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INTERFACING SYSTEMS LOCA AT BWRs

DRAFT LETTER REPORT

T. Chu, S. Stoyanov, R. Fitzpatrick

Risk Evaluation Group

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Department of Nuclear Energy
Brookhaven National Laboratory
Upton, NY 11973

1. INTRODUCTION

1.1 Background

The Reactor Safety Study, WASH-1400,[1] identified an intersystem loss-of-coolant accident in a PWR as a significant contributor to risk from core melt accidents (Event V). As a result of the study and the TMI-2 accident, all light water reactors with operating license on February 23, 1980 were required[2-3] to periodically test or continuously monitor the Event V valves. The Event V arrangement is defined to be (1) two check valves in series, or (2) two check valves in series with an open motor-operated valve. Such valve arrangements are commonly used in PWRs but not BWRs. Acceptable methods to assure component integrity include:

(1) continuous monitoring on the low pressure side of each check valve,

(2) periodic IST leakage testing on each check valve every time the plant is shutdown and/or each time either check valve is moved from the fully closed position,

*(3) periodic ultrasonic examination on each valve every time the plant is shutdown and/or each time either check valve is moved from the fully closed position, or

*(4) periodic radiographic examination on each valve every time the plant is shutdown and/or each time either check valve is moved from the fully closed position.

For plants which received operating licenses after October 1980, leak tests of all pressure isolation valves (that is; two valves in series which separate high pressure RCS from associated low pressure systems) are required.[4] Systems that are rated at full reactor pressure on the discharge side of pumps but have pump suction below reactor coolant system pressure are not normally considered to be barriers unless the pumps are of the positive displacement type. Pressure

*No plant has ever proposed these methods and thus such methods have not received a detailed review.

isolation valves are required to be Category A or AC per IWV-2000 of ASME Code for Boilers and Pressure Vessels. Limiting conditions of operation and surveillance requirements are specified in Technical Specifications. The leak test programs of the applicants were reviewed by the Mechanical Engineering Branch, Division of Engineering, NRR, until the recent NRR reorganization. Vendor program branches now conduct these reviews. A proposed Appendix A to Standard Review Plan, Section 3.9.6 was written to include leak testing of pressure isolation valves but was never approved.[5]

Since early 1981, the NRR staff has been backfitting operating reactors by requiring, via in-service inspection programs, leak testing of all PIVs that connect the high pressure RCS to lower pressure systems.[6] This backfit has been completed on approximately 15 plants licensed prior to the accident at Three Mile Island. On April 20, 1981, orders were sent to 32 PWRs and 2 BWRs which required leak rate testing of event V PIVs.

Due to the questionable basis for the 1 gpm acceptance criterion for leak rate tests from Near Term Operating License (NTOL) applicants,[7] the NRR staff changed the acceptance criterion.[8] The leak rate on each valve must be no greater than 1/2 gallon per minute for each nominal inch of valve size and no greater than 5 gpm for any particular valve. On July 24, 1985, the Committee to Review Generic Requirement (CRGR) responded favorably to this change,[9] but questioned the safety rationale that is used to justify the full extent of the PIV testing that is required of NTOLs, and the retroactive applications to the operating reactors. To address the concern of CRGR, NRR put a program in place under Generic Issue 105 to develop the necessary information to prepare a new NRC staff position on testing of PIVs. The current leak testing requirements for PIVs are stated in the PWR standard technical specifications as follows:

a. At least once per 18 months.

b. Prior to entering hot shutdown when the plant has been in cold shutdown for 72 hours or more and if leakage testing has not been performed in the previous 9 months.

c. Prior to returning the valve to service following maintenance, repair or replacement work on the valve.

d. Within 24 hours following valve actuation due to automatic or manual action or flow through the valve.

In BWRs, items b and d have been omitted in many recent licensing actions because the PIVs have readout in the control room and alarms if pressure is exceeded on the low pressure side. In some cases interlocks are provided to prevent both valves from being opened when the pressure is too high. NRR recently recommended the elimination of requirements b and d in all plants as being too stringent.[10] Item d above is believed to impose the most hardship on utilities in terms of its potential effect on plant operation because leakage in excess of the acceptance criterion requires that the plant be brought back to cold shutdown to repair the failed valve.

1.2 Objective

Recent operating experience indicates that the pressure isolation valves may not adequately protect against overpressurization of low pressure systems unless their integrity is verified by periodic testing as outlined above.[11] Overpressurization of low pressure system may result in rupture of low pressure piping. This, if combined with failures in the emergency core cooling systems, would result in a core melt accident with an energetic release outside the containment. Some ECCS failures may be a direct result of the rupture and/or its environmental affects.

The objective of this work is to provide technical support to the NRC, Reactor Safety Issues Branch, for the meaningful resolution of the generic issue. This work includes, survey and analysis of representative plants to determine core melt risk due to failure of pressure isolation valves, and determination of corrective actions such as valve leakage testing or not testing at pressure.

1.3 Organization of Report

Chapter 2 and Appendix A provide detailed information on the interfacing lines identified for the selected plants. Chapter 3 and Appendix B provide detailed information on the survey of operating experience, and the causes of PIV failures. Chapter 4 and Appendix C provide the detailed quantification for the interfacing lines identified in Chapter 2 using the failure experience and data found in Chapter 3 and Appendix D, respectively. Chapter 5 provides recommended changes that could be made to address the significant items identified from the Chapter 4 results in order to lower the core damage frequency from interfacing systems LOCA.

1.4 References

1. "Reactor Safety Study - An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plant," WASH-1400 (NUREG-75/014), USNRC, October 1975.

2. Letter to all LWR licensee on "LWR Primary Coolant System Pressure Isolation Valves," from Darrel G. Eisenhut, Acting Director, Division of Operating Reactors, Office of Nuclear Reactor Regulation, USNRC, February 23, 1980.

3. "Order for Modification of License Concerning Primary Coolant System Pressure Isolation Valves," Letter from Darrel G. Eisenhut, Director, Division of Licensing, Office of NRR, USNRC, to Eugene R. Mathews, Vice President, Power Supply and Engineering, Wisconsin Public Service Corporation, April 20, 1981.

4. Leak Tight Integrity of Primary Coolant System Pressure Isolation Valves," Memorandum from J. Knight, Assistant Director for Components and Structure Engineering, Division of Engineering, to R. Tedesco, Assistant Director for Licensing, Division of Licensing, Office of Nuclear Reactor Regulation, USNRC, October 15, 1980.

5. "LWR Reactor Coolant System Pressure Isolation Valves," Memorandum from Darrel G. Eisenhut, Director, Division of Licensing, to Richard H. Vollmer, Director, Division of Engineering, Office of NRR, USNRC, March 30, 1981.

6. "Leak Test Requirements for Reactor Coolant System Pressure Isolation Valves," Memorandum from G. E. Edison, Chief, Technical and Operations Support Branch Planning and Program Analysis Staff, to Harold R. Denton, Office of NRR, USNRC, June 14, 1985.

7. "Pressure Isolation Valve Leak Test Acceptance Criteria - NTOLs," Memorandum from James P. Knight, Assistant Director for Components Structures Engineering, Division of Engineering, to Richard H. Vollmer, Director, Division of Licensing, Office of NRR, USNRC, May 11, 1983.

8. "Proposed Technical Specification Change and Notice Regarding Acceptable Pressure Isolation Valve In-Service Test Leak Rates," Memorandum from Harold R. Denton, Director, Office of NRR, to Victor Stello, Jr., Committee to Review Generic Requirements, USNRC, February 14, 1985.

9. "Minutes of CRGR Meeting Number 79," Memorandum for William J. Dircks, Executive Director for Operations, from Victor Stello, Jr., Chairman, Committee to Review Generic Requirements, August 21, 1985.

10. "Leak Rate Testing - Pressure Isolation Valves," Memorandum from Harold R. Denton, Director, Office of NRR, to James Sniezek, Acting Chairman, Committee for Review of Generic Requirements, USNRC, March 3, 1986.

11. P. Lam, "Overpressurization of Emergency Core Cooling Systems in Boiling Water Reactors," Nuclear Regulatory Commission Office for the Analysis and Evaluation of Operating Data, February 1985.

2. SURVEY OF REPRESENTATIVE BWR PLANTS

Three BWRs were selected for detailed analysis regarding interfacing system LOCA. They are Peach Bottom, Nine Mile Point-2, and Quad Cities. Table 2.1 lists some important characteristics of these plants. Information on the interfacing lines in the selected plants was collected. Appendix A provides information on the lines identified, including valve arrangement, automatic and manual control, and potential indications of overpressurization or LOCA. Section 2.1 describes the method used to identify interfacing lines, and some general observations. Section 2.2 discusses the detailed information that was sought for assessing frequencies of overpressurization, and conditional probability of core damage given an interfacing LOCA.

2.1 Identification of Interfacing Lines in Selected BWRs

Some information on interfacing lines in light water reactors is provided in a study by Oak Ridge National Laboratory.[1] However, because that study was performed in 1981, some of the information may not be up to date. This was pointed out by a recent Event V inspection conducted on all Region I reactors including Peach Bottom.[2] Reference 2 provides some information on interfacing lines at Peach Bottom but not Nine Mile Point-2 or Quad Cities.

Interfacing lines for the selected plants have been identified using their FSARs. Each FSAR has a table of containment isolation valves for all lines penetrating containment. These tables have been incorportated into Appendix A. Some of the lines penetrating containment are not connected to the reactor coolant system, e.g., the RHR containment spray line. Such lines were not analyzed further. The remaining lines are connected to the reactor coolant system and, therefore, at least portions of these lines are rated for high pressure. The piping and instrumentation diagrams (P&ID) and the process diagrams for the corresponding systems were reviewed to determine the high/low pressure interfaces. The following criteria were used to eliminate some lines as being not important or outside the scope of this interfacing system study.

A. <u>High Energy Lines</u> - Lines that are designed for high pressure are not considered further. For example, main steam lines, steam supply lines for RCIC and HPCI turbines, and lines in the reactor water cleanup system.

B. <u>Small Lines</u> - Lines with diameters less than 1-1/2" are not considered. For example, sample lines, control rod drive insert or withdraw lines, and standby liquid control injection lines. Breaks in these lines have not been included because they do not directly impact on the needed safety systems and the resulting leakage is expected to be small.

C. <u>Injection Line of Control Rod Drive Pumps</u> - The system consists of two pumps in parallel, one normally operating, the other normally on standby. The standby pump is isolated from the operating pump by a check valve and a manual valve on the discharge side and a manual valve on the suction side. The discharge side of the system is high pressure and the suction side of the pumps is low pressure. One scenario of an interfacing LOCA is that the discharge valves of the standby pump fail open, back-flow through the pump overpressurizes the pump suction and causes the suction manual valve to rupture. This disturbs the suction side of the operating pump and causes it to trip. At this time, a small LOCA is resulted through the standby pump train. The operator can also isolate this by closing the MOVs in the discharge line. The frequency of such a LOCA is expected to be quite low and even if such a LOCA should occur, the flow would be limited by the size of the smallest pipe section which is typically 1-1/2". Therefore, based upon the ability to isolate, the lack of direct impact on mitigating systems and the limited flow potential, these lines have not been included in the succeeding phases of this study.

D. <u>Lines that are Connected to the Primary Coolant Pressure Boundary Outside the Containment by Normally Closed Pressure Isolation Valves (PIVs)</u> - If the failure of the PIVs in a given line does not result itself in a LOCA, then an additional failure of the containment isolation valves will be needed for an interfacing LOCA to occur. The frequency of such a scenario will be quite low. For example, the feedwater flush line at Peach Bottom is 12" in diameter, and is isolated from the feedwater pressure by

two normally closed valves (PIVs). If the normally closed valves fail open and feedwater pressure causes the flush line to rupture. Feedwater will be diverted through the break. LOCA will not occur unless the feedwater check valve inside the containment fails to close when the main feedwater pump is tripped. If this check valve does fail to close, the control room operator can isolate the MOV downstream of this check valve. Similarly, in the reactor water cleanup system, there are many low presure lines used for backwash and precoat of the filter demineralizer. They are isolated from high pressure piping by two normally closed valves. If the valves fail open and cause a rupture of low pressure piping, the containment isolation valves should isolate the reactor water cleanup system from the primary coolant system. LOCA in these lines then requires failure of two containment isolation valves that are not the PIVs, as well as failure of the two PIVs. Therefore, the frequency of LOCA is again expected to be quite low compared to those lines listed in Table 2.2 which represent the interfacing lines selected by this phase of the study for further analysis.

E. <u>Lines that are not Connected to the Reactor Coolant System Need not be Considered</u> - Some of the lines penetrating containment do not make any connection to the primary system, for example, the drywell purge lines. Such lines could not cause a LOCA upon their failure and thus do not fall within the scope of this study.

All lines penetrating containment and not climinated using the above criteria were analyzed further. P&IDs that show all lines connected to the primary system were also reviewed to be sure no line would be overlooked. The information collected for the identified lines is given in Appendix A. Figures 2.1 and 2.2 are simplified drawings showing major components in the systems that have lines penetrating the containment. Appendix A provides a table which lists lines penetrating containment for each of the three plants in this study. The single character code in the first column of each table denotes the disposition of line. An asterisk indicates that the line is considered within the study. A letter means that the line is not further considered, based upon the screening criterion denoted above by the same letter.

Based on the survey of the three selected BWRs, the following were observed:

- The following systems are high pressure on the discharge side of the pumps, but low pressure on the pump suction sides: Reactor core isolation cooling system (RCIC), high pressure coolant injection system (HPCI), high pressure core spray system (HPCS), control rod drive system, standby liquid control system, and feedwater system.

- The feedwater line is somewhat unique in that the feedwater system is normally operating. The feedwater discharge line is high pressure but the pump suction side is low pressure. The water hammer event at San Onofre-1[3] was caused by common cause failure of multiple check valves. Chapter 3 and Appendix B provide more detail of the incident. If the analogous event had occurred in a BWR, a large interfacing LOCA could have resulted.

- The reactor water cleanup (RWCU) system has a blowdown line downstream of the filter demineralizer. It is connected to the condenser through low pressure piping. The line can be used when reactor is at power. A restricting orifice reduces the pressure before the flow reaches the low pressure piping. Overpressurization or pipe rupture may occur if a valve in the low pressure piping is closed. However, an isolation valve in the line itself is expected to close as a result and further, given its failure, the containment isolation valves will then act to isolate the system. This line is not considered further, because the frequency of unisolated interfacing LOCA in it is judged to be quite low compared to the lines listed in Table 2.2. In addition, as documented in Section 3.1, two separate data searches were undertaken to ascertain if any related failure experience exists for the RWCU systems. Based on these data searches, nothing was found to indicate this system should be included in the ensuing phases of this study.

2.2 Information Collected for Identified Lines

For each of the interfacing lines identified, the following information was collected and documented in Appendix A.

1. Pressure Isolation Valves (PIVs) - These were obtained from the P&IDs of the systems. The list, if available, of PIVs in Technical Specifications is used to check for completeness.

2. Surveillance Requirements for the PIVs and the System Pumps - Most of the PIVs are also containment isolation valves for ECC systems. The tests they may be subjected to are local leak rate test (LLRT) for containment isolation valves, leak rate test for PIVs, and valve operability test for valves in the ECCS.

3. Automatic and Manual Control of PIVs and the System They are In - This is based on P&IDs and system descriptions in FSAR.

4. Valves that Will Bound the Low Pressure Piping that Will be Overpressurized, if the PIVs Fail Open - This is based on P&IDs.

5. Potential Alarms or Indications of Overpressurization or Interfacing LOCA - This is obtained by reviewing system descriptions, P&IDs, process diagrams, functional control diagrams, and system descriptions for leakage detection system, radiation monitoring system, and HVAC for the reactor building.

In addition to the information in Appendix A, attempts were made to collect information needed to assess what effects a postulated interfacing LOCA in the identified lines may have on safety systems that are needed to mitigate the accident. Intersystem effects may be caused by such things as flooding, overpressurization of compartments, high temperature steam damage, drainage of the condensate storage tank or the suppression pool. Typically, different ECC systems are located in different compartments as are pumps in different trains of the same system. The compartments are typically connected by water tight doors. Other potential interconnections include blow-out panels and HVAC

ducts. The compartments are typically designed for an internal to external differential pressure of 0.25 psid. For those compartments that contain high energy lines, blow-out panels are typically installed to relieve any blowdown to additional volumes. "High energy lines" are defined to be lines with operating pressure greater than 275 psig or operating temperature greater than 200°F, e.g., RCIC steam line, main steam lines, and feedwater lines. Typically, the floor of the pump rooms is at the same level as the suppression pool. The suppression pool water level is approximately 20' or more. The suppression pool suctions of ECCS are more than 8' below the normal suppression pool level and the suction piping usually slopes down to the pump, such that the suction piping is always filled with water to provide the needed net positive suction head. If the suction piping is ruptured, loss of suppression pool inventory may be a problem.

To the extent attainable in one-to-two day plant site visits, the above classes of information were persued by plant tour and/or interviews with key plant personnel. The results of these visits played an important role in formulating many of the assumptions found in the following sections of this report. Every attempt has been made to indicate the origin and basis for each such assumption whenever it is introduced.

2.3 References

1. Fred A. Heddleson, "Summary Report on a Survey of Light Water Reactor Safety Systems," Oak Ridge National Laboratory, NUREG/CR-2069, October 1981.

2. "Special Inspections Regarding Potential Intersystem Overpressurization of Emergency Core Cooling Systems (Event V Inspections)," Memorandum from Thomas E. Murley, Regional Administrator, Region I, to James M. Taylor, Director, Office of Inspection and Enforcement, USNRC, September 18, 1985.

3. "Loss of Power and Water Hammer Event at San Onofre Unit 1, on November 21, 1985," USNRC, January 1986.

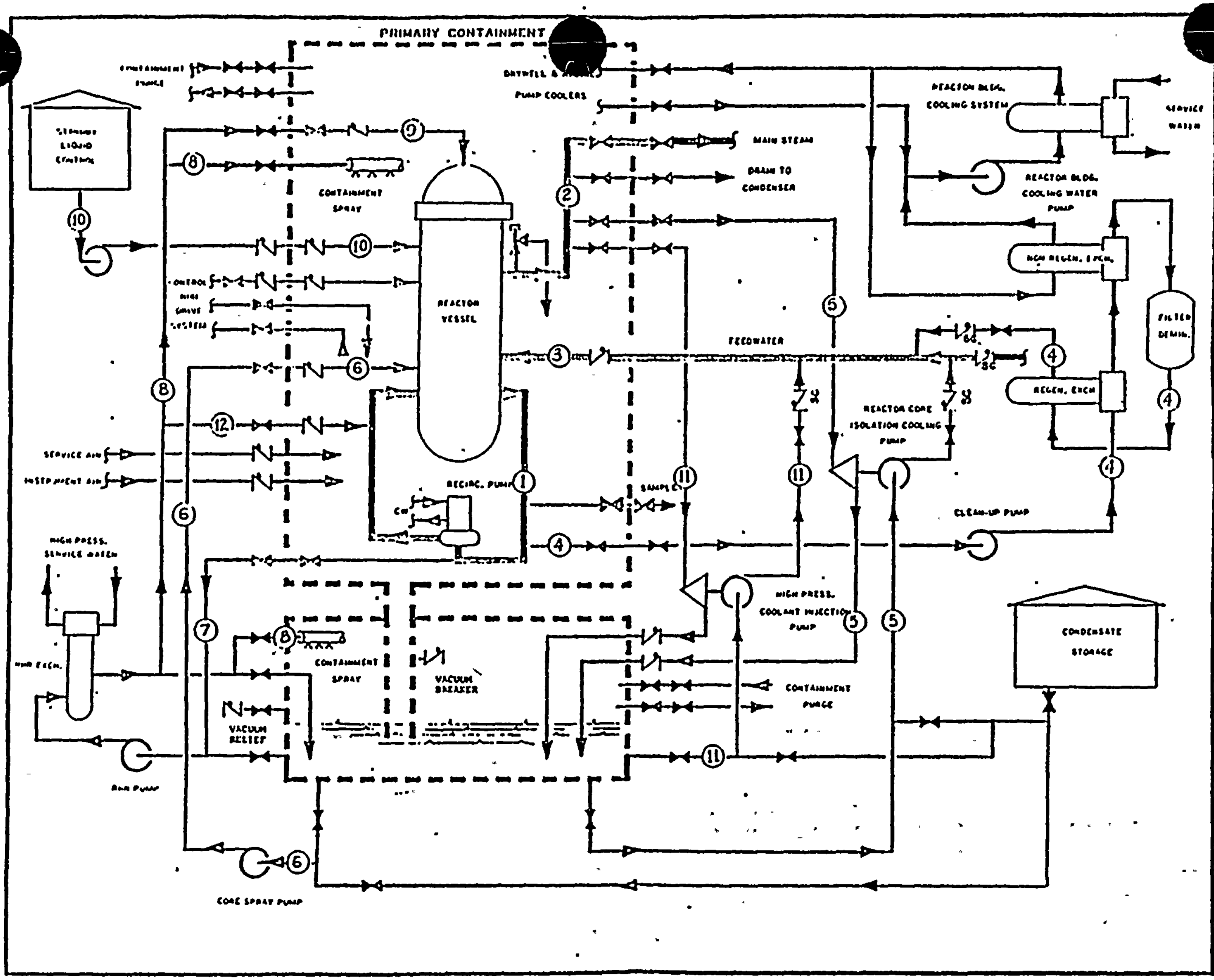

Figure 2.1 A simplified drawing for lines penetrating containment at Peach Bottom.

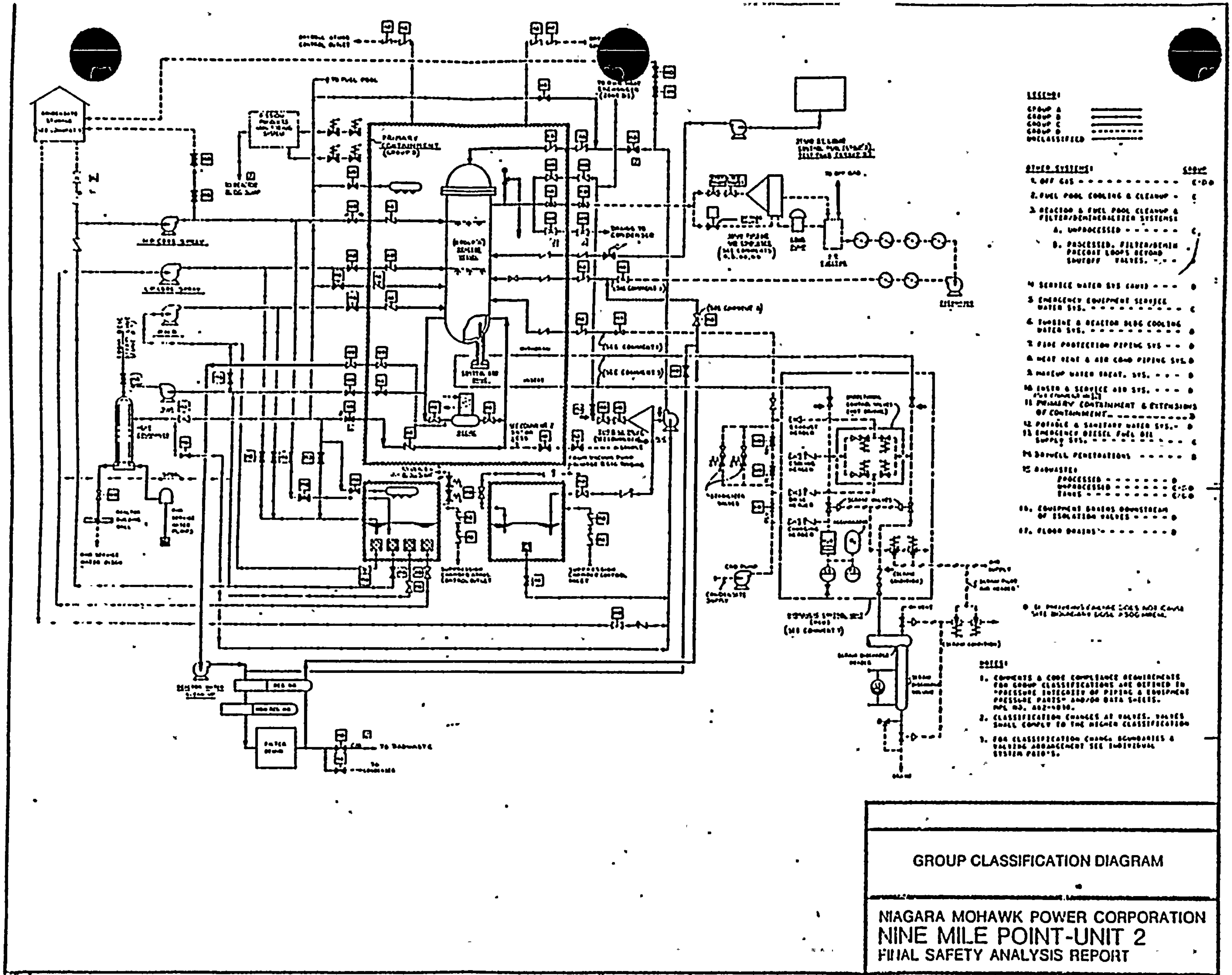

Figure 2.2 A simplified drawing for lines penetrating containment at Nine Mile Point-2.

Table 2.1
Characteristics of Selected BWRs

	Peach Bottom	Nine Mile Point-2	Quad Cities
Containment Type	Mark I	Mark II	Mark I
BWR	4	5	3
AE	Bechtel	Stone & Webster	Sargent & Lundy
Design Power (MWe)	1065	1080	789
RHR			
Heat Exchangers	4	2	2
Pumps	4	3	4
Pumps for Shutdown Cooling Mode	4	2	4
Injection Location	Recirculation Line	Vessel	Recirculation Line
LPCI Containment Penetration	2	3	2
Steam Condensing Line to RHR Heat Exchanger	No	Yes	No
LPCI Discharge Cross Connection	Yes	No	Yes
Service Water Connection	Yes	Yes	No
Fuel Pool Cooling Connection	Yes	Yes	Yes
LPCS			
Pumps	4	1	2
Injection Line	2	1	2
HPCI	Yes	No	Yes
HPCS	No	Yes	No
CST	1 per unit	2	2
RCIC Injection Location	Feedwater Line	Vessel Head	Feedwater Line

Table 2.2
Interfacing Lines Identified for Analysis

<u>Peach Bottom</u>

LPCI Injection Lines
Shutdown Cooling Suction Line
RPV Head Spray
Core Spray Injection Lines
HPCI Pump Suction
RCIC Pump Suction

<u>Nine Mile Point 2</u>

LPCI Injection Lines
Shutdown Cooling Suction Line
RPV Head Spray
Low Pressure Core Spray Injection Lines
HPCS Pump Suction
RCIC Pump Suction
Shutdown Cooling Return to Recirculation
Steam Condensing Supply Line to RHR Heat Exchanger

<u>Quad Cities</u>

LPCI Injection Lines
Shutdown Cooling Suction Line
RPV Head Spray
Core Spray Injection Lines
HPCI Pump Suction
RCIC Pump Suction

3. SURVEY OF OPERATING EXPERIENCE AND IDENTIFICATION OF CAUSES OF FAILURE

3.1 Survey of Operational Events Involving Failures of Pressure Isolation Valves

After the Browns Ferry-1 event on August 14, 1984,[1-2-3] AEOD looked at operating experience dating back to 1975 to identify events involving actual and potential overpressurizations of emergency core cooling systems.[1] The scope of the search included all emergency core cooling systems as well as the reactor core isolation cooling system in BWRs. Eight incidents were identified. A summary of the events is provided in Table 3.1.

To expand the search for operational events involving pressure isolation valve (PIV) failures, BNL performed the following searches using the RECON[4] data base.

- A search for valve failures in ECCS systems and RWCU system was done on February 14, 1986 for events reported in the 1981 to 1986 period.
- A search for valve failures in ECCS systems and RWCU system was done for events reported before 1975.
- A search for check valve failures in feedwater systems of both PWRs and BWRs was done on April 20, 1986.

The search for failures of feedwater check valves was performed to identify any failures similar to the San Onofre-1 event,[5] in which 5 check valves in the feedwater lines failed open, resulting in a water hammer, and severe damage to the feedwater piping and supports.

The RECON data base provides a one line description and an abstract for each identified event. First, the one line descriptions were reviewed. Those events involving valves that are not pressure isolation valves were skipped. The abstracts of the remaining events were then reviewed. A few incidents involving failures of pressure isolation valves to pass local leak rate tests were found. They all involved very small leakage and were not considered further, except the event at Susquehanna-2.[6] This event involved multiple failures of pressure isolation valves in the RHR system such that pressure at

the RHR heat exchanger was increasing. The plant was forced to shutdown in order to repair the failed valves. Table 3.2 provides a summary of the eleven incidents that have been identified and incorporated into this study. They are ordered in chronological order.

Appendix B provides detailed descriptions and associated valve arrangements of these events. Eight of the eleven incidents were identified by AEOD.[1] Their descriptions were taken from Ref. 1. The description for the Susquehanna-2 incident was taken from the LER.[6] The description of the Pilgrim incident in April 1986 was taken from Ref. 7. (It is interesting to note that Pilgrim replaced its air operated check valves by regular check valves after the event on September 29, 1983[8] and, therefore, this recent incident involves failure of a regular check valve.) The San Onofre-1 incident[5] is included in the list, because if an analogous incident had happened in a BWR, a large LOCA outside the containment could have resulted.

3.2 Identification of Causes of Failures and Methods of Discovery

In this section, the valve failures in the incidents identified are described. The causes of failures are discussed if identified. Also provided are the ways the failures were discovered. This information was collected from references listed in Table 3.2.

3.2.1 Events Involving Failure of Testable Check Valves

The first nine incidents of Table 3.2 involve failures of testable check valves. In these incidents, testable check valves are used inside the drywell in the injection lines of ECCSs of BWRs. Along with a normally closed MOV outside the drywell, the testable check valve serves as both containment isolation valve and pressure isolation valve. Technical Specification testing requirements for these valves are given in the tables of Appendix A. Figure 3.1 shows the structure of a testable check valve.[15-16] It has an air operator controlled by a solenoid pilot valve. It also has a bypass valve that is needed to cycle the testable check valve when the reactor is pressurized.

In this section, some descriptions of the operation of the testable check valves are provided. The causes of failures are discussed in Subsections 3.2.1.1 through 3.2.1.9.

The following description of testable check valves made by Rockwell International has been taken from Ref. 15, and applies to the testable check valves at Hatch 2. Testable check valves at other plants may be made by manufacturers other than Rockwell International, therefore, their detailed design may be different.

> Prior to a test opening via the air actuator, the bypass valve on the 1" line around the check valve is opened to equalize the pressure on both sides of the disk of the check valve. When the remote test push button is depressed, power is supplied to the solenoid pilot valve causing the pilot valve to shift. This in turn causes the actuator rod to rotate from its neutral position. When the actuator rod reaches its 150° position, it engages the check valve disk via a disk pin. Further rotation of the actuator rod lifts the disk from the valve seat. The actuator rod will rotate another 30° to its 180° position where it will stop. The limit switch on the actuator gives an indication of actuator travel (the full 180° from neutral) via a light on the control panel in the control room. A proximity switch tripped by a ferrous cam connected to the valve disk gives an indication of disk position (open) via another light on a control panel in the control room. The isolation check valve which provides the first of two isolation boundaries between the RCS and the RHR system is a safety-related component, while its air actuator and the pilot solenoid valve are not classified as safety-related.

The following description of testable check valves made by Anchor Darling has been taken from Ref. 12, and applies to the valves at LaSalle-1.

> The Testable Check Valve is exercised open by first opening the Testable Check Bypass Valve. This is done to equalize pressure across the check valve disc. The Testable Check Valve is then cycled open by operating a remote handswitch. This handswitch energizes a solenoid valve, opening it and causing the following to happen.

Instrument air is supplied to one side of an air piston cylinder which moves a rack and gear assembly against spring tension. This movement of the rack and gear assembly rotates a lobed shaft connected through the gear approximately 25° contacting the valve disc and lifting it off its seat. When the handswitch is returned to close, the solenoid valve de-energizes closed securing instrument air to the air piston. Spring tension returns the rack and gear assembly to its normal position. This rotates the lobed shaft connected through the gear away from the disc allowing the disc to close due to it's own weight and differential pressure.

3.2.1.1 Vermont Yankee Event on December 12, 1975

In this incident, testable check valve 10-46A was leaking past its seat, while the indicator lights in the control room showed that the valve was fully closed. The failure was discovered because of the subsequent overpressurization of the low pressure piping. The cause of failure has not been reported.

MOV 10-25A initially failed to open during the valve operability test. It was manually opened. Then the valve was successfully cycled. The cause was reported to be excessive differential pressure across the valve seat resulting from the leakage through the testable check valve. This is judged not to be the only cause, because if check valve leakage always lead to failure of the upstream MOV, then experience would so indicate.

MOV 10-27A is normally open. During the incident, it was closed according to procedure before MOV 10-25A was opened. However, it failed to close fully, leaving an 1" opening. The indication in the control room for this valve falsely indicated that it was closed. The causes of the valve failure and the false indications were not reported. The failures were discovered because of the overpressurization. As the result of overpressurization, the RHR heat exchanger developed a leaking gasket on the fixed tube sheet to shell flange. A steam water mixture was discharged from the flange area and three RHR system relief valves.

3.2.1.2 Cooper Event on January 21, 1977

In this incident, HPCI the testable check valve, AO-18, failed to remain fully closed, due to a broken sample probe wedged under the edge of the valve disc. The sample probe came from the main feedwater line upstream from where the HPCI discharges into the feedwater line. In order for the broken sample probe to get to the as-found position, the check valve disc must have been lifted from the valve seat. One possibility is that the check valve first leaked, and the piping between the check valve and the MOV, MO-19, was pressurized. With the pressure across the check valve disc equalized, the valve disc rattled due to vibration in the feedwater line. This failure was not recognized until the backflow of feedwater to the HPCI pump suction occurred. It was not known if the position indication in the control room was indicating correctly.

With the testable check valve partially open, the outboard isolation valve MO-19 was opened as required by the HPCI System Turbine Trip and Initiation Logic Surveillance Test. This resulted in backflow of feedwater to the pump suction piping. The isolation valve was then closed. It was not reported whether or not overpressurization of low pressure piping took place.

If the low pressure piping was overpressurized to the point that it ruptured, diversion of feedwater and unavailability of HPCI would have resulted. An interfacing LOCA will not result unless the feedwater check valve inside the drywell also fails in an open position upon feedwater trip.

3.2.1.3 LaSalle-1 Event on October 5, 1982

In this incident, a testable check valve was tested by cycling while the plant was operating at 20% power. This was done by first opening the bypass valve to equalize the pressure on both sides of the valve disc, and then operating a remote hand switch. A more detailed description of this operation has already been discussed in Section 3.2. After the test, both the testable check valve and its bypass valve failed to indicate closed. The testable check valve was found to be 5% open.

Normally, the preload on the actuator spring will return the actuator cylinder to its normal position after air pressure is removed. The check valve disc will then close by its own weight and pressure differential. The failure of the testable check valve to reseat was caused by some combination of the following. The lubricant on the actuator cylinder was dry, making it difficult for the cylinder to move. The preload on the spring was not sufficient to return the cylinder to its normal position. And, the bypass valve stayed open, keeping the pressure equalized across the check valve disc. The cause of the bypass valve failure was not reported.

3.2.1.4 LaSalle-1 Event on June 17, 1983

Similar to the LaSalle-1 event on October 5, 1982, a testable check valve and its bypass valve failed to indicate closed after being opened by test. The cause of the check valve failure was found to be a stuck open bypass valve and possibly thermal binding of the check valve disc. The cause of the bypass valve failure was not reported. During shutdown of the plant, the bypass valve closed unassisted as reactor temperature and pressure decreased. This then allowed the testable check valve to close. The valve was examined and anadjustment to spring tension was made. A concern was raised that the check valve and its bypass valve tend to remain partially open after being cycled hot. A revision to the in-service-test of pumps and valves was proposed to test the valve in cold shutdown only.

3.2.1.5 LaSalle-1 Event on September 14, 1983

In this event, the testable check valve in the LPCI line failed open, resulting in draining of reactor coolant while performing RHR System Relay Logic Test at cold shutdown. The operator was immediately aware of a reactor water level decrease and secured the flow path by closing the injection valve that was opened during the test. The valve failure was due to two causes, misalignment of the interfacing gears between the check valve and the air operator, and tightness of the packing gland on the check valve shaft inhibiting free movement of the valve disk. Both causes were due to maintenance errors. The interfacing gear has a timing mark used to align the gears for proper reassembly after maintenance. The timing mark on the spline shaft of the check valve was

confused with a score mark on the spline shaft. This aligned the check valve and the air operator such that the check valve was 35° open when the air operator was in the fully closