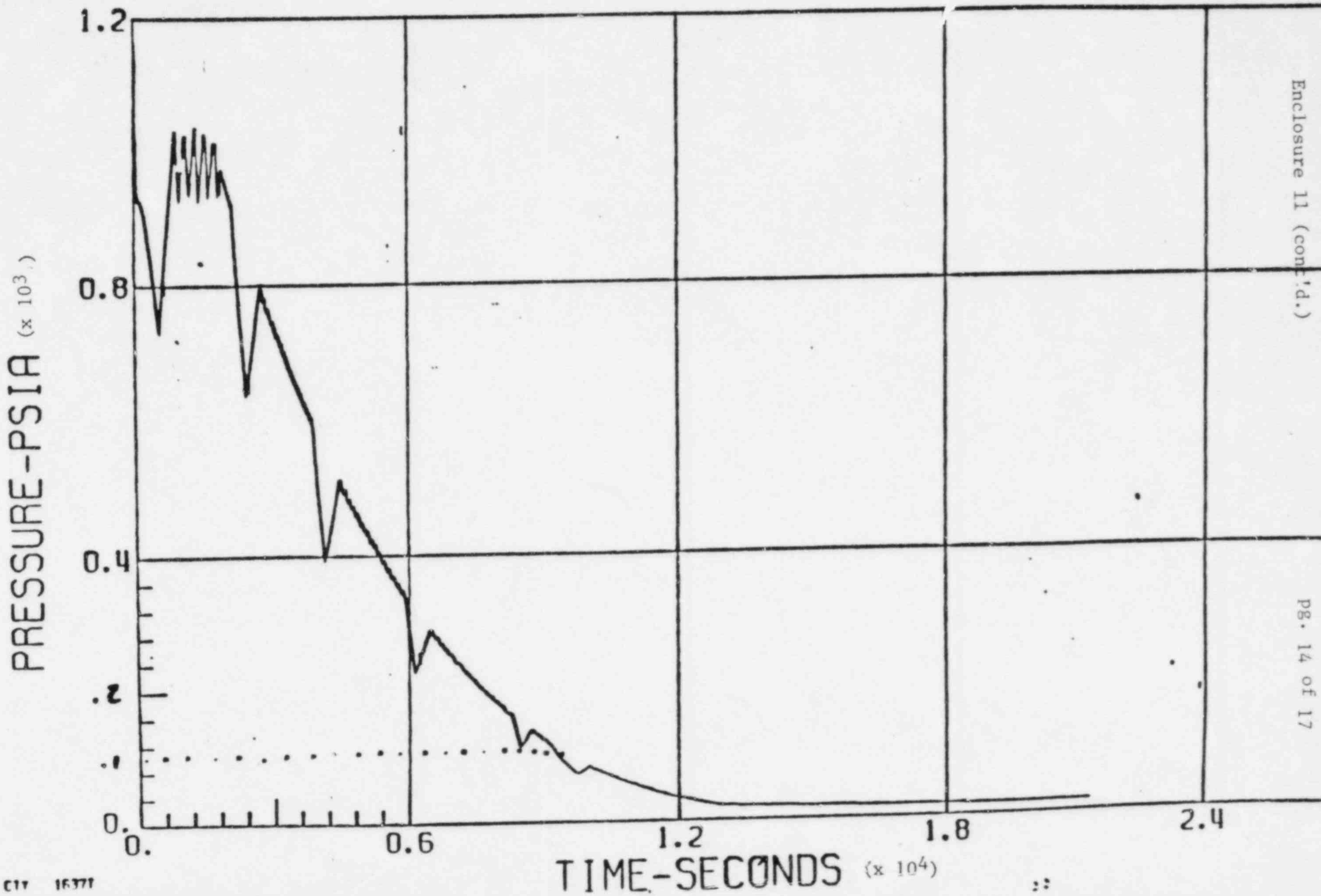
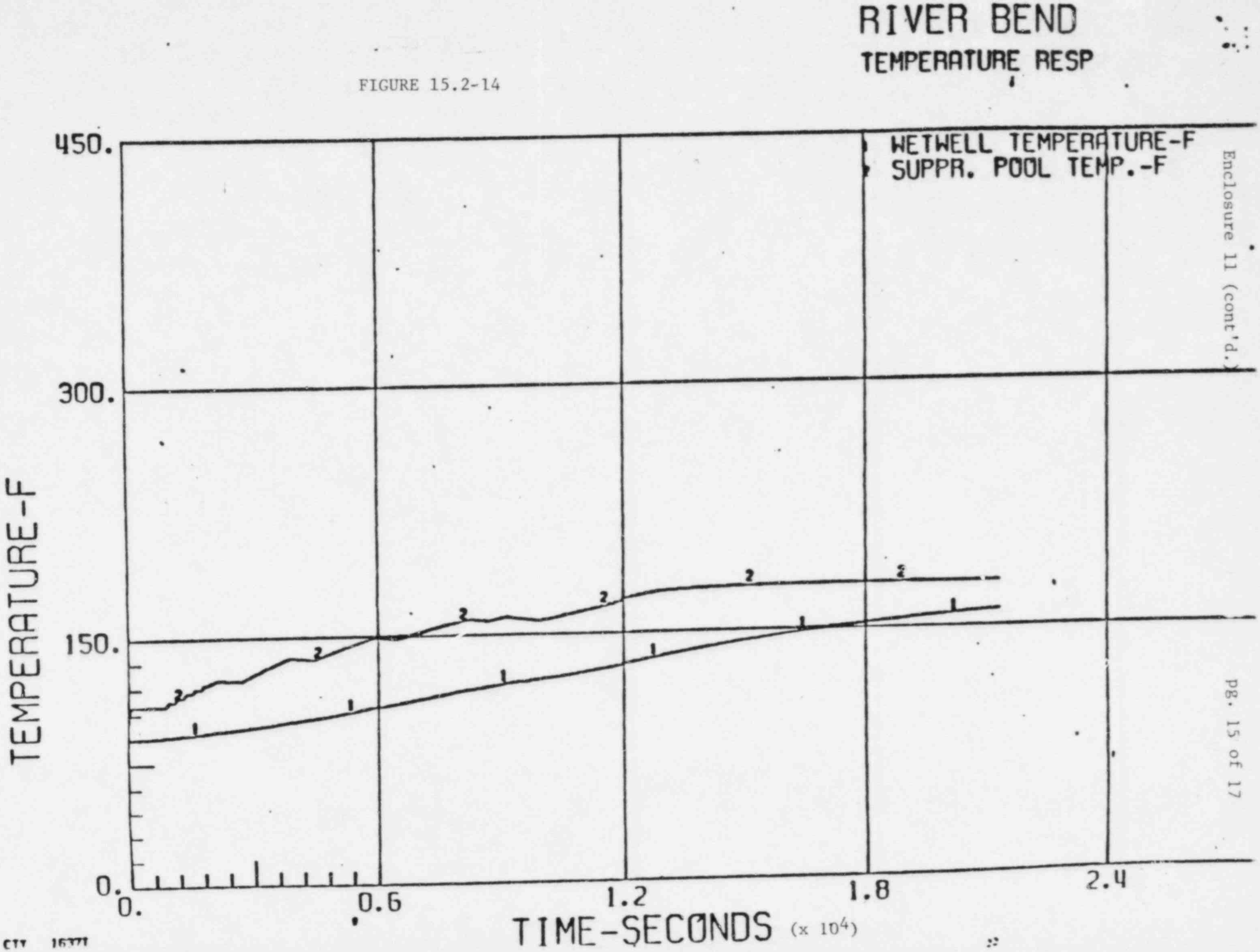


