AEOD ENGINEERING EVALUATION REPORT

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NSSS/AE:	Several	EVALUATOR/CONTACT: E. J. Brown
SUBJECT:	**A REVIEW OF WATER HAMMER EVENTS AFTER 1985**	
EVENT DATE:	Multiple	

SUMMARY

This study was initiated following several instances of water hammer involving the service water system at Arkansas Nuclear One (ANO). These events were identified during a broad based Diagnostic Evaluation conducted at ANO during August and September 1989. The task was to evaluate the need to reissue previous NRC guidance about water hammer or suggest additional measures.

The water hammer issue was originally addressed as NRC Unresolved Safety Issue (USI) A-1. This USI was considered resolved by publication of NUREG-0927, Revision 1, in March 1984. The staff concluded that new requirements to reduce the number of water hammer events was not supported by cost-benefit guidelines. However, staff provided guidelines concerning measures for water hammer prevention and mitigation in NUREG-0927, Revision 1. A staff reassessment of water hammer was initiated after the San Onofre Unit 1 event in November 1985. The reassessment, completed in 1986, confirmed the original conclusion that new or additional requirements to reduce the number of water hammer events were not supported by cost-benefit guidelines. That reassessment found that the frequency of water hammer events had decreased significantly since the initial review and that there were no new phenomena as causes of water hammer.

A search of the NRC databases identified 12 water hammer events from 1986 through March 1990. Hence, the frequency of reported occurrences continues to drop from that observed during the previous studies. Evaluation of the data led to the conclusion that recent event causes are enveloped by the water hammer phenomena identified during the original USI A-1 investigation. Thus, this re-evaluation supports the prior conclusions that cost-benefit criteria would not support new or additional criteria to reduce the number of water hammer events. However, some aspects identified in the study have not been previously emphasized and they could impact safety. This information should be disseminated to alert licensees. These items

are: (1) some water hammer events were the result of failure to implement the guidance issued in the resolution to USI A-1, (2) hydrodynamic interactions between systems may occur, (3) system realignments can involve complex issues concerning component operability as well as water hammer, and (4) RHR pump maneuvering in BWR plants has resulted in many isolation valve closures followed by loss of shutdown cooling and a few water hammer events.

Based on these four items, the evaluation concludes that an information notice describing these items would be useful. A draft Information Notice is provided in Appendix B to this report. In addition, the report suggests that investigation of the many events (more than 20) involving closure of isolation valves when attempting to use BWR shutdown cooling should be included as part of the NRR Plan for Evaluating Safety Risk During Shutdown and Low Power Operation.

DISCUSSION

A broad based Diagnostic Evaluation was conducted at Arkansas Nuclear One (ANO) during August and September 1989 (Ref. 1). The Staff Actions Memorandum (Ref. 2) of December 21, 1989, identified several instances of water hammer involving the service water system. The action assigned was to review and determine the extent of industry water hammer events that occurred since the issuance of NUREG-0927, Revision 1, "Evaluation of Water Hammer Occurrence In Nuclear Power Plants," in March 1984, and evaluate the need to reissue the NUREG or suggest additional measures.

The water hammer issue was originally addressed as Unresolved Safety Issue A-1. The issue was considered resolved by publication of NUREG-0927, Revision 1, in March 1984. The staff concluded that the frequency and severity of water hammer events had been reduced through (a) incorporation of design features such as keep fill systems, vacuum breakers, steam generator J-tubes, void detection systems and improved venting systems, (b) proper design of feedwater valves and control systems, and (c) increased operator training. Thus, cost-benefit guidelines did not support a need for new requirements to reduce the number of water hammer events. The resolution of USI A-1 involved preparation of revisions to a few specific sections of the Standard Review Plan (SRP) that would apply to all plants docketed after these revised SRPs were issued. It was also concluded that total elimination of water hammer was not feasible.

The water hammer issue was reassessed following the water hammer event at San Onofre Unit 1 on November 21, 1985. The reassessment results were reported in a memorandum from H. R. Denton to V. Stello dated July 7, 1986 (Ref. 3). It was concluded that the reassessment confirmed the original conclusion in that new or additional requirements intended to reduce water hammer events were not supported by cost benefit guidelines. This conclusion was based on the significant reduction in frequency of water hammer events that had occurred in the 1981 to 1985 time frame relative to the previous decade's experience, that

the events did not involve systems which had not been previously identified, and that event causes were the same as those indicated in USI A-1 (e.g., no new phenomena had been identified).

The Initial USI A-1 assessment involved review of 148 reported events from 1969 to 1980 while the reassessment after the San Onofre event reviewed 40 events from 1981 to 1985. A search of NRC databases for the time frame from 1986 through March 1990 using the key words "water hammer" identified 12 event reports with this phrase in the text. Since some events involved other hydraulic phenomena, the phrase "water hammer/hydrodynamic loads" is used in this report for these 12 events. As a result of the concerns identified in Refs. 1 and 2, these 12 events were the basis for an independent review of water hammer events.

Each event was reviewed to determine the nature of the event and assess whether it was associated with new physical phenomena. The review also concentrated on identification of common mode aspects and lessons that may be useful to assist other plants in prevention of situations that could result in water hammer. A summary of each event is provided for information in Appendix A. Table 1 is a list of these recent events which includes the plant name, data source, affected system, and a brief event description.

TABLE 1. WATER HAMMER EVENTS AFTER 1985

Plant/Data Source LER or Other Report	System	Event Description
Susquehanna 2 388/86-015-01	RHR Shutdown Cooling Mode	Valve isolation while switching from Pump D to Pump A. Partial pipe draindown not refilled prior to restart.
Sharon Harris 400/87-029-01	Steam Generator Blowdown	Rapid motion of isolation valve resulted in snubber damage.
Trojan 344/87-013-01	Accumulator Fill Lines	Transferring water between accumulators with high differential pressure. No procedure.
South Texas 1 498/87-016-01	AFW Vent Lines	Pressure fluctuations developed by crossover flow control valve throttling.
Indian Point 3 286/88-002	Feedwater	Cycling a flow control valve (FCV) caused pressure drop between FCV and isolation valve.

TABLE 1. WATER HAMMER EVENTS AFTER 1985 (Continued)

Plant/Data Source LER or Other Report	System	Event Description
Oyster Creek 219/88-021	Isolation Condenser (IC)	Steam lines to IC partially filled with water. Suspected reverse flow through one-half of each IC.
Waterford 3 382/89-015	Steam Generator Blowdown	Cycled inside containment isolation valve to verify operability without closing outside isolation valve.
Oconee 3 287/89-002	Main Steam	Suspected water accumulation in a drain line for the turbine bypass line to the A condenser.
Palisades 255/90-14 (Inspection Report)	Accumulator Injection	Safety injection tank vented to 50 psig and back leakage from primary system.
ANO 2 368/88-023	Steam Supply to AFW	Condensate buildup at a lowpoint resulted in water slugging on EFW pump startup.
Dresden 2, 3 237/89-029-01	High Pressure Coolant Injection (HPCI)	Leaking HPCI injection valve and check valve caused FW leakage into HPCI system and void formation.
Dresden 2 237/89-029-01	HPCI	FW leakage into HPCI system due to MOV failure to completely close after IST stroke timing test.

SYNOPSIS

From the information in Table 1 and Appendix A, it is evident that the water hammer events reported to NRC from 1986 to the present have occurred in both BWR and PWR plants. The BWR plant systems involved are the shutdown cooling mode of RHR, the isolation condenser, and HPCI. These BWR systems have all been identified with water hammer events in previous studies. The PWR plant systems are main steam, AFW steam supply, steam generator blowdown, feedwater, accumulator (fill lines and injection to the reactor coolant system), and the AFW system ventlines. Most of these PWR systems have been associated

with water hammer in previous studies. Although some specific aspects such as the accumulator fill lines and injection line and the AFW ventlines appear to be different areas, the physical phenomena involved steam void formation and fluid flow between high and low pressure systems which are likely candidates for water hammer.

Even though these recent events are comparable and consistent with those reviewed in previous studies, some of the events exhibit system interaction characteristics that were not emphasized in previous studies. For example, the event at South Texas was initially believed to be only water hammer-related. Subsequent evaluation determined that control valve throttle position could introduce pressure fluctuations that eventually matched one of the piping system acoustic natural frequencies. This condition subsequently resulted in pipe rupture. Also, the closure of shutdown cooling isolation valves has been identified with fluid system interactions that appear to perturb monitored parameters resulting in undesired isolation signals. Shutdown cooling will be lost and water hammer may result if realignment procedures are not adequate. This phenomenon does not seem to be well understood because several BWR plants have experienced this problem and have attempted different solutions with varying degrees of success.

The recent water hammer events seem related to lack of implementation of the guidance issued in the resolution to USI A-1 (NUREG-0927, Revision 1). For instance, some causes cited were failure to fill and vent properly, rapid valve stroking, lack of guidance about system configuration, low point water accumulation, depressurization of a system which could cause local flashing, and bypassing steam traps. Thus, water hammer can result when plant staff are not vigilant concerning system conditions and changes in system arrangement.

The events at Trojan (LER 344/87-013-01) and Dresden 2 and 3 (LER 237/89-029-01) illustrate this situation. They involved system alignment changes in which the significance may not have been fully appreciated. At Trojan, there was an attempt to transfer water to accumulator "D" from accumulator "A" via the fill lines for each accumulator because the sample lines, which had procedures for such application, were tagged out for maintenance. There were no procedures for transferring water between accumulators by use of the fill lines. There were two attempts at water transfer, and two pipe ruptures, utilizing an approach that had not been reviewed for systems with a pressure differential of several hundred pounds per square inch. Thus, the need to fill the accumulator led to using an unauthorized approach without appropriate checks to satisfy safety considerations.

The series of water hammer events in the HPCI system at Dresden Units 2 and 3 were all related to known continued leaking of isolation valves during plant operation. Plant operation with the leaking valves (a check valve between the feedwater and HPCI system* and the normally closed HPCI isolation or injection valve) was initially attempted by utilizing monitoring techniques intended to identify undesirable system temperature conditions.

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* Refer to Appendix A, Section A.11 and Figures A4, A5, and A6 for additional description and system configuration.