FIGURE 15.2-14



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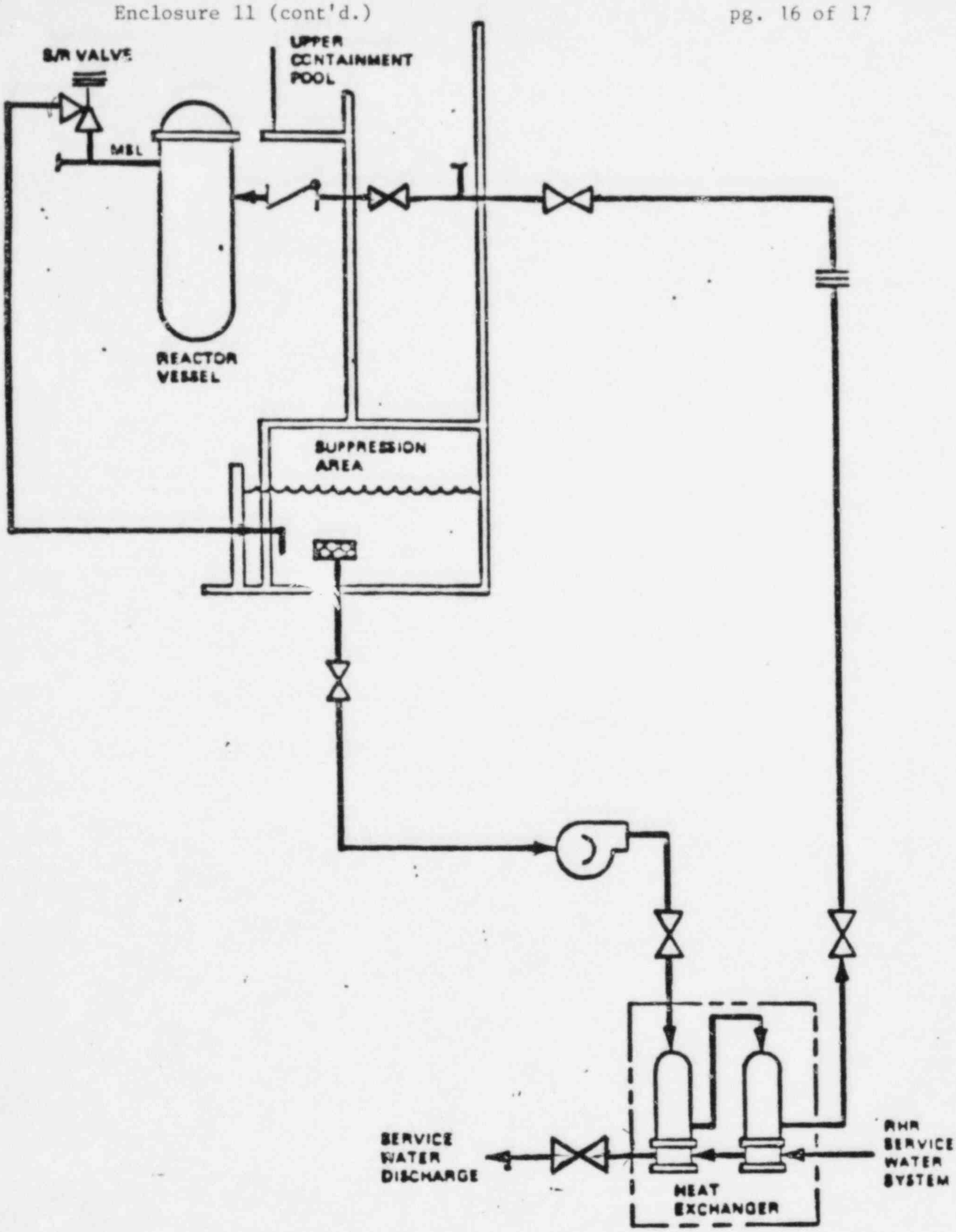

FIGURE 15.2-15 **Activity C1 Alternate Shutdown Cooling Path Utilizing RHR Loop B**

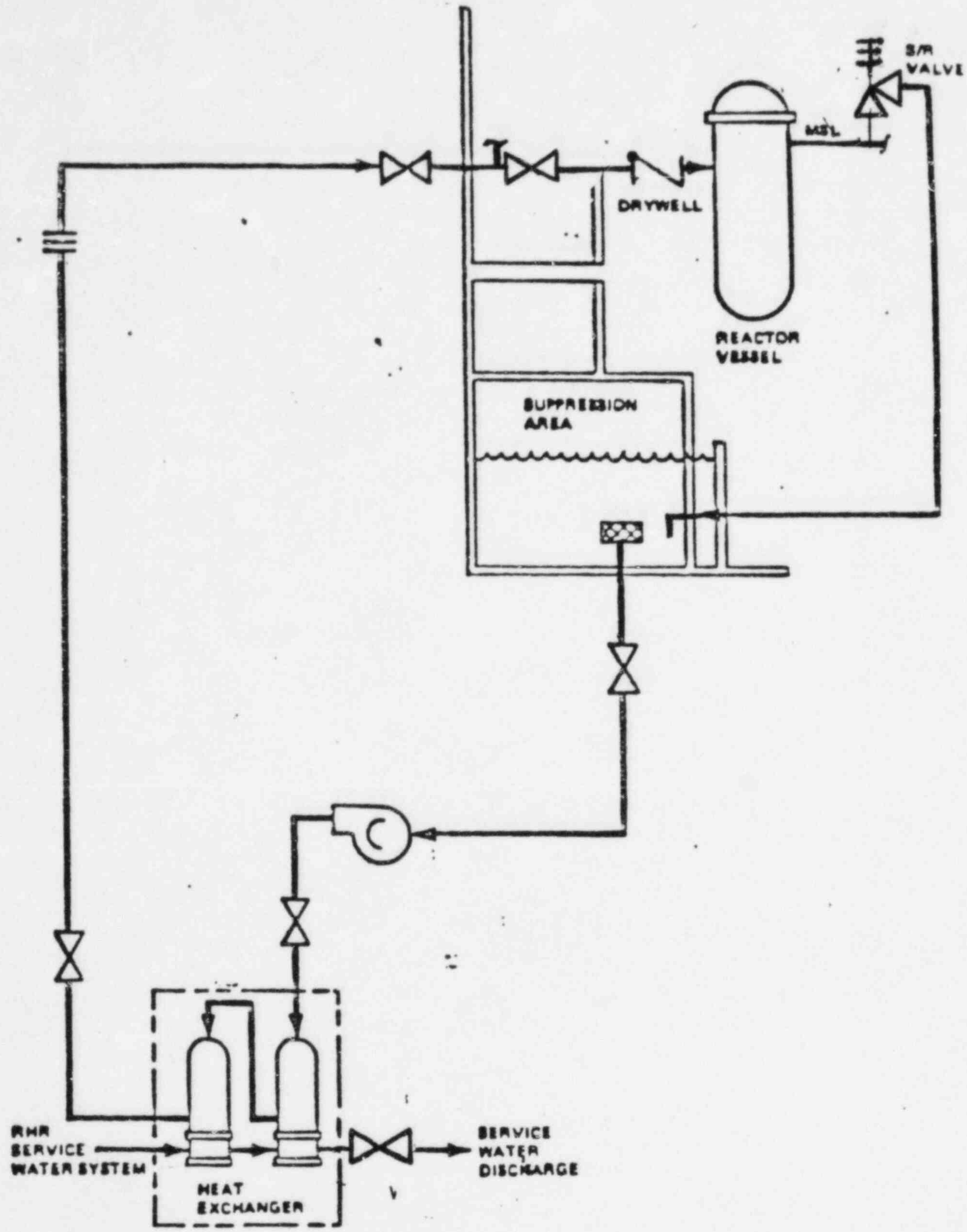

FIGURE 15.2-16 Activity C2 Alternate Shutdown Cooling Path Utilizing RHR Loop A

QUESTION 440.49 (15.1.4)

In the analysis of inadvertent opening of a safety/relief valve, it is stated that a plant shutdown should be initiated if the valve cannot be closed. How much time does the operator have to initiate plant shutdown before exceeding Technical Specification limits for suppression pool temperature?

RESPONSE

~~The response to this request will be provided by November 1982.~~

The operator will have the time period between the valve first sticking open and the bulk pool temperature reaching 100°F before he must scram the reactor to be in compliance with the technical specifications.

The time to reach the 110°F Tech Spec limit is dependent on the initial pool temperature. The pool will heat up at about 2°F/minute. It is assumed that the suppression pool is at its maximum operating temperature (95°F) and minimum operating volume with no pool cooling systems in operation when the valve first opens. The estimated time to reach 110°F is 7 1/2 minutes.

RBS FSAR

QUESTION 440.38 (6.3)

What are the differences between steam line breaks inside and outside containment with regard to break area? The analyses suggest that core uncovery could occur if no operator action took place before 20 minutes. Provide the effect on peak clad temperature of no action prior to 20 minutes and discuss all assumptions (LRG II-issue-4-RSB).

RESPONSE

The response to this request is provided in Sections 6.3.3.2 and 6.3.3.8, and in revised Section 6.3.3.7.7. This analysis requires no operator action prior to 20 minutes to maintain clad temperatures within 10CFR50.46 criteria. This is consistent with LRG-II position 4-RSB.

4. PCT as a function of time from REFLOOD.

The same variables resulting from the analysis of a less limiting small break are shown in Fig. 6.3-53 through 6.3-56.

6.3.3.7.7 Calculations for Other Break Locations

Reactor water level and vessel pressure from SAFE/REFLOOD and PCT and fuel rod convective heat transfer coefficients from REFLOOD are shown in Fig. 6.3-57 through 6.3-60 for the core spray line break, Fig. 6.3-61 through 6.3-64 for the feedwater line break, and Fig. 6.3-65 and 6.3-66 for the main steam line break inside the containment (2.55 sq. ft.).

An analysis was also done for the main steam line break outside the containment (2.66 sq. ft.). Reactor water level and vessel pressure from SAFE/REFLOOD and PCT and fuel rod convective heat transfer coefficients from REFLOOD are shown in Fig. 6.3-67 through 6.3-70.

6.3.3.8 LOCA Analysis Conclusions

Having shown compliance with the applicable acceptance criteria of Section 6.3.3.2, it is concluded that the ECCS will perform its function in an acceptable manner and meet all of the 10CFR50.46 acceptance criteria, given operation at or below the maximum average planar linear heat generation rates in Table 6.3-5.

6.3.4 Tests and Inspections

6.3.4.1 ECCS Performance Tests

All systems of the ECCS are tested for their operational ECCS function during the preoperational and/or startup test program. Each component is tested for power source, range, direction of rotation, set point, limit switch setting, torque switch setting, etc. Each pump is tested for flow capacity for comparison with vendor data. (This test is also used to verify flow measuring capability.) The flow tests involve the same suction and discharge source; i.e., suppression pool or condensate storage tank.

All logic elements are tested individually and then as a system to verify complete system response to emergency signals including the ability of valves to revert to the ECCS alignment from other positions.

QUESTION 440.41 (6.3)

During long-term cooling following a small LOCA, the operator must control primary system pressure to preclude overpressurizing the pressure vessel.

1. Describe the instructions given the operator to perform long-term cooling.

2. Indicate and justify the time frame for performing th required action.

3. List the instrumentation and components needed to perform this action and confirm that these components meet safety grade standards.

4. Discuss the safety concerns during this period and the design margins available

The above discussion should account for the following:

1. Loss of offsite power.

2. Operator error or single failure.

(LRG II issue-4-RSB)

RESPONSE

During long-term cooling following a small LOCA, no operator actions are required to control system pressure to preclude overpressurizing the pressure vessel after it has been cooled off. The system is always protected by relief valve capacity that is more than adequate to handle decay heat energy generation.

QUESTION 440.27

Response to the following TMI action items are required to complete the review of Section 5.4.6.

a) TMI Item II.K.1.22 - Auxiliary Heat Removal. Refer to BWR Owners Group position and submit a plant specific response describing RBS design provisions as given by other BWR Owners.

b) TMI Item II.K.3.13

We request that the applicant submit an acceptable response to the requirements included in Action Plan item II.K.3.13, possible need for separation of RCIC and HPCS initiation levels and restart capability of RCIC on low water level (NUREG-0737).

c) TMI Item II.K.3.15

We request that the applicant submit an acceptable response for Item II.K.3.15, provisions for preventing inadvertent RCIC system isolation or trip.

RESPONSE

7 The response to this request ~~will be provided by June 1983.~~ is provided in Appendix 1A, Table 1A-1, under the items identified above.

TABLE 1A-1 (Cont)

Item and Title	Position	FSAR Reference*
II.K.1.23 Reactor vessel level procedures	The BWR water level instrumentation provides multiple level indications displayed on the reactor control console or nearby panels. These indications include three narrow range (normal operating range) level indicators and one narrow range level recorder, two wide range level recorders and one wide range level indicator, one fuel zone level recorder, one upset range level recorder, and one shutdown range (vessel flooding) level indicator. In addition, multiple indicating trip units provide wide range and narrow range reactor level safety-related trip signals and related alarms. GE has described this in greater detail in NEDO-24708.	7.5
II.K.3.3 Reporting safety valve and relief valve failures and challenges	River Bend Station is currently under construction and therefore a history of safety valve and relief valve failures and challenges for the facility does not exist. Failures of reactor system relief valves will be reported in the appropriate manner to the necessary NRC organizations.	16
II.K.3.11 Justification use of certain PORVs	N/A to RBS	
II.K.3.13 HPCI & RCIC initiating levels	~~The River Bend Station design will be reviewed to determine if reactor safety may be improved by: 1) separating the RCIC system initiation set point from that of the HPCS so that the RCIC initiates at a higher water level than the HPCS, and 2) modifying the RCIC system initiation logic so that the RCIC system will restart automatically on low reactor water level.~~ ~~The BWR Owners' Group is presently performing a generic evaluation of these design modifications. When this evaluation is complete, GSU will review its conclusions and recommendations for applicability to River Bend Station design. Upon completion of this review, recommendations concerning the incorporation of design modifications will be given.~~ INSERT A	7.4

The evaluation performed by General Electric (GE) on behalf of the BWR Owners' Group in a letter transmitted on October 1, 1980, from R. H. Buchholz (GE) to D. G. Eisenhut (NRC) concerning NUREG-0737, II.K.3.13, "HPCI and RCIC Initiating Levels", is applicable to RBS. The report presented the analyses, conclusions, and recommendations regarding separation of the initiating levels of the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) systems. River Bend Station (RBS) does not employ a HPCI system in its GE NSSS design but instead, has a High Pressure Core Spray (HPCS). The report identifies the differences in the HPCI/HPCS thermal fatique analyses where appropriate. In summary, the study concluded that the HPCI and RCIC initiations at the current low water level setpoints is within the design basis thermal fatique analysis of the reactor vessel and its internals. Separating HPCI and RCIC setpoints as a means of reducing thermal cycles is of negligible benefit. In addition, raising the RCIC setpoint or lowering the HPCI setpoint have undesirable consequences which outweigh the benefit of the limited reduction in thermal cycles. Therefore, when evaluated on this basis no change in the RCIC or HPCI/HPCS setpoints is needed.

In a letter dated December 29, 1980, from D. B. Waters, Chairman-BWR Owners' Group, to D. G. Eisenhut (NRC) the BWR Owners' Group transmitted the results of an evaluation performed by GE. The report recommends modifying the RCIC system to automatically restart following a trip of the system at high reactor vessel water level. This will be accomplished by relocating the existing high level trip from the RCIC turbine trip valve to the steam supply valve. Once the level reaches a predetermined high level the steam supply valve will close automatically. GSU endorses the modification to automatically restart the RCIC system on low water level and will incorporate the change in the RBS design. This position is consistent with LRG-II issue 2-RSB(a).

Enclosure 15 (cont'd.) pg. 4 of 7

TABLE 1A-1 (Cont)

Item and Title	Position	FSAR Reference*
II.K.3.15 Isolation of HPCI and RCIC	~~River Bend Station RCIC system design will be reviewed with respect to the desirability of modifying its pipe-break-detection circuitry. The purpose of this review will be to determine if the likelihood of spurious isolation of the RCIC turbine may be reduced. In addition, BWR Owners' Group recommendations based on their generic review and analysis of existing RCIC system designs will be used to formulate a position on the type of modifications (if any) that should be made to the existing RCIC system design.~~	7.4 ← INSERT B
II.K.3.16 Challenges to and failure of relief valves	The BWR Owner's Group position submitted to the Nuclear Regulatory Commission in May 1981 concludes that BWR/6 plants have design features which reduce the occurrence of stuck open relief valve (SORV) events such that no further modifications are required. River Bend Station has already incorporated three design features which should reduce its SORV frequency by at least a factor of 17 compared to the standard BWR/4 plant design. The three features are: 1. Use of Crosby SRVs. 2. Use of a lower reactor pressure vessel water level isolation set point for main steam isolation valve closure. 3. Use of LOW-LOW SET SRV control logic.	5.2
II.K.3.17 ECCS outages	A plan for data collection relating to outage dates and duration for all ECC systems will be developed. These data will be reviewed for availability information on these systems. All ECCS outages will be reported to the NRC via Licensing Event Reports (LER). The report will contain the following: 1. Outage dates and duration of outages. 2. Cause of outage. 3. ECC systems or components involved in the outage. 4. Corrective action taken. The LERs and Nuclear Plant Reliability Data System (NPRDS) will provide the staff with the capability to accumulate, on a yearly basis, reliability data due to test and maintenance outages.	16

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The NUREG-0737 position recommends a modification to the HPCI/RCIC Steam Supply pipe-break-detection circuitry to reduce inadvertent system isolation due to the pressure spike which accompanies startup of the systems. GSU is modifying the existing isolation relay in each detection circuit with a Class 1E time delay relay having a setpoint range from 3 to 13 seconds. The existing circuitry based on continuous high-steam flow closure (trip) of the isolation valves when the flow in that line exceeds approximately 300% of rated flow. The timer starts when the flow meters exceed the trip setpoint. System isolation only occurs if the flow meters still read at or above the trip setpoint at the end of the timer period. It has been determined that the addition of the 3 to 13 second time delay does not result in any change in the total reactor fluid mass release when considering design basis conditions. Therefore, no affect is seen on the design basis analysis. This position is consistent with LRG-II issue 2 RSB(b).

TABLE 1A-1 (Cont)

Item and Title	Position	FSAR Reference*
II.K.3.24 Space cooling for HPCI/RCIC, modifications	The River Bend Station RCIC system is designed to withstand a complete loss of offsite ac power. The RCIC system turbine room space coolers are provided with a backup emergency power supply to ensure that pump room temperatures are maintained below equipment qualification limits during periods when offsite power is unavailable.	5.4.6
II.K.3.25 Power on pump seals	~~The consequences of loss of cooling to the reactor recirculation pump seal coolers will be studied by GE and the BWR Owners' Group. The results and recommendations of the studies will be taken into account to determine if any modifications are necessary.~~ INSERT C	5.4.1
II.K.3.27 Common reference level	GSU has reviewed the BWR Owners' Group generic position on this item and agrees that the current reactor water level instrumentation will provide operators with reactor water level information that will permit the operators to make timely and correct decisions regarding reactor water control requirements. Therefore, no modification of the current main control room water level instrumentation is required on the basis of plant safety considerations.	4.4.6
II.K.3.28 Qualification of ADS accumulators	The BWR Owners' Group is studying, on a generic basis, the ability of the ADS valve accumulators to perform their functions during and following exposure to hostile environments. The results and recommendations of this study will be used to determine if any modifications are necessary.	6.3
II.K.3.30 SB LOCA methods	SBA models used for River Bend Station are found in Chapter 15.6 of the FSAR. Qualification of these models was performed by General Electric (GE) and submitted to the NRC Office of Nuclear Reactor Regulation, on June 26, 1981, from R. H. Bucholz to D. G. Eisenhut. Qualification of the models has been verbally accepted by the NRC.	15.6

7

Gulf States Utilities Company endorses the BWR Owner's Group position submitted to the Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation in letters dated May 26, 1981, September 21, 1981 and September 2, 1982. River Bend Station design employs recirculation pumps manufactured by the Bingham Pump Company. The test simulated a loss of cooling water to the recirculation pump seal coolers which were exposed to a temperature in excess of 270°F. After 5 hours of visually monitoring pump seal leakage, no leakages were detected above 5 gpm. The test results confirmed that a loss of cooling to the Bingham pump seal for 5 hours does not lead to unacceptable seal leakage. Consequently, no change in the River Bend Station design is necessary.

INSERT A

Mechanical separation outside the drywell is achieved as follows:

1. The ECCS is sep[illegible]ted into three functional groups:

   a. HPCS

   b. LPCS + 1 LPCI + 100 percent service water and heat exchanger

   c. 2 LPCI pumps + 100 percent service water and heat exchanger

2. The equipment in each group is separated from that in the other two groups. In addition, the HPCS and reactor core isolation cooling (RCIC) system (which is not part of the ECCS) are physically separated.

3. Separation barriers are constructed between the functional groups as required to assure that environmental disturbances such as fire, pipe rupture, falling objects, etc, affecting one functional group do not affect the remaining groups. In addition, separation barriers are provided as required to assure that such disturbances do not affect both the RCIC and the HPCS.

6.3.1.1.4 ECCS Environmental Design Basis

Each ECCS and the RCIC system have a safety related injection/isolation testable check valve located in piping within the drywell. In addition, the RCIC system has an isolation valve in the drywell portion of its steam supply piping. All valves are located above the highest water level expected in the drywell during any accident. The valves are qualified for the envelope-of-accident environmental conditions indicated in Table 3.11-1.

The portions of ECCS and RCIC piping and equipment located outside the drywell and within the secondary containment are qualified for the envelope-of-accident environmental conditions indicated in Table 3.11-1.

6.3.1.2 Summary Descriptions of ECCS

The ECCS injection network comprises a high pressure core spray (HPCS) system, a low pressure core spray (LPCS) system, and the low pressure coolant injection (LPCI) mode of the residual heat removal (RHR) system. These systems

The RBS design employs an ECCS valve crescent area between the separate watertight ECCS equipment rooms and the suppression pool. The ECCS suction lines and the isolation valves within the cresent area are safety class 2. The systems' design/operating pressures and temperatures are 100 PSIG-212 degrees F/25 PSIG-185 degrees F, and the minimum piping design pressure and temperatures are 235 PSIG-212 degrees F. The valves are designed to preclude leakage and no seals or gaskets are installed between the containment penetrations and the isolation valves.

Each ECCS equipment room is provided with a safety related level transmitter, wall mounted near the floor, to detect a rising water condition which annunciates an alarm and provides level indication in the control room. Also these rooms each contain a sump with a high level alarm and duplex pumps with operating indication in the main control room.

The crescent area contains a sump with high level alarm and duplex pumps with operating indication in the main control room. In addition, periodic surveillance of this area ensures that leakage is detected.

Suppression pool leakage into the ECCS equipment rooms and crescent area can also be detected by safety related suppression pool low level alarms and indications in the main control room.

If leakage is detected by instruments and/or operator surveillance the pump suction isolation valve is remote-manually closed from the main control room. This isolation occurs such that the suppression pool water level does not fall below the minimum allowable vent coverage level.

TABLE 1A-1 (Cont)

Item and Title	Position	FSAR Reference*
	A generic test program which addressed the alternate shutdown mode (two phase and liquid under low pressure conditions) of cooling has been completed. The final test report for the operability test program was submitted in a letter from T.J. Dente (BWR Owners' Group) to D.G. Eisenhut (NRC), dated September 25, 1981. This report, which includes final test data and analyses, demonstrates the operational adequacy of the SRVs and SRV discharge piping and supports. These final test results are contained in the General Electric Co. document NEDE-24988-P, "Analysis of Generic BWR Safety/Relief Valve Operability Test Results" which was included in the September 25, 1981 letter. A review of the test report shows the operational adequacy of the SRVs, discharge piping and supports has been demonstrated for the conditions defined in this TMI Action Plan item. INSERT B	3
II.D.3 Valve position indication	The River Bend Station design includes acoustic sensors which provide a reliable indication of flow in each SRV discharge pipe. An individual indicating light for each SRV, and a common annunciator, are provided in the main control room to indicate when any one of the 16 SRVs is not fully closed. Individual indicating lights are also provided in the main control room for each SRV from the digital signals that actuate the pilot valves that open the associated SRV.	5.2.2.12 7
II.E.4.1 Dedicated hydrogen penetrations	The River Bend Station design includes two redundant hydrogen recombiners inside the containment. Additionally, the containment purge system is designed to satisfy the requirements of this item.	6.2.6.2

This position is consistent with LRG-II issue 6-RSB.

heat exchanger in the redundant portion of the system. A transient analysis indicates that the suppression pool temperature increase is less than 1°F, and the containment pressure increase is less than 0.1 psi. This transient analysis shows that the design objectives of the system can be met following the failure of a single component. No components of the standby service water system are shared between Units 1 and 2. Interconnection of the ultimate heat sink components is discussed in Section 9.2.5.

Large-scale leakage from the standby service water system due to major piping or component failures can be detected by the following methods:

1. Standby service water flows in each redundant header are monitored in the pump discharge and tower return headers and displayed on the standby service water flow recorder. A mismatch in these flows indicates large-scale leakage.

2. Pump discharge header pressure transmitters alarm if the header pressure drops below 85 percent of the required header pressure.

Small-scale leakage from standby service water piping or components can be detected by the following methods:

1. Routine maintenance and inservice inspection

2. Monitoring building and tunnel sump levels

3. Monitoring the operation of components cooled by the standby service water system.

9.2.7.4 Testing and Inspection Requirements

The standby service water pumps are tested at regular intervals to ensure their availability. Isolation valves are also tested on a periodic basis to ensure their operability. The system can be proven operable during refueling shutdown by removing decay heat from reactor core through the residual heat removal (RHR) system heat exchangers.

INSERT C →

9.2.7.5 Instrumentation Requirements

The standby service water supply header pressure in each loop (A and B) is recorded in the main control room. Supply header temperature for each loop is indicated in the main control room. High header temperature and low header

The standby service water pumps (4) for RBS have been identified as deep draft pumps as described in I&E Bulletin 79-15 dated July 1979. The program for assuring long-term operability for these pumps is described below.

Preoperational/Startup Program

As part of the plant startup program, vibration measurements are taken in accordance with the following standard test procedures in order to establish baseline data for comparison to later functional testing and surveillances. Prior to full power operation of the plant each deep draft pump will have experienced a minimum of 100 hours of operation under full system flow and pressure.

Within the first 40 hours of operation in the plant at least 24 hours is continuous operation during which vibration levels are measured every 3 hours (± 30 mins.). Readings are taken during stable operating conditions. All readings taken are recorded. Anomalies in vibration levels are explained. Following the 24 hours continuous running period, and on about the 50th hour and 100th accumulative hour of plant pump running time, vibration measurements are to be repeated. These readings are taken during a period of stable running conditions as near to the 50 hour and 100 hour running time as possible but at least 40 hours apart.

While measuring vibration the following parameters are also measured: bearing temperature, inlet pressure, differential pressure, flow rate, and vibration (peak to peak composite or filtered or unfiltered velocity). Vibration readings are performed per the method described in Section XI paragraph IWP-4500 of the ASME B&PV Code with the allowance for plant-specific relief request. "Alert" and "Required Action" vibration levels are established during this portion of the testing.

Vibration measurements are compared to the acceptable vibration range specified by the vendor. An "alert range" vibration level per ASME Section XI, IWP-3100, is established from an acceptable vibration level with due consideration of sufficient margin to assure that the pump can still perform its safety function when this alert range vibration level is reached; and is maintained as the lower bound "required action" value for the performance of inservice vibration testing. In addition, each of the readings are to be compared for signs of degradation in the pump bearings or for the radial vibration amplitude changes.

Preventive Maintenance Progam

Preventive maintenance and surveillance testing are scheduled at frequent intervals. Scheduled preventive maintenance consists of obtaining megger (resistance) readings of the motor windings, lubricating critical rotating components, plus general cleaning and inspection of rotating electrical equipment at intervals of 3 months to 18 months. Inspection overhaul, alignment, and impeller lift adjustments are scheduled as ISI program test results dictate.

Following pump disassembly and reassembly, the pump is manually turned to assure that there is no major misalignment. Vibration measurements are performed as described below either prior to return to operation or within the Section XI time limit after returning to operation.

Functional Testing and Surveillance

Each deep draft pump is scheduled to be functionally tested in accordance with the time interval specified in Subsection IWP of Section XI of the ASME Boiler and Pressure Vessel Code. Pump inlet pressure differential pressure, flow rate, and vibration are taken. Engineering analyses are performed to identify changes or pump performance trends that may be indicative of off-normal operating conditions. Functional testing and surveillance requirements are specified in Technical Specifications, Surveillance Procedures, and Inservice Inspection Programs.

On a schedule concurrent with in-service tests, as a minimum, vibration levels are measured for these pumps. Prior to performing these measurements, the pump is run continuously until stable bearing temperature conditions are reached. These measurements are performed in the same manner as for the base line data and the same parameters are recorded. Results are compared to the base line data for signs of degradation or radial changes. Values are evaluated, if necessary, to predict pump bearing life.

If vibration levels measured during this period show signs of degradation or reduced bearing life, the cause is determined and corrective action taken as appropriate (i.e., whenever the threshold or "Required Action" values are exceeded.) Following corrective action, vibration levels are measured to determine adequacy of corrective action.

QUESTION 440.36 (6.3)

An electrical interlock is incorporated into the HPCS circuitry that prevents the injection valve from closing automatically upon receipt of the high reactor water level (L8) signals if a high drywell pressure signal still exists. The interlock was added as a result of the NRC staff review of GESSAR-238, which indicated that the interlock was needed to assure diversity of HPCS initiation signals and to prevent premature HPCS termination. However, flooding of the steam lines could result in damage to the safety/relief valves and primary system piping unnecessarily, since the interlock tends to keep the HPCS in operation past the point of reflooding the core and does not significantly add to the overall safety. We require justification for use of the present logic or removal.

RESPONSE

GSU endorses the LRG-II issue 13-RSB which states the electrical interlock will be removed. This modification allows the HPCS flow to be shutoff at high reactor vessel water level (level 8) when a high drywell pressure signal is present and prevents the flooding of the steam lines if the vessel is overfilled. ~~An FSAR amendment will be provided to reflect this modification when the design change is complete.~~

This is reflected in revised Sections 6.3.2.2.1 and 7.3.1.1.1.1 and in revised Figure 7.3-1.

the maximum differential pressure across the valve expected for any system operating mode including HPCS pump shutoff head. The valve opens within 12 sec following receipt of a signal to open provided power is available. This valve is normally closed to back up the inside testable check valve for containment integrity purposes. A test connection/drain line is provided between the two isolation valves and is normally closed with two valves to assure containment integrity.

Remote controls for operating the motor operated components and diesel generator are provided in the main control room. The controls and instrumentation of the HPCS system are described, illustrated, and evaluated in Section 7.3.1.1.

The system is designed to pump water into the reactor vessel over a wide range of pressures. For small breaks that do not result in rapid reactor depressurization, the system maintains reactor water level and depressurizes the vessel. For large breaks the HPCS system cools the core by a spray.

If a LOCA should occur, two signals indicating low water level or high drywell pressure initiate the HPCS and its support equipment. The system can also be placed in operation manually.

The HPCS system is capable of delivering rated flow into the reactor vessel within 27 sec following receipt of an initiation signal.

When a high water level in the reactor vessel is signaled, the HPCS is automatically stopped by a signal to the injection valve to close, ~~unless a high drywell pressure signal exists. If a high drywell pressure signal exists in conjunction with a high reactor water level signal, HPCS injection continues until manually stopped~~. The HPCS system also serves as a backup to the RCIC system in the event the reactor becomes isolated from the main condenser during operation and feedwater flow is lost.

If normal auxiliary power is not available, the HPCS pump motor is supplied by its own diesel generator. The HPCS diesel generator is discussed in Section 8.3.

The HPCS pump head flow characteristics used in LOCA analyses are shown in Fig. 6.3-3. When the system is started, initial flow rate is established by primary system pressure. As vessel pressure decreases, flow increases. When vessel pressure reaches 200 psid (psid = differential pressure between the reactor vessel and the suction source)

The HPCS pump discharge flow and pressure are monitored by pressure switches. If pump discharge pressure is normal but discharge flow is low enough that pump overheating may occur the minimum flow return line valve MO F012 is signaled to open. The valve is automatically closed if flow is normal. The HPCS reaches its design flow rate within 27 sec following receipt of the initiation signal.

If the water level in the condensate storage tank falls below a predetermined level, the suppression pool suction valve MO F015 automatically opens. When MO F015 is fully open the condensate storage tank suction valve MO F001 automatically closes. Two level transmitters are used to detect low water level in the condensate storage tank. Either transmitter can cause automatic suction transfer. The suppression pool suction valve also automatically opens if high water level is detected in the suppression pool. Two level transmitters monitor suppression pool water level and either transmitter can initiate opening of the suppression pool suction valve. To prevent losing suction to the pump, the suction valves are interlocked so that one suction path must be open before the other closes.

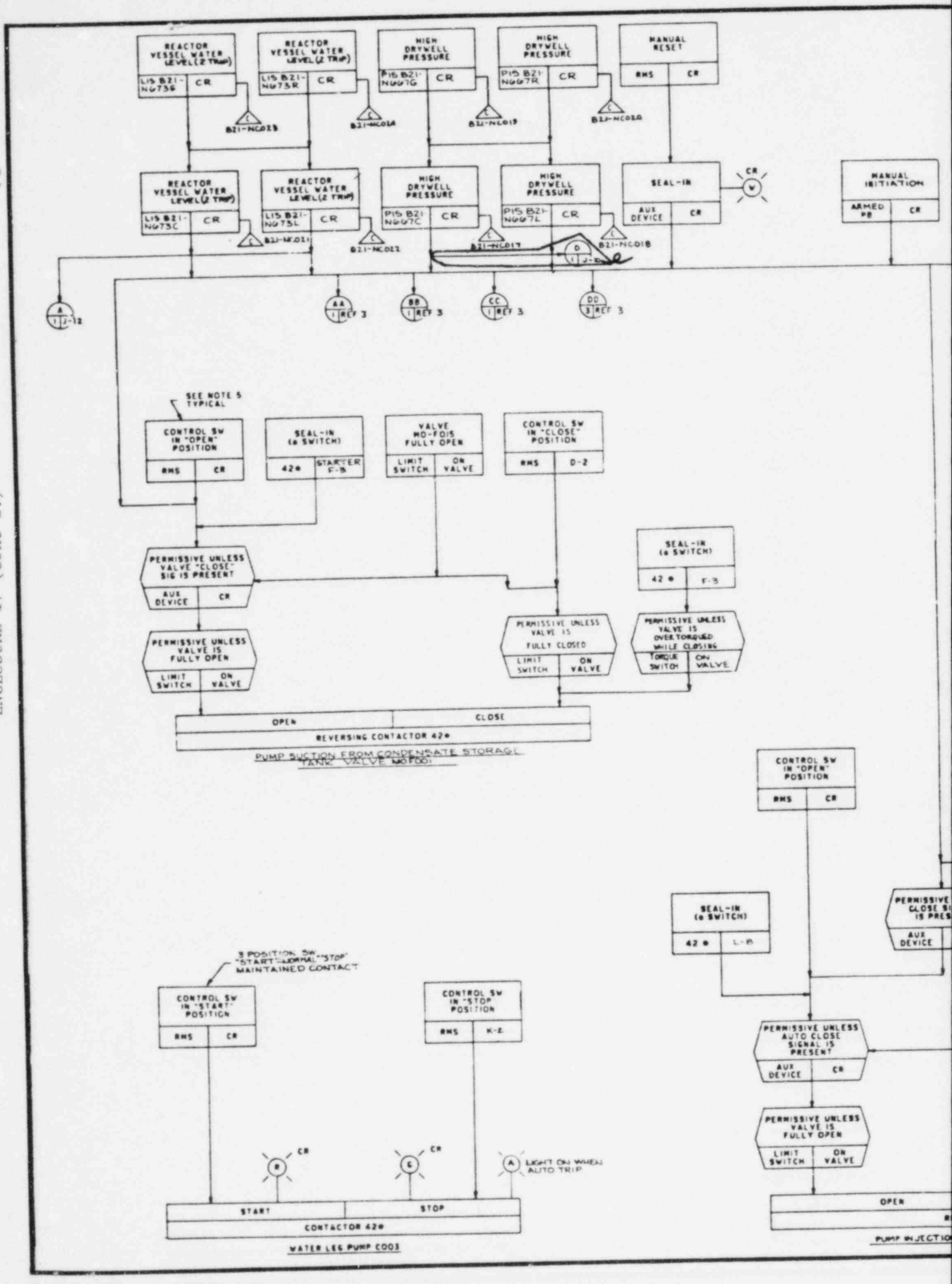
The HPCS provides makeup water to the reactor until the vessel water level reaches the high level trip (trip level 8) ~~and there is no high drywell pressure signal present.~~ The injection valve MOF004 is then automatically closed and the pump continues to run on minimum flow recirculation. The injection valve automatically reopens if vessel level again drops to the low level (trip level 2) initiation point.

The HPCS pump motor and injection valve are provided with manual override controls. These controls permit the reactor operator to control the system manually following automatic initiation.

7.3.1.1.1.2 Automatic Depressurization System (ADS)

1. ADS Function

The ADS is designed to provide automatic depressurization of the reactor vessel by activating seven SRVs. These valves vent steam to the suppression pool in the event that the HPCS cannot maintain the reactor water level following a LOCA. ADS reduces the reactor pressure so that flow from the RHR-LPCI mode and LPCS can inject into the reactor vessel in time to cool the core and limit fuel barrier temperature. Refer also to Section 6.3.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LIS B21-N073G
CR
B21-NC023
REACTOR VESSEL WATER LEVEL (2 TRIP)
LIS B21-N073R
CR
B21-NC024
HIGH DRYWELL PRESSURE
PIS B21-N067G
CR
B21-NC019
HIGH DRYWELL PRESSURE
PIS B21-N067R
CR
B21-NC020
MANUAL RESET
RMS
CR
REACTOR VESSEL WATER LEVEL (2 TRIP)
LIS B21-N073C
CR
B21-NC021
REACTOR VESSEL WATER LEVEL (2 TRIP)
LIS B21-N073L
CR
B21-NC022
HIGH DRYWELL PRESSURE
PIS B21-N067C
CR
B21-NC017
HIGH DRYWELL PRESSURE
PIS B21-N067L
CR
B21-NC018
SEAL-IN
AUX DEVICE
CR
MANUAL INITIATION
ARMED PB
CR
1 REF 3
1 REF 3
1 REF 3
3 REF 3
1 J-12
SEE NOTE 5 TYPICAL
CONTROL SW IN "OPEN" POSITION
RMS
CR
SEAL-IN (a SWITCH)
42●
STARTER F-3
VALVE MO-F015 FULLY OPEN
LIMIT SWITCH
ON VALVE
CONTROL SW IN "CLOSE" POSITION
RMS
D-2
PERMISSIVE UNLESS VALVE "CLOSE" SIG IS PRESENT
AUX DEVICE
CR
SEAL-IN (a SWITCH)
42●
F-3
PERMISSIVE UNLESS VALVE IS FULLY OPEN
LIMIT SWITCH
ON VALVE
PERMISSIVE UNLESS VALVE IS FULLY CLOSED
LIMIT SWITCH
ON VALVE
PERMISSIVE UNLESS VALVE IS OVER TORQUED WHILE CLOSING
TORQUE SWITCH
ON VALVE
OPEN
CLOSE
REVERSING CONTACTOR 42●
PUMP SUCTION FROM CONDENSATE STORAGE TANK VALVE MOF001
CONTROL SW IN "OPEN" POSITION
RMS
CR
SEAL-IN (a SWITCH)
42●
L-8
PERMISSIVE UNLESS AUTO CLOSE SIGNAL IS PRESENT
AUX DEVICE
CR
PERMISSIVE UNLESS VALVE IS FULLY OPEN
LIMIT SWITCH
ON VALVE
OPEN
PUMP INJECTION
3 POSITION SW "START" "NORMAL" "STOP" MAINTAINED CONTACT
CONTROL SW IN "START" POSITION
RMS
CR
CONTROL SW IN "STOP" POSITION
RMS
K-2
LIGHT ON WHEN AUTO TRIP
START
STOP
CONTACTOR 42●
WATER LEG PUMP C003

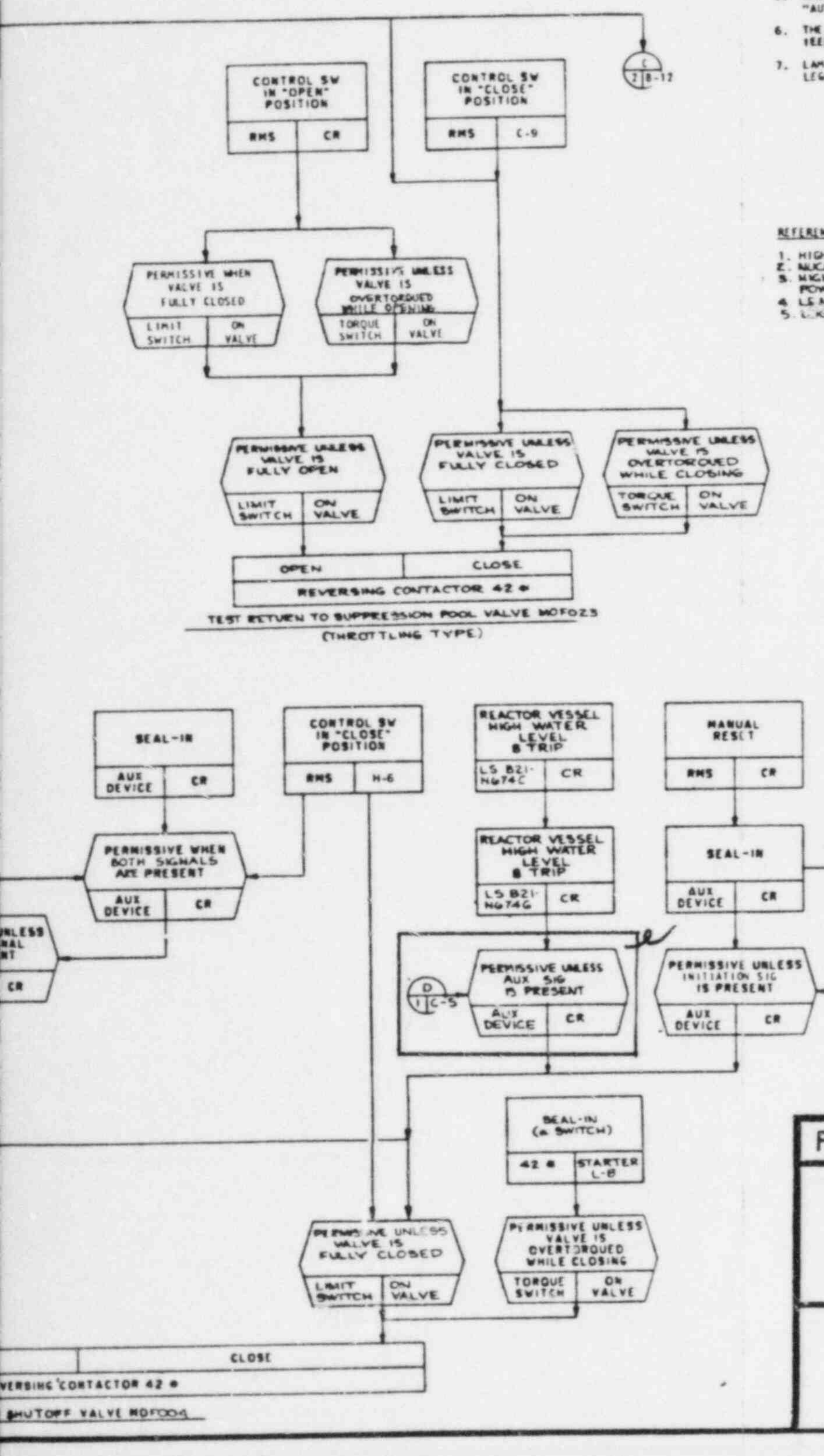
NOTES

1. A) PUMP-MOTOR COMBINATION STARTERS SHALL BE PROVIDED WITH THERMA[L] OVERLOADS WHICH TRIP ON OVERLOAD. BREAKERS SHALL PROVIDE SHO[RT] CIRCUIT PROTECTION. TRIPPING OF EITHER TYPE OF DEVICE IS ANNUNCIATED VIA AN ALARM RELAY.

   B) VALVE MOTORS ARE TO BE PROVIDED WITH THERMAL OVERLOAD TRIPS, LOSS OF POWER ANNUNCIATOR, OVERLOAD TRIPS TO BE BYPASSED UNLESS VALVE UNDER TEST. IN ADDITION VALVE MOTOR CIRCUITS ARE TO BE PROVIDED WITH SHORT CIRCUIT CURRENT PROTECTIVE TRIPS.

2. ALL EQUIPMENT AND INSTRUMENTS ARE PREFIXED BY SYSTEM NUMBER E22 UNLESS OTHERWISE NOTED.
3. FOR ADDITIONAL ALARMS & PROCESS INSTRUMENTATION NOT SHOWN SEE REF. 1.
4. * SWITCHGEAR DEVICE FUNCTION NUMBERS ANSI SPEC C37.2.
5. UNLESS OTHERWISE NOTED ALL RMS SHALL BE 3 POSITION SWITCHES. "CLOSE" "AUTO" - "OPEN" SPRING RETURN TO "AUTO", FROM "CLOSE" - "OPEN".
6. THE HPCS SYSTEM SHALL BE DESIGNED IN ACCORDANCE WITH IEEE279(1971) & IEEE308(1972).
7. LAMPS TO BE PART OF LIGHT BOX LOCATED BELOW REGULAR HPCS ANNUNCIATOR LEGEND AS SHOWN.

REFERENCE DOCUMENTS	MPL ITEM NO.
1. HIGH PRESSURE CORE SPRAY P&ID	E22-101C
2. NUCLEAR BOILER SYSTEM P&ID	B21-1010
3. HIGH PRESSURE CORE SPRAY POWER SUPPLY FCD	E22-1040
4. LEAK DETECTION SYS P&ID	E31-1010
5. LOGIC SYMBOLS	A42-1030



Also Available On Aperture Card

SOURCE-851E892AA, SH. I, REV. I

FIGURE 7.3-1

HIGH PRESSURE CORE SPRAY FUNCTIONAL CONTROL DIAGRAM SHEET 1 OF 3

RIVER BEND STATION

FINAL SAFETY ANALYSIS REPORT

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