Subsequent efforts involved both monitoring and realignment of system motor operated valves. Water hammer events occurred in each instance. Simple monitoring was inadequate because temperatures could increase to a condition in which local steam voids formed and subsequent water hammer could occur. HPCI system valve realignment (Dresden Unit 2) involved closing the normally open outboard isolation valve so that it then became the injection valve, opening the normally closed inboard isolation valve, and closing the condensate storage tank return valve so it became a pressure isolation valve. This valve realignment had several features of interest. These features are (1) assurance of MOV operability against full differential pressure (~ 1200 psi), (2) relationship between the new alignment and valve position changes required for MOV tests such as inservice tests, and (3) MOV control features such as signal seal-in or torque switch bypass aspects.

At Dresden, the normally closed HPCI injection valve (which leaked) was evaluated for operation against full differential pressure (1135 psi) as a result of IE Bulletin 85-03, "Motor Operated Valve Common Mode Failure During Plant Transients Due to Improper Switch Settings," issued November 15, 1985. However, the MOVs utilized in the realigned configuration (HPCI normally open isolation valve and condensate return valve) were not evaluated for operation against high differential pressures until NRC Bulletin 85-03, Supplement 1, was issued to address motor-operated valve inadvertent operation (closure or opening due to mispositioning) on April 27, 1988. Thus, a system realignment prior to April 1988 could have resulted in placing MOVs in a configuration for which operability requirements may not have been adequately addressed (other system realignments should review this aspect carefully). Plant Technical Specifications still required MOV stroke tests and HPCI system flow tests as part of the inservice test (IST) program. In order to conduct these tests, it was necessary to temporarily utilize the previously leaking valves as isolation valves against the feedwater system pressure.

This aspect, in conjunction with the condensate return valve that did not have a seal-in feature for the closure signal (the valve was 25% open when the control panel light indicated closed*) eventually led to formation of local voids and water hammer in the HPCI system. Therefore, a relatively simple realignment of MOVs to provide HPCI injection evolved into a complex situation that required detailed knowledge of subcomponent control features and settings and system (component) operational requirements (including IST tests) in order to protect the HPCI system from potential damaging water hammer events as well as assurance for injection capability.

FINDINGS

Evaluation of the data identified from the search for water hammer events for 1986 through March 1990, resulted in findings as follows:

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* The control room light indicated closed because of the MOV control features which used the same limit switch to set the open torque switch by-pass and the closing light indication (this approach may still be used in several plants).

1. There were 12 water hammer events identified from 1986 through March 1990. This indicates the event frequency is dropping compared with previous studies (148 events from 1969 to 1980 and 40 events from 1981 to 1985).

2. The causes of the 12 recent water hammer events reviewed in this study were similar to causes identified in previous studies. Thus, there were no new phenomena identified.

3. The new water hammer events appear related to either a failure to implement the guidance issued in the resolution to USI A-1 (NUREG-0927, Revision 1); a less than vigilant attitude concerning system conditions, operations, or changes in system alignments that could result in water hammer; or an insufficient understanding of system conditions, including component operational characteristics, that could cause water hammer.

4. The cited water hammer event causes included failure to fill and vent properly, too rapid valve stroking, lack of guidance about system configuration, water accumulation at low points, depressurization of a system which could lead to local flashing, and bypassing steam traps.

5. Some water hammer events indicate hydrodynamic interaction between systems may occur.

6. System realignments involving MOVs may involve very complex issues that could affect component operability or possibly result in water hammer events.

7. Many events were identified that involved closure of the letdown isolation valve during attempts to use the shutdown cooling mode of RHR in BWR plants. Closure of the isolation valve results in pump trip and loss of shutdown cooling. A few of the events also involved water hammer.

CONCLUSIONS

The assessment process for USI A-1 was based on a disciplined approach of review of each event which resulted in identification of affected systems, determination of event frequency, and establishing the phenomena that caused the water hammer. Based on the evaluation in this study, it was found that the 12 recent water hammer events represent a reduction in frequency of occurrence at operating plants and that no new physical phenomena were identified as causes of water hammer. Therefore, the recent operating experience is not inconsistent with the resolution conclusions for both USI A-1 and the subsequent reassessment after the San Onofre event in 1985. Thus, there does not appear to be a need to reissue NUREG-0927, Revision 1.

Although these recent water hammer events are comparable with those reviewed in previous studies, there are some aspects that were not previously emphasized which have an impact on safety so they warrant dissemination to alert all licensees. The specific areas include (1) failure to implement the guidance issued in the resolution to USI A-1, (2) hydrodynamic interaction between systems, (3) system realignments involving MOVs that may involve complex issues concerning component operability as well as water hammer, and (4) closure of letdown isolation valves in the shutdown cooling mode of RHR for BWR plants. The first three areas were clearly evident in the water har ier events reviewed in this study. The fourth area did result in a few water hammer events. However, closure of the isolation valve will result in loss of shutdown cooling. Thus, it appears there are two distinct issues. It was concluded that dissemination of information about recent water hammer events would have benefit for licensees. First, it would serve to remind plant staff about the need to implement the guidance developed in USI A-1 relative to measures useful for prevention and mitigation of water hammer. In addition, it would identify the hydrodynamic interactions between systems and system realignment issues that have not been emphasized previously. Therefore, a proposed Information Notice to address the water hammer/hydrodynamic load aspects is provided in Appendix B.

Although closure of the letdown isolation valve for BWR plant shutdown cooling may lead to water hammer, which is addressed in the proposed Information Notice, it has other safety aspects because it leads to loss of shutdown cooling. Because many events (more than 20) were identified, it is suggested that closure of the shutdown cooling isolation valve should be included as part of the NRR Plan for Evaluating Risk During Shutdown and Low Power Operation.

REFERENCES:

1. U.S. Nuclear Regulatory Commissi , "Diagnostic Evaluation Team Report for the Arkansas Nuclear One Units 1 and 2," December 1989.

2. U.S. Nuclear Regulatory Commission, J. M. Taylor to T. E. Murley, et al., "Staff Actions Resulting From the Diagnostic Evaluation at Arkansas Nuclear One," December 21, 1989.

3. U.S. Nuclear Regulatory Commission, H. R. Denton to V. Stello, Jr., "Review and Assessment of Water Hammer Occurrences Since CY 1981," July 7, 1986.

4. LER 388/86-015-01, "Primary Containment Isolation Valve Closes Twice Due to a Spurious High Flow Signal," December 18, 1986, Susquehanna Unit 2.

5. LER 400/87-029-01, "Steam Generator Blowdown Piping Snubber Inoperable," July 31, 1987, Sharon Harris Unit 1.

6. LER 344/87-013-01, "Accumulator Fill Line Rupture Due to Backflow Induced Vibration," July 10, 1987, Trojan.

7. LER 498/87-016-01, "Hydraulic Transients in the Auxiliary Feedwater System Due to Design Error," March 15, 1988, South Texas Unit 1.

8. South Texas Project, "Auxiliary Feedwater System Report - Investigation of Hydraulic Transient Events," ST-HL-AE-2461, December 1987.

9. South Texas Project, "Auxiliary Feedwater Hydraulic Transient - Supplemental Report," ST-HL-AE-2516, February 19, 1988.

10. LER 286/88-00[illegible], "Reactor Trip, Main Boiler Feed Pump Trip Due to Main Boiler Feed Pump Discharge, Valve Limit Switch Actuation Caused by Water Hammer Induced Vibration," April 21, 1988, Indian Point Unit 3.

11. LER 219/88-021, "Plant Shutdown Due to Both Isolation Condensers Being in an Unanalyzed Condition Due to Thermo-Hydraulic Operation Outside Normal System Design," October 26, 1988, Oyster Creek.

12. LER 382/89-015, "Containment Isolation Valve Inoperable Due to Inadequate Design and Inadequate Procedure," August 28, 1989, Waterford 3.

13. LER 287/89-002, "Reactor Trip Due to Turbine/Generator Trip," April 5, 1989, Oconee Unit 3.

14. U.S. NRC Inspection Report 255/90-14, June 13, 1990 for Palisades.

15. LER 368/88-023, "Mechanical Snubber Failure on One Train of the Emergency Feedwater System Due to Water Entrainment in Steam Piping Results in Operation Prohibited by Technical Specifications," June 1, 1989, Arkansas Nuclear One Unit 2.

16. LER 237/89-029-01, "Elevated HPCI Discharge Piping Temperature Due to Reactor feedwater System Back Leakage," May 1, 1990, Dresden Units 2 and 3.

APPENDIX A

Summary of Water Hammer/Hydrodynamic Load Events Since 1985.

A.1 Susquehanna Unit 2, LER 388/86-015-01 (Ref. 4)

On October 12, 1986 Unit 2 was in the shutdown cooling mode, condition four, with the "D" residual heat removal (RHR) pump in service. With the "D" pump running, the "B" RHR pump was then started (See Figure A1). The switchover to the "B" pump in service was completed with shutdown of the "D" pump. However, at approximately the same time, closure of the outboard isolation valve (F008) occurred in the letdown line from the "B" recirculation loop to the suction of the "B" RHR pump. Closure of the suction valve caused the "B" RHR pump to trip. Operations personnel reset the logic and reopened the F008 valve. Opening the F008 valve resulted in water hammer and the F008 valve again closed. The water hammer was due to partial draindown of the system through a pathway to the condenser. This pathway was present to control reactor water level while the RHR system was in service. The operators failed to fill and vent the system piping after the "B" RHR pump tripped.

A.2 Shearon Harris Unit 1, LER 400/87-029-01 (Ref. 5)

A damaged snubber was discovered on steam generator 1A blowdown system piping on April 22, 1987. In addition, two broken pipe supports and obvious pipe displacement were observed. The steam generator blowdown piping is safety-related because of concerns of high energy pipe breaks outside the reactor containment. The cause of water hammer was attributed to rapid motion of the blowdown isolation valve. The corrective action was to increase the stroke time of the isolation valve.

A.3 Trojan, LER 344/87-013-01 (Ref. 6)

On May 12, 1987, the "A" accumulator one-inch fill line ruptured at the nozzle to pipe weld while transferring water from the "A" accumulator to the "D" accumulator. Approximately 2000 gallons of water were released to the containment. The "A" accumulator was at 583 psig and the "D" accumulator was depressurized. Failure was due to low cycle, high stress fatigue cracking. After repair, the pipe again ruptured when water transfer through the fill lines was attempted with the "A" accumulator at 650 psig and the "D" accumulator depressurized. Excessive reverse flow through the packless diaphragm globe valve caused cyclic vibration. Procedures were in place to transfer water between accumulators via the sample lines, but there were no procedures for water transfer via the fill lines. Water was transferred between the accumulators via the fill lines because the sample lines were tagged out for maintenance. A dynamic analysis which modelled backflow through the fill line showed that hydraulic loads far in excess of those necessary to fail the pipe would be imposed on the nozzle-to-pipe weld. Also, a backflow test through a packless globe valve similar to

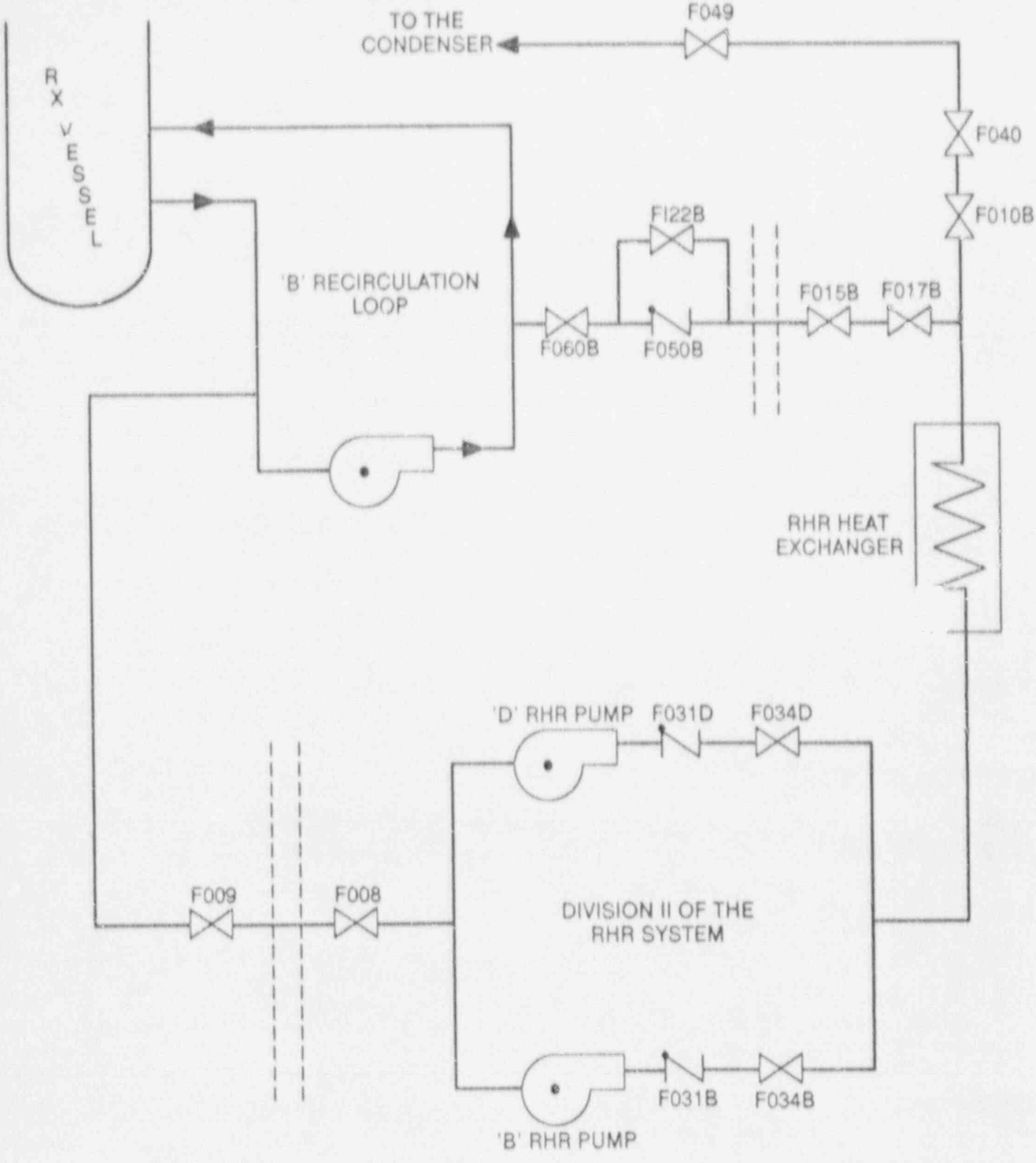

FIGURE A1.
RHR SHUTDOWN COOLING FOR SUSQUEHANNA UNIT 2

the valve in the accumulator fill line resulted in a pipe failure at a flow of about 70 gpm. Operating procedures were revised to prohibit water transfer between the accumulators.

A.4 South Texas Unit 1, LER 498/87-016-01 (Ref. 7)

On November 5,1987, while in mode 4, prior to initial criticality, a one inch double valve vent line in the pump discharge piping of the auxiliary feedwater (AFW) train "A" broke off. A second failure occurred three days later in a similar manner in a double valve instrument tap for the train "D" AFW pump discharge line (See Figure A2). The initial assessment cited the cause as water hammer resulting from improper venting of the system. The AFW system continued to experience vibration. Subsequent testing identified that flow control valves in Trains "A" and "D" introduced a pressure fluctuation when they were in a highly throttled position. The dominant pressure fluctuation frequency of 24 Hz matched one of the piping system acoustic natural frequencies. Mechanical stops were installed to prohibit excessive throttling of the valves. Resolution of this issue involve an extensive test program and special reports ST-HL-AE-2461 (Ref. 8) and ST-HL-AE-2516 (Ref. 9) were issued.

A.5 Indian Point Unit 3, LER 286/88-002 (Ref. 10)

On March 31, 1988, the main boiler feedwater pump (MBFP) No. 32 tripped with the reactor at 100% power. The pump tripped in response to a "discharge valve not fully open" signal. This signal was generated by motion of the discharge valve (BFD-2-32) non-rotor-driven limit switch (Crane/Teledyne Model T 40-80). The limit switch motion was caused by a water hammer shock generated by the cycling of the No. 32 MBFP recirculation valve (FCV-1116) while the manual isolation valve BFR-1-32 was closed. The water hammer occurred because of the pressure drop between valves FCV-1116 and the manual isolation valve. The recirculation valve FCV-1116 was cycled while troubleshooting a faulty limit switch on the valve.

A.6 Oyster Creek, LER 219/88-021 (Ref. 11)

On September 28, 1988, while operating at 100% power, it was determined that both the "A" and "B" isolation condensers (IC) were operating in an unanalyzed condition. Temperature data suggested that the steam lines to the ICs were at least partially filled with water. Analysis of the temperature data suggested existence of reverse flow through one-half of each IC and the possibility of subcooled condensate buildup in the steam lines to the IC. This raised concern over potential effects of increased piping loads, thermal stresses, and possible water hammer. The reactor was shutdown. The event was the subject of an NRC Augmented Inspection Team review and extensive licensee followup.

The steaming of the IC with water filled steam lines was outside operating conditions previously evaluated. A subsequent licensee Technical Data Report, TDR 950, was issued covering the event and addressed the water hammer concerns. It was concluded that water hammer had not occurred during the IC steaming and that other postulated transients would

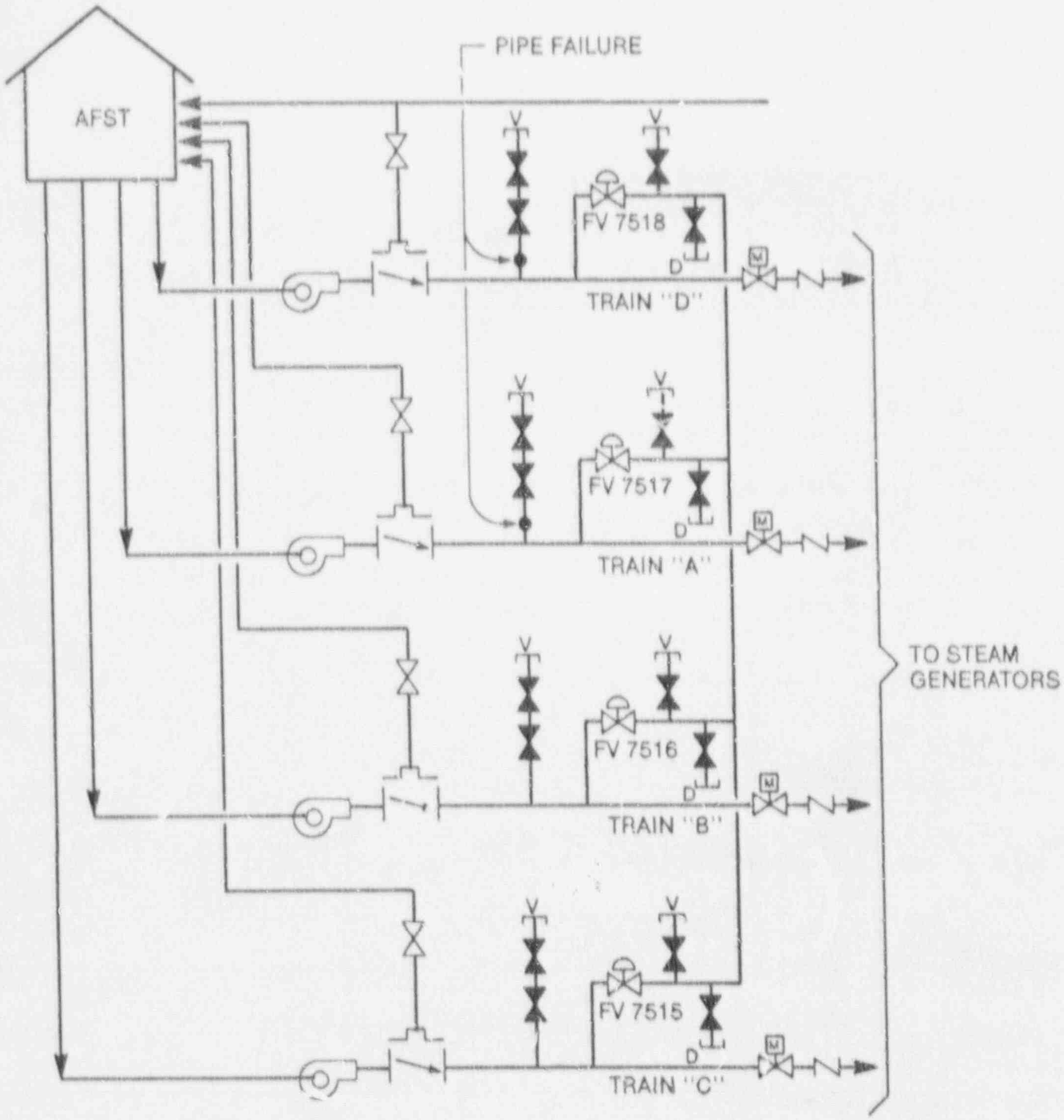

FIGURE A2. SOUTH TEXAS AFW SYSTEM SCHEMATIC

not result in water hammer. Operating procedures were implemented to limit water accumulation in the steam lines.

A.7 Waterford, LER 382/89-015 (Ref. 12)

With the plant at 100% power, a damaged pipe support was identified on steam generator No. 2 blowdown system piping during a routine system walkdown on July 14,1989. It was later determined that in this condition structural integrity of the blowdown system (including the outside containment isolation valve and shield building penetration) could not be assured during a seismic event. The support was undamaged when observed during a walkdown the week of June 19, 1989. The operating test "Engineered Safety Feature Actuation Signal (ESFAS) Subgroup Relay Test" was conducted between the two system walkdowns. This test involved cycling the inside containment isolation valve to verify its operability in response to a containment isolation actuation signal or an emergency feedwater system actuation signal. The procedure did not require shutting the outside containment isolation valve (See Figure A3) or to minimize the blowdown flow prior to opening the inboard isolation valve. Thus, a water hammer transient most likely occurred when the inboard isolation valve opened.

A.8 Oconee Unit 3, LER 287/89-002 (Ref. 13)

An anticipatory reactor trip occurred after the main turbine tripped. Following the trip, a water hammer transient in the main steam turbine bypass line to the "A" condenser resulted in damage to three pipe supports. The pipe was deflected 12 to 18 inches. Subsequent investigation indicated the most likely cause was water accumulation near an orifice in a drain line; however, an obstruction could not be verified. A station problem report was initiated to resolve problems with improper draining of the pipe.

A.9 Palisades, Morning Report (Ref. 14)

On April 25, 1990, gross deformation of seismic pipe supports [illegible] identified in piping from the "A" and "D" safety injection tanks (SITs) to the primary reac[illegible] system. Minor damage was also found to piping supports for the "B" and "C" SIT piping. An evaluation identified a water hammer event on October 1, 1987, that could have caused the damage. The exact cause is not clear. The primary coolant system was at hot shutdown with the temperature greater than 500° F. The SIT tanks normally have a 200 psig nitrogen overpressure, but the "A" tank had been vented to 50 psig. It was believed that this lowered pressure in combination with possible leaking check valves from the primary system resulted i[illegible]shing conditions and water hammer. Procedures were changed to prohibit bleed down of the SITs since late 1987.

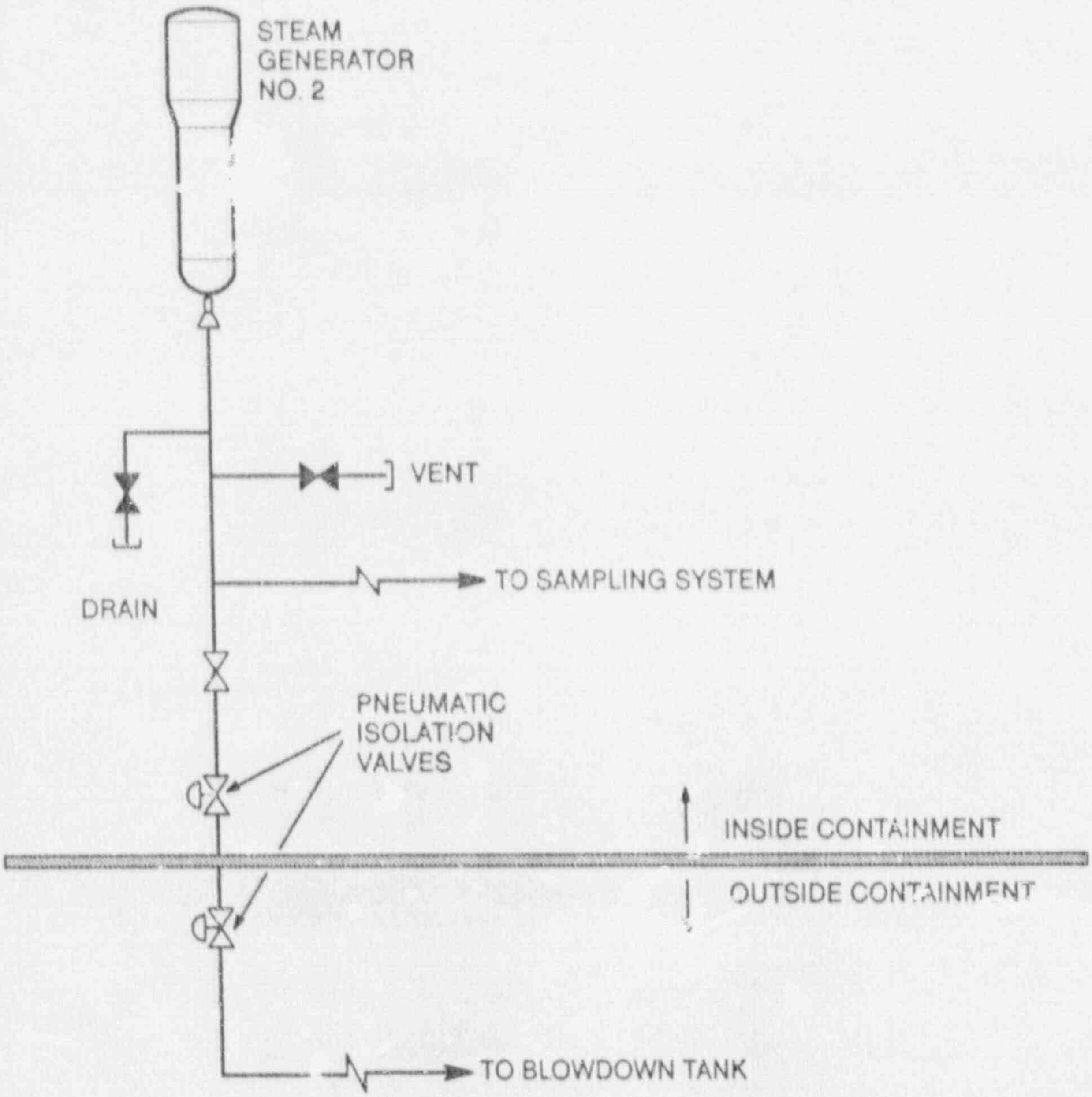

FIGURE A3. WATERFORD STEAM GENERATOR BLOWDOWN SYSTEM SCHEMATIC

A.10 ANO Unit 2, LER 368/88-023 (Ref. 15)

A mechanical snubber on the main steam supply line to the emergency feedwater (EFW) system turbine driven pump was found inoperable because of severe degradation of the snubber internals. The damaged snubber was discovered while conducting inservice inspections in accordance with technical specifications during refueling outage 2R6 in February 1988. The failure mode indicated the snubber had been subjected to an overload condition during the just completed operating cycle. The most probable cause was determined to be condensate buildup at a previously unidentified low point in the EFW system steam supply piping and subsequent "water slugging" upon starting the turbine driven EFW pump. Poor steam maintenance and inadvertent bypassing of steam traps for extended periods also contributed to the condensate buildup. This same snubber was found inoperable while performing inservice inspections during the 2R4 and 2R5 refueling outages. The 2R4 outage failure was attributed, at the time, to prior excessive "steam slugging" resulting from a past problem with overspeed trips of the turbine driven EFW pump. The 2R5 outage failure was attributed to vibration and overload which had occurred to a large number of mechanical snubbers manufactured by a specific vendor. Corrective action included modification of the EFW steam supply line to remove the low point and steam trap maintenance to inspect, clean, and rebuild as necessary.

A.11 Dresden Unit 2 LER 237/89-029-01 (Ref. 16)
Dresden Unit 3 LER 237/89-029-01
Dresden Unit 2 LER 237/89-029-01

A series of three events involving water hammer in the high pressure coolant injection (HPCI) system at Dresden Units 2 and 3 are discussed in LER 237/89-029-01. Preliminary indications of a precursor to the initial Unit 2 damage to the HPCI system were provided by measurement of increasing HPCI cubicle temperatures in May 1989. The pipe temperature at the HPCI pump was measured at 140° F while the piping between MOVs 2-2301-8 and 2-2301-9 was 160°F. Refer to Figure A4 for the normal HPCI system configuration. Further pipe temperature measurements in July 1989 identified the HPCI pump discharge pipe at 175° F while the pipe between MOVs 2-2301-8 and 2-2301-9 was 220° F. Subsequent closing and reopening of MOV 2-2301-9 produced pipe temperatures of 106° F after 12 hours and a return to 220° F after MOV 2-2301-9 was opened. Thus, check valve 2301-7 and MOV 2301-8 were both back leaking feedwater to the HPCI system piping. A pipe temperature survey conducted on October 23, 1989, revealed the HPCI pump discharge pipe temperature was 246° F while the pipe between MOVs 2-2301-8 and 2-2301-9 was 275° F. An evaluation determined that steam voids could form in certain sections of the pipe under these conditions. Subsequent inspections of the Unit 2 HPCI discharge piping supports identified there were deficiencies in 47% (or 16) of the supports. The Unit 2 HPCI system valve lineup was changed to that shown in Figure A5 which changes the injection valve function to MOV 2-2301-9 from MOV 2-2301-8. Also, with MOV 2-2301-8 open, MOV 2-2301-10 becomes an isolation valve subject to feedwater pressure.

As a result of the elevated temperatures discovered on the Unit 2 HPCI pump discharge piping, an investigation of the Unit 3 HPCI pump discharge pipe was initiated. Temperature measurements obtained with an infrared thermometer on October 31, 1989, identified HPCI pump discharge pipe temperatures ranging from 256° F between MOVs 3-2301-8 and 3-2301-9 to 112° F at the discharge of the HPCI pump. This was evidence of possible steam void formation in the Unit 3 HPCI pump discharge piping. Subsequent monitoring of the HPCI pump discharge pipe temperature and pressure revealed that the temperature was increasing on November 3, 1989. The temperature increase was attributed to leakage past MOV 3-2301-10. MOV 3-2301-10 was manipulated both electrically and manually to seat the valve and MOVs 3-2301-15 and 49 were also closed. After the latter MOVs were closed, the pump discharge pressure increased from 650 psig to 1070 psig which confirmed that leakage through MOV 3-2301-10 was stopped. The Unit 3 HPCI system valve lineup was changed (MOVs 3-2301-15 and 49 were closed and MOV 3-2301-48 was opened) to that shown in Figure A6. Subsequent inspection of Unit 3 HPCI discharge pipe supports identified there were deficiencies in 52% (or 21) of the supports. These events at Units 2 and 3 in October and November 1989 were reviewed by an NRC Augmented Inspection Team.

On March 19, 1990, after completion of routine HPCI valve operability surveillance testing and while performing quarterly valve timing testing on the Unit 2 HPCI pump discharge valves, the Unit 2 Shift Supervisor discovered banging noises emanating from the HPCI pump discharge piping. The valve timing test was terminated and the HPCI system valve lineup was returned to that shown in Figure A5. The pipe banging and motion was monitored until it eventually ceased approximately 1.5 hours later. Subsequent investigation involving valve manipulation and HPCI pump discharge pipe temperature measurements led the licensee to conclude that feedwater back leakage through HPCI test return valve MOV 2-2301-10 was the root cause of this event. Based on the investigation, it was postulated that MOV 2-2301-10 did not fully close after one of the manipulations involved in complying with plant Technical Specification required valve and HPCI system tests. This could occur because of the MOV control system and the way in which the limit switches are used. This valve does not have a seal-in feature to complete the stroke after closure initiation. In addition, the limit switches are set to provide a torque switch bypass function in the open direction until the valve is 25 percent open. The type of limit switch used also controls the indicated valve close light in the control room. Thus, an operator who removed a closure signal when the control room panel lights indicated the valve was closed could leave the valve nearly 25% open. A procedure was introduced to continue the closure sig 1 30 seconds after the panel lights indicate MOV 2-2301-10 is closed. The Unit 2 HPCI syst revised valve lineup was left to correspond with Figure A6.

A.12 Additional Related Events

The 1986 water hammer event at Susquehanna Unit 2 also involved hydrodynamic interactions of the residual heat removal (RHR) system with a loss of the shutdown cooling mode of

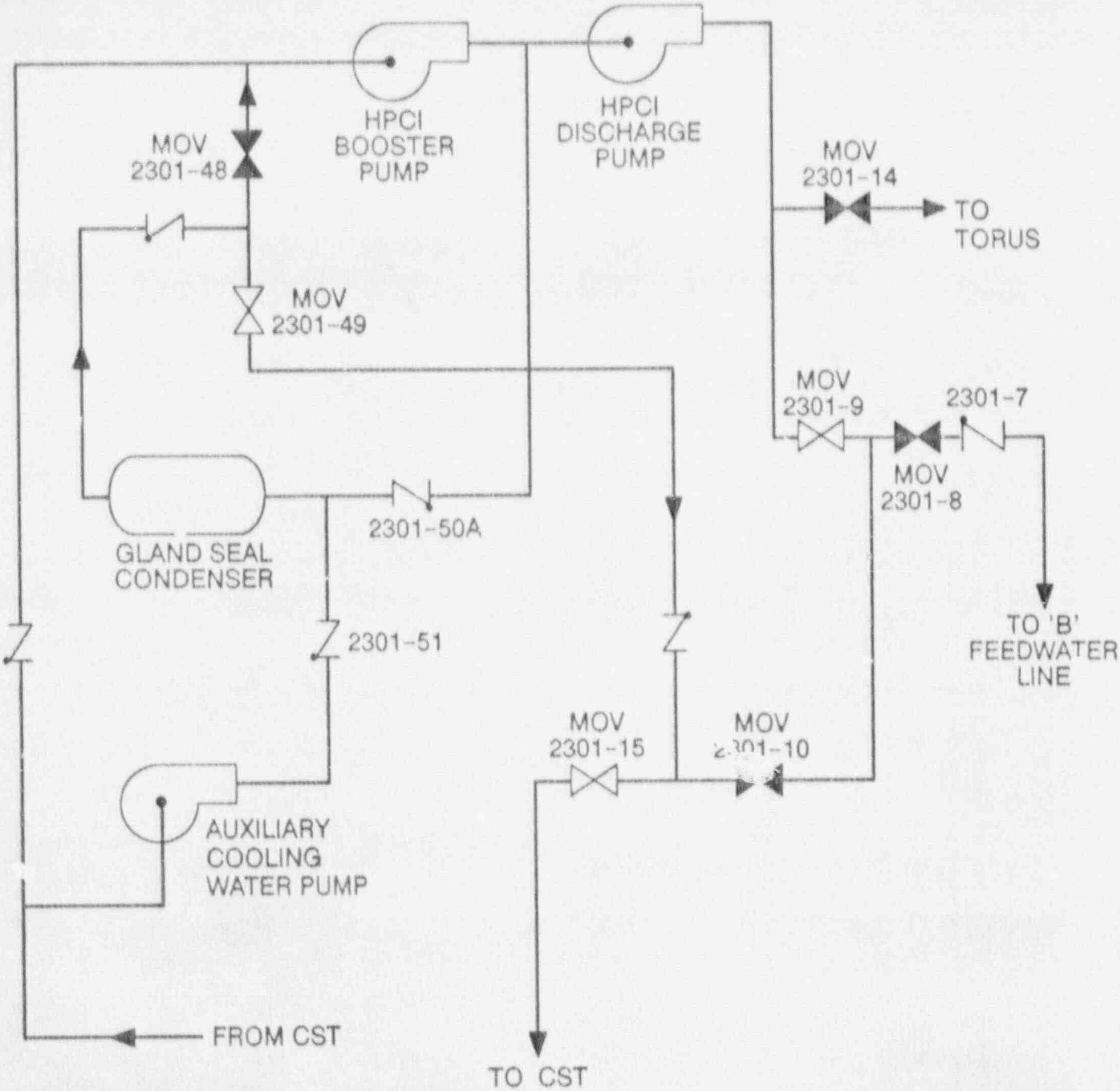

FIGURE A4.
BASIC HPCI SYSTEM (UNIT 3 PRESENTLY)

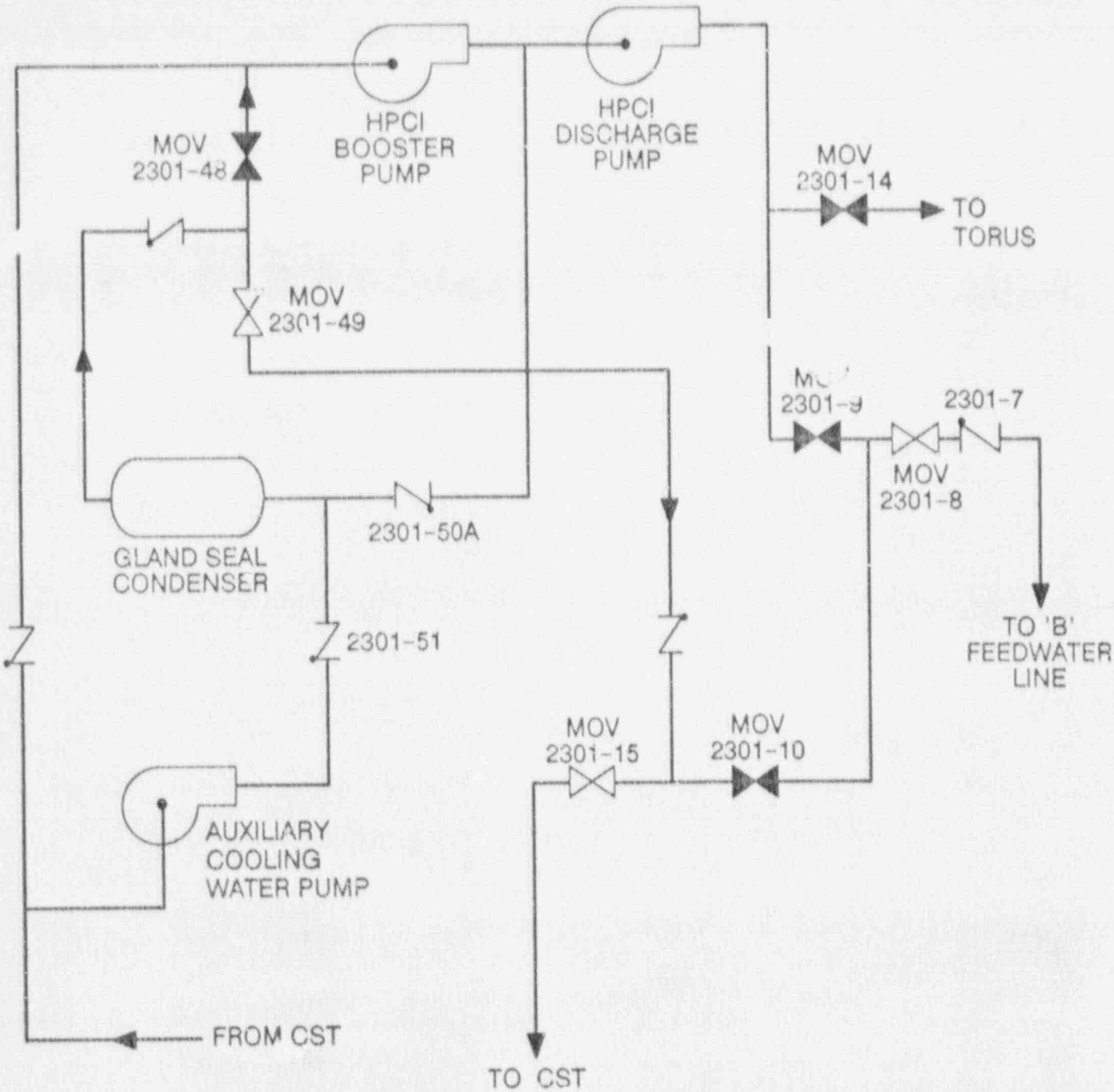

FIGURE A5.
UNIT 2 HPCI ALTERNATE VALVE LINEUP (POST OCTOBER EVENT)

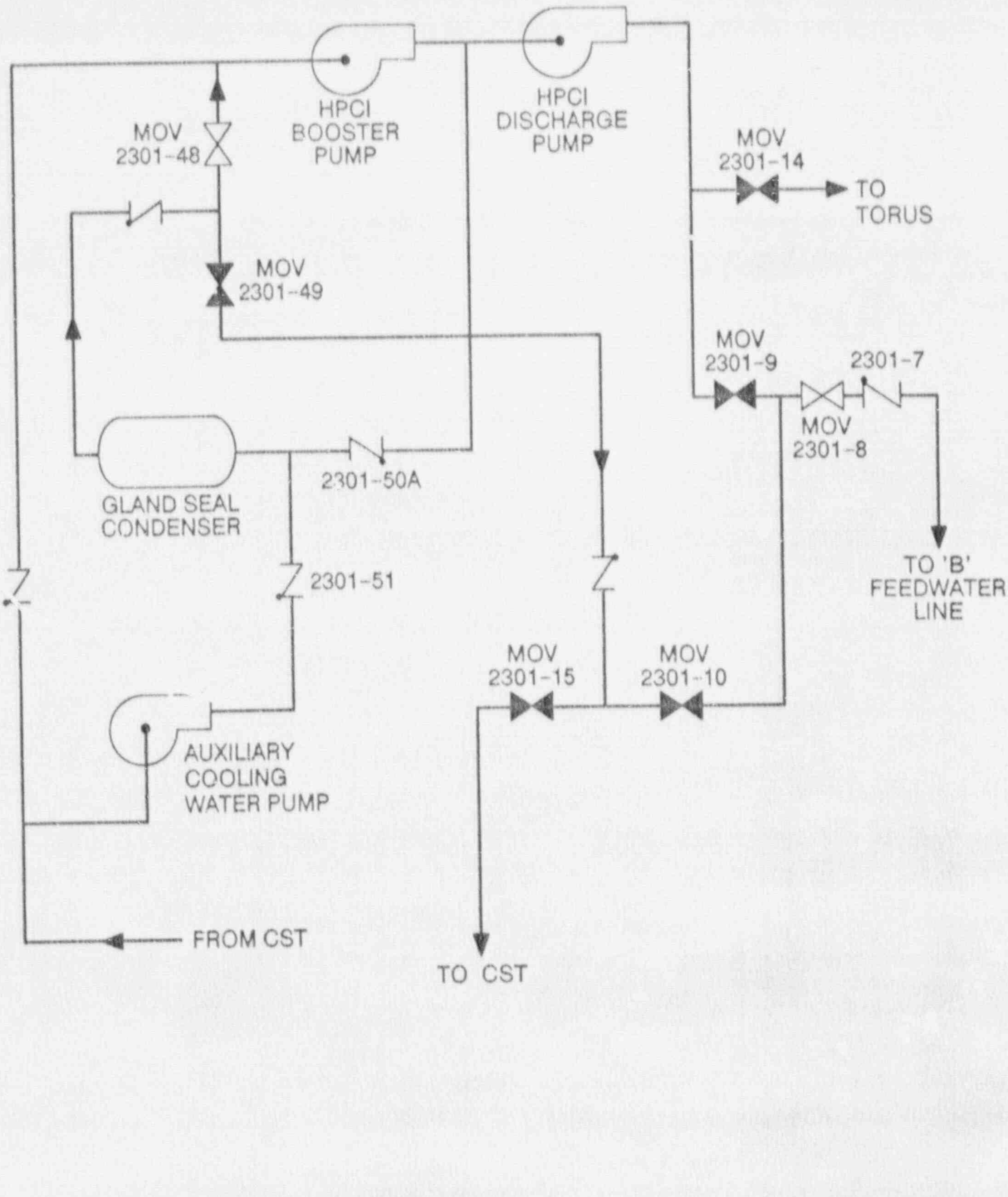

FIGURE A6.
HPCI REVISED ALTERNATE VALVE LINEUP
(UNIT 2 PRESENTLY & UNIT 3 POST OCTOBER EVENT)

operation. This behavior was also of interest for this study. Several similar events at other plants were identified and are discussed in this section.

The 1986 event at Susquehanna Unit 2 was discussed with licensee staff to determine the causes for the RHR isolation valve closures. It was found that several events have occurred which involve closure of the RHR suction valves from the recirculation loop while in the shutdown cooling mode of operation. Although water hammer has not always been a result of the valve isolations, the events have involved loss of shutdown cooling. There have been seven reported events (LERs 387/89-003, 88-011, 87-028, and 84-020 for Unit 1 and 388/88-003, 86-015, and 85-016 for Unit 2). Most of these events involved valve isolation while either switching RHR pumps in the shutdown cooling mode of RHR or starting the RHR pump.

There are five signals that would automatically close the F008 valve at the Susquehanna Units. These are:

(a) Reactor vessel level 3,
(b) Reactor pressure 96 psig,
(c) High RHR room temperature,
(d) High equipment area high differential temperature,
(e) RHR shutdown cooling suction high flow.

The licensee believes there is either a high pressure or high flow signal causing the valves to close (either a spurious signal or fluid hydraulic transients affecting the instrumentation). LER 387/89-003 indicates that additional instrumentation has been installed to determine flow and pressure changes if another event occurs. They have also installed a two-second time delay in the drop out relay for MOVs F008 and F009. This should prevent closure due to a transient signal related to flow or pressure.

A series of similar RHR isolation valve closures during the shutdown cooling mode of operation have also occurred recently at Fitzpatrick. The valve isolations occurred in January, March, April, and June 1990, and are discussed in LERs 333/90-002, 90-011, 90-016, and Morning Report 18770, respectively. The January 1990 event involved a reactor high pressure isolation logic trip. A hydraulic pressure transient was suspected but was not confirmed. System drawings indicated the pressure transmitters for the isolation logic were located on the suction line of recirculation pump "A" while the RHR system was discharging into the "B" reactor recirculation loop so the vessel volume should have isolated flow transients from the instrumentation. After the March 1990 event which also occurred on a reactor high pressure isolation logic trip, it was determined that the pressure transmitters were located in the "B" reactor recirculation loop rather than the "A" recirculation loop. Thus, the pressure transient was postulated as due to reverse flow through the "B" recirculation pump due to the higher pressure discharge from the RHR system. The isolation valve closures in April were attributed to chattering pressure switches. The June event was identified as a

spurious signal. Each isolation valve closure has occurred on starting a pump, stopping a pump, or changing the flow rate.

Closure of the RHR isolation valves has also occurred at La Salle Unit 2 and Pilgrim during 1990. The La Salle event, discussed in LER 374/90-003, involved closure of the shutdown cooling inboard isolation valve caused by a shutdown cooling suction high flow isolation signal when the "B" RHR pump was started. The cause of the high flow isolation signal was attributed to excessive differential pressure (DP) fluctuations at the high flow isolation switch due to short duration flow instabilities in the suction flow elbow. Similar dP fluctuations which had occurred at Unit 2 (LER 374/89-005) were also detected in Unit 1 and are documented in La Salle Special Test, LST-89-81, "1E31-N012AA/AB Pulsation Damper Response Characteristics." During the Unit 1 third refueling outage, dP fluctuations occurred with shutdown cooling operations in Plant Conditions 3 (Hot Shutdown), 4 (Cold Shutdown), and 5 (Refueling). The high flow relays were modified to include a one second time delay. This modification has been approved for Unit 2. Further, LER 374/89-005 for La Salle Unit 2 discusses several additional events involving closure of isolation valves while attempting to use the shutdown cooling mode of RHR. At least six other LER's involving isolation of shutdown cooling were submitted during 1985.

The Pilgrim events with closure of the RHR isolation valves are discussed in LER 293/89-039 and Initial Notification number 18823. These events occurred on December 9, 1989, and July 3, 1990. The December event involved closure of both suction isolation valves [illegible] seconds after starting the "A" RHR pump for shutdown cooling. Valve closure was the result of a hydrodynamic transient that actuated the pressure switches connected to the "A" loop recirculation pump suction piping. The root cause was cited as unvented air in the shutdown cooling system suction piping. The July 3, 1990, valve closure was believed caused by a similar air problem.

Only a few of these additional related events involved water hammer. However, there have been numerous events in which closure of the isolation valve occurred while using or attempting to use the shutdown cooling mode of RHR in BWR plants. These isolation events occurred with pump starts, pump stops, switching pumps, and changes in flow. It appears there are hydrodynamic interactions within the system or between systems that affect system operation and control instrumentation signals. Closure of the isolation valve is followed by trip of the pump so shutdown cooling is lost for some period of time. Restart of shutdown cooling could lead to water hammer if procedures are inadequate or not followed correctly.

UNITED STATES

NUCLEAR REGULATORY COMMISSION

OFFICE OF NUCLEAR REACTOR REGULATION

WASHINGTON, D.C. 20555

NRC INFORMATION NOTICE NO. 91-XX: A REVIEW OF WATER HAMMER EVENTS AFTER 1985

Addressees:

All holders of operating licenses or construction permits for nuclear power reactors.

Purpose:

This Information Notice is intended to provide addresses with information obtained from an evaluation of water hammer events which occurred from 1986 through March 1990. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid problems. However, suggestions contained in this Information Notice do not constitute NRC requirements; therefore, no specific action or written response is required.

Background:

Water hammer was originally addressed as NRC Unresolved Safety Issue (USI) A-1. This USI was considered resolved with the issuance of NUREG-0927, Revision 1, in March 1984. The staff concluded that new requirements to reduce the number of water hammer events was

not supported by cost-benefit guidelines. However, the staff provided guidelines concerning measures for water hammer prevention and mitigation in NUREG-0927, Revision 1. In addition, a staff reassessment of water hammer was initiated after the San Onofre Unit 1 event in November 1985. The reassessment, which was completed in 1986, confirmed the original conclusions that new or additional requirements to reduce the number of water hammer events were not supported by cost-benefit guidelines. The 1986 reassessment found that the frequency of water hammer events had decreased significantly since the initial review and that there were no new phenomena as causes of water hammer.

Description of Circumstances:

The initial USI A-1 assessment involved review of 148 reported events from 1969 to 1980 while the reassessment of the San Onofre event reviewed 40 events from 1981 to 1985. Water hammer events since January 1, 1986, were evaluated with respect to previous NRC studies in response to a Staff Actions Memorandum based on a broad-based diagnostic evaluation at a PWR plant in August and September 1989. A search of NRC databases for the time frame from 1986 through March 1990 identified 12 water hammer events. Table B1 provides a list of those events by plant name and unit, data source, and affected system.

Each recent event was reviewed to determine the nature of the event and assess whether it was associated with new physical phenomena. The review also concentrated on identification of common mode aspects and lessons that may be useful to assist other plants in prevention of situations that could result in water hammer.

Discussion:

The water hammer events listed in Table B1 occurred at both BWR and PWR plants. The BWR plant systems involved were the shutdown cooling mode of residual heat removal (RHR), the isolation condenser, and high pressure coolant injection (HPCI). The PWR plant systems involved were main steam, auxiliary feedwater (AFW) steam supply, steam generator blowdown, feedwater, accumulator (fill lines and injection to reactor coolant system) and the AFW vent lines. These systems have been associated with water hammer in previous studies. Even though some specific aspects such as the accumulator fill lines and injection line and the AFW vent lines appear to be different areas, the physical phenomena involved steam void formation and fluid flow between high and low pressure systems which are likely candidates for water hammer.

Some cited water hammer causes for these 12 recent events include failure to fill and vent properly, rapid valve stroking, lack of guidance about system configuration, low point water accumulation, depressurization of a system which could cause local flashing, and bypassing steam traps. These causes were addressed by the staff guidance (NUREG-0927, Revision 1) issued for the resolution to USI A-1. Thus, it would seem that a more vigilant implementation of staff guidance could result in fewer water hammer events even though the overall frequency and number of water hammer events for this review was less than observed in previous evaluations.

However, a few of the recent events in Table B1 exhibit characteristics not emphasized in previous studies and offer lessons beyond implementation of staff guidance for resolution of USI A-1. The characteristics are: (1) hydrodynamic interactions between systems (or trains), (2) system realignments involving MOV position changes can involve complex issues

concerning component operability as well as water hammer, and (3) RHR pump maneuvering in BWR plants has resulted in a number of isolation valve closures followed by loss of shutdown cooling and a few water hammer events (Note: Only the water hammer events are identified in Table 1 for Susquehanna.) The isolation valve closures along with all water hammer events are discussed in AEOD Report E91-01.

A brief description of the events with these new characteristics follows below.

On October 12, 1986, Susquehanna Unit 2 was in the shutdown cooling mode, condition 4, with the "D" residual heat removal (PHR) pump in service. With the "D" pump running, the "B" RHR pump was then started. The switchover to the "B" pump in service was completed with shutdown of the "D" pump. However, at approximately the same time, closure of the outboard isolation valve occurred in the letdown line from the "B" recirculation loop to the suction of the "B" RHR pump. Closure of the suction valve caused the "B" RHR pump to trip. Operations personnel reset the logic and reopened the suction valve which resulted in water hammer followed by valve reclosure. The water hammer was due to partial draindown of the system through a pathway to the condenser. This pathway was present to control reactor water level while the RHR system was in service. The operators failed to fill and vent the system piping after the "B" RHR pump tripped.

On May 12, 1987 at Trojan, the "A" accumulator one-inch fill line ruptured at the nozzle to pipe weld while transferring water from the "A" accumulator to the "D" accumulator. Approximately 2000 gallons of water was released to the containment. The "A" accumulator was at 583 psig and the "D" accumulator was depressurized. Failure was due to low cycle, high stress fatigue cracking. After repair, the pipe again ruptured when water transfer through the fill lines was attempted with the "A" accumulator at 650 psig and the "D"

accumulator depressurized. Excessive reverse flow through the packless diaphragm globe valve caused cyclic vibration. Procedures were in place to transfer water between accumulators via the sample lines. Water was transferred between the accumulators via the fill lines because the sample lines were tagged out for maintenance. A dynamic analysis which modelled backflow through the fill line showed that loads far in excess of those necessary to fail the pipe would be imposed on the nozzle-to-pipe weld. Also, a backflow test through a packless globe valve similar to the valve in the accumulator fill line resulted in a pipe failure at a flow of about 70 gpm. Operating procedures were revised to prohibit water transfer between the accumulators.

On November 5, 1987, while South Texas Unit 1 was in mode 4, prior to initial criticality, a one-inch double valve vent line in the pump discharge piping of the auxiliary feedwater (AFW) train "A" broke off. A second failure occurred three days later in a similar manner in a double valve instrument tap for the train "D" AFW pump discharge line. The initial assessment cited the cause as water hammer resulting from improper venting of the system. The AFW system continued to experience vibration events. Subsequent testing identified that flow control valves in Train "A" and "D" introduced a pressure fluctuation when they were in a highly throttled position. The dominant pressure fluctuation frequency of 24 Hz matched one of the piping system acoustic natural frequencies. Mechanical stops were installed to prohibit excessive throttling of the valves. Resolution of this issue involve an extensive test program and special reports ST-HL-AE-2461 and ST-HL-AE-2516 were issued.

A series of three events involving water hammer in the HPCI system occurred at Dresden Units 2 and 3. Preliminary indications of a precursor to the initial Unit 2 damage to the

HPCI system was preceded by measurement of increasing HPCI cubicle temperatures in May 1989. The pipe temperature at the HPCI pump was measured at 140° F while the piping between MOVs 2-2301-8 and 2-2301-9 was 160° F. Additional pipe temperature measurements in July 1989 identified HPCI pump discharge pipe at 175° F while the pipe between MOVs 2-2301-8 and 2-2301-9 was 220° F. The normal HPCI system configuration is shown in Figure B1.

It was found that check valve 2301-7 (Feedwater/HPCI isolation valve) and MOV 2301-8 (HPCI injection valve) were both back leaking feedwater to the HPCI system piping. A pipe temperature survey conducted on October 23, 1989, revealed HPCI pump discharge pipe temperature was 246° F while the pipe between MOVs 2-2301-8 and 2-2301-9 was 275° F. An evaluation determined that steam voids could form in certain sections of the pipe under these conditions. Subsequent inspections of the Unit 2 HPCI discharge piping supports identified there were deficiencies in 47% (or 16) of the supports. The Unit 2 HPCI system valve lineup was changed (See Figure B2) so that the injection valve function was moved to MOV 2-2301-9 from MOV 2-2301-8. Also, MOV 2-2301-10 became an isolation valve subject to feedwater pressure. Subsequent inspection of Unit 3 HPCI piping found similar elevated temperatures with pipe support deficiencies found in 52% (or 21) of the supports. The Unit 3 inspection also found that other valves in the HPCI system could leak so the valve lineup was changed to that shown in Figure B3.

At Unit 2 on March 19, 1990, after completion of routine HPCI valve operability surveillance testing and while performing valve timing testing on the HPCI pump discharge valve, the Unit 2 shift supervisor discovered banging noises emanating from the HPCI pump discharge piping. The valve timing test was terminated and the HPCI system valve lineup was returned to the configuration prior to testing (See Figure B2). Subsequent investigation involving

valve manipulation and HPCI pump discharge pipe temperature measurements led the licensee to conclude that feedwater back leakage through the HPCI test return valve 2-2301-10 was the root cause of the event. Based on the investigation, it was postulated that MOV 2-2301-10 did not fully close after one of the manipulations involved in complying with plant Technical Specification required valve and HPCI tests. This valve did not have a seal-in feature to complete the stroke after initiation. In addition, the limit switches were set to provide a torque switch bypass function in the open direction until the valve was 25% open. This limit switch also controlled the valve close light indication in the control room. Thus, a control room operator who removed a closure signal when the control room panel lights indicated the valve was closed could leave the valve approximately 25% open. A procedure was introduced to continue the closure signal 30 seconds after the panel light indicated MOV 2-2301-10 was closed. The HPCI system lineup was revised to that shown in Figure B3.

Additional details of the water hammer events listed in Table B1 can be obtained by reviewing the identified information source. Also, AEOD report E91-01 provides a discussion of the assessment for these water hammer events and the closure of the BWR shutdown cooling isolation valves.

This Information Notice requires no specific action or written response. If you have any questions about the information in this notice, please contact one of the technical contacts listed below or the appropriate NRC project manager.

Charles E. Rossi, Director
Division of Operational Events Assessment
Office of Nuclear Reactor Regulation

Technical Contact:
Earl J. Brown, AEOD
(301) 492-4491

TABLE B-1. WATER HAMMER EVENTS AFTER 1985

Plant	DATA SOURCE (LER or Other Report)	SYSTEM
Susquehanna 2	388/86-01[illegible]-01	RHR-Shutdown Cooling Model
Sharon Harris 1	400/87-029-01	Steam Generator Blowdown
Trojan	344/87-01[illegible]-01	Accumulator Fill lines
South Texas 1	498/87-016-01	AFW Vent lines
Indian Point 3	286/88-002	Feedwater
Oyster Creek	219/88-021	Isolation Condenser
Waterford 3	382/89-015	Steam Generator Blowdown
Oconee 3	287/89-002	Main Steam
Palisades	(Inspection Report) 255/90-14	Accumulator Injection
ANO 2	368/88-023	Steam Supply to AFW
Dresden 2,3	237/89-029-01	HPCI
Dresden 2	237/89-029-01	HPCI

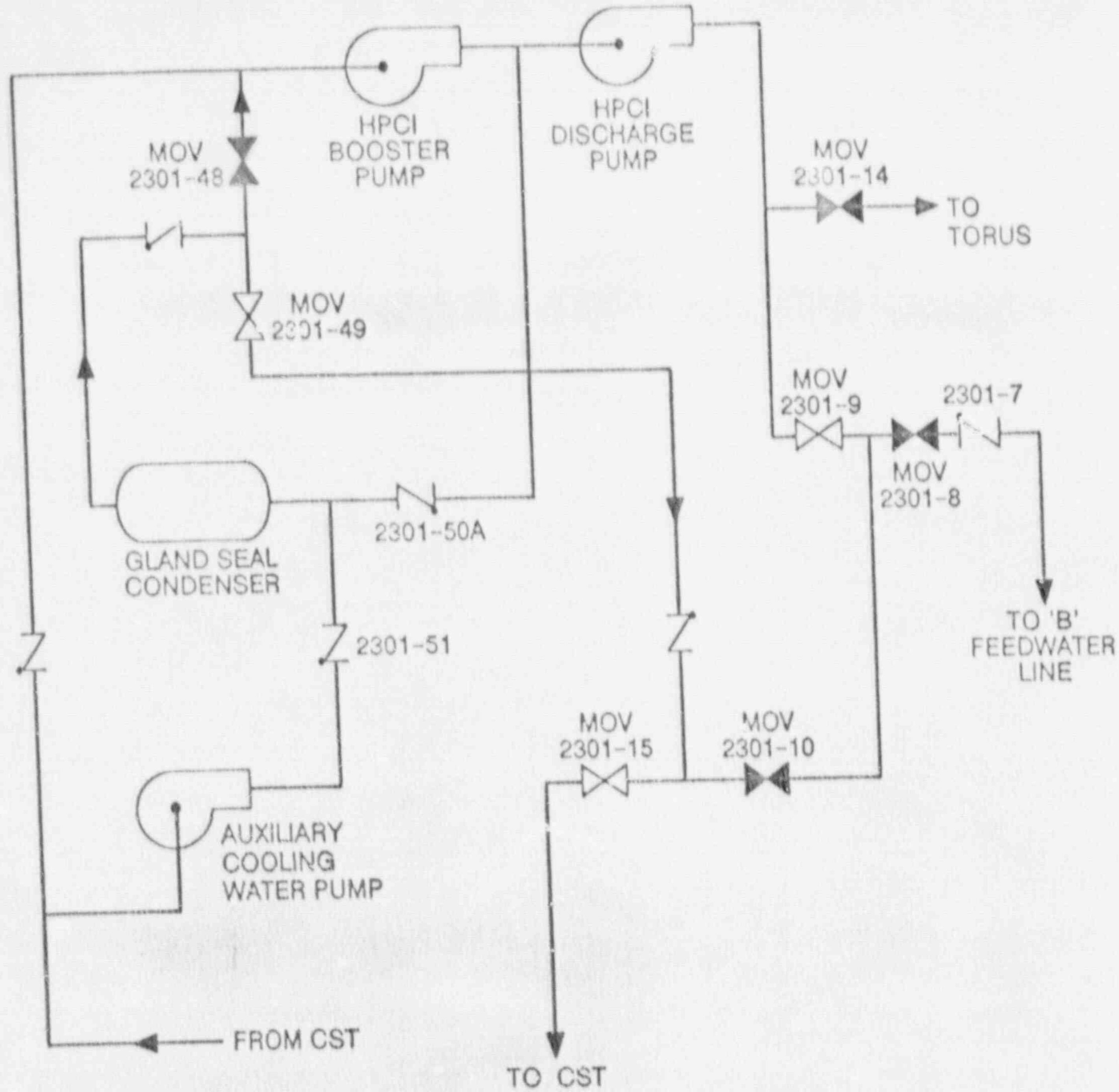

FIGURE B1
BASIC HPCI SYSTEM (UNIT 3 PRESENTLY)

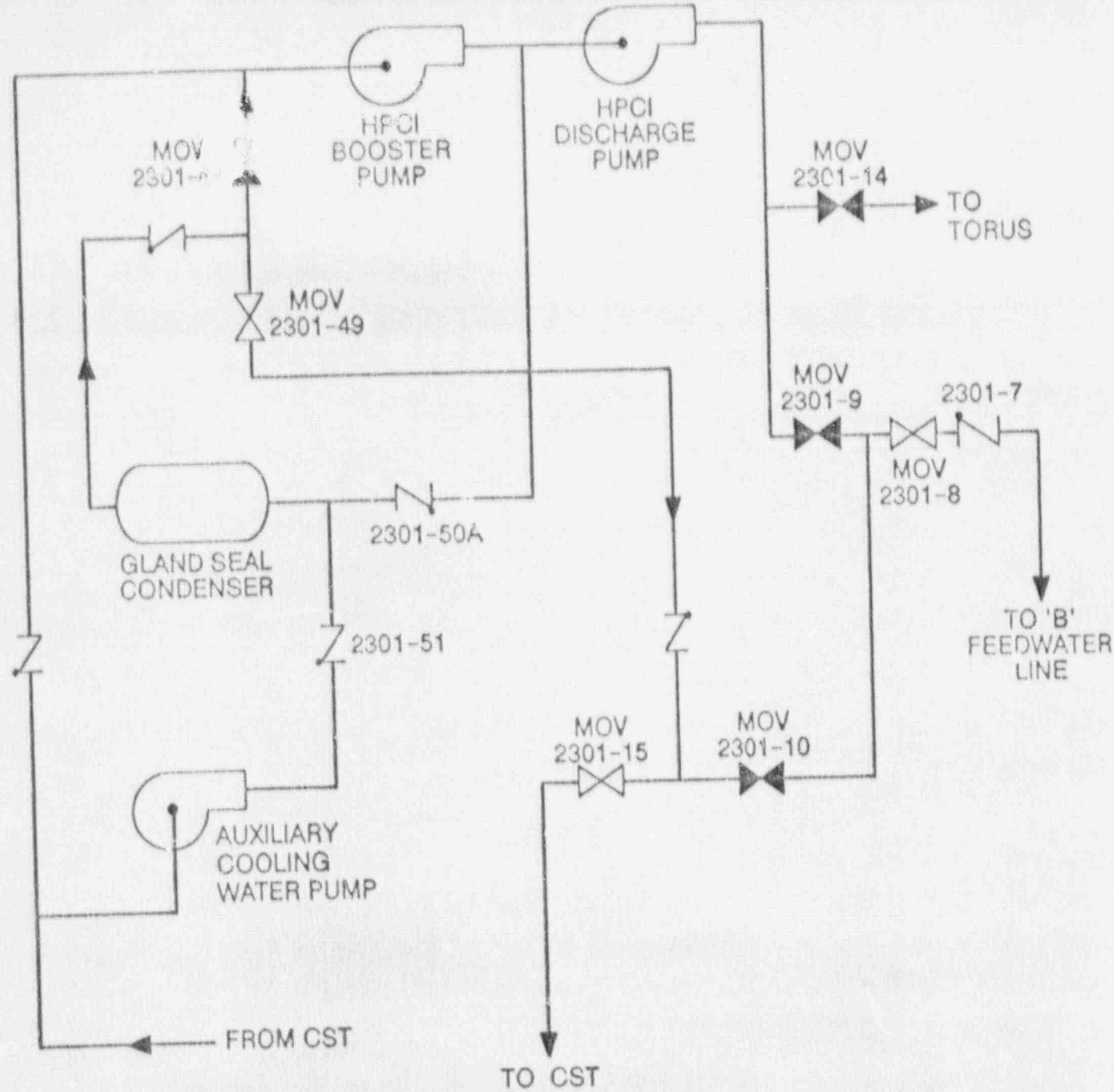

FIGURE B2
UNIT 2 HPCI ALTERNATE VALVE LINEUP (POST OCTOBER EVENT)

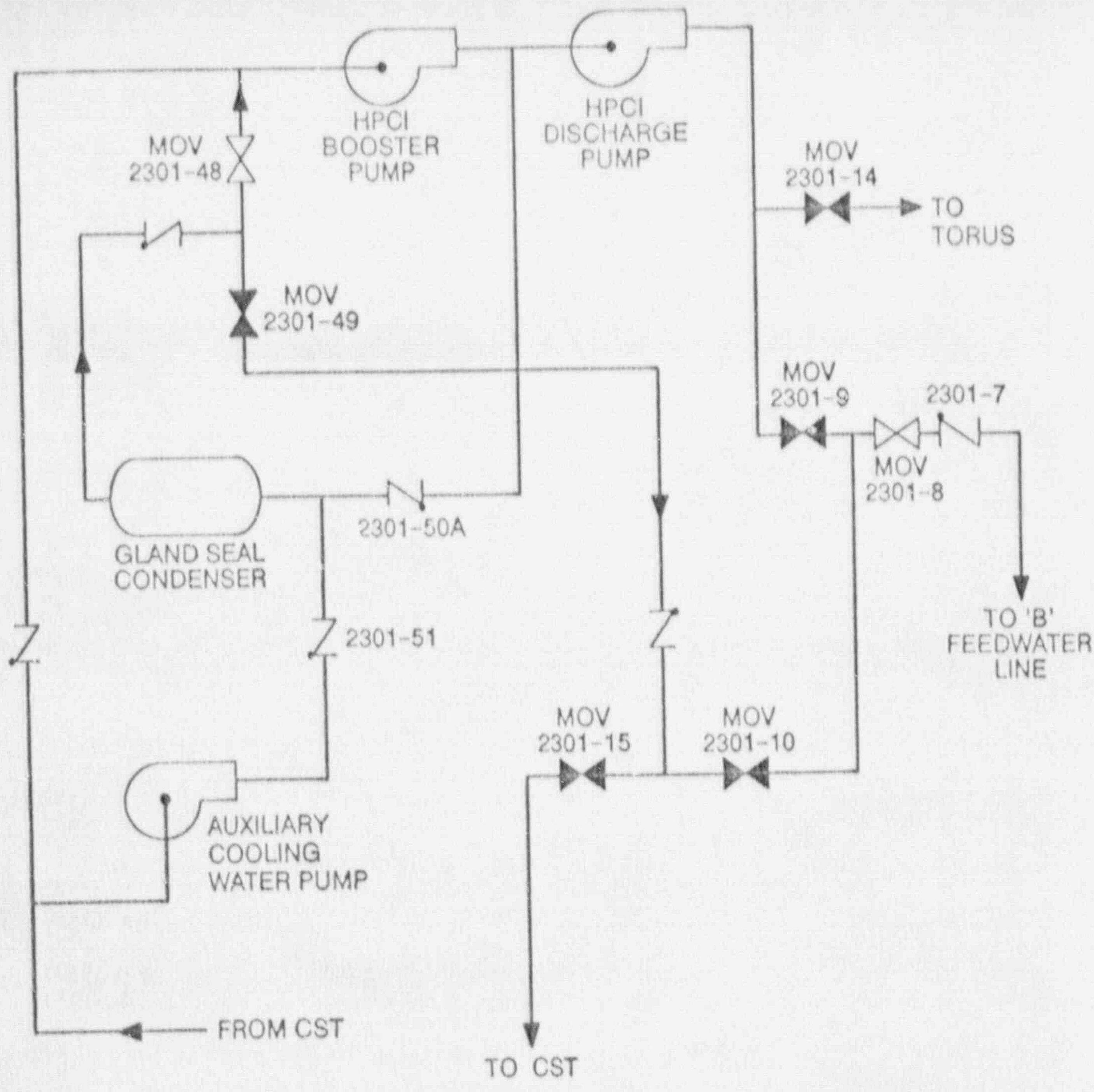

FIGURE B3
HPCI REVISED ALTERNATE VALVE LINEUP
(UNIT 2 PRESENTHLY & UNIT 3 POST OCTOBER EVENT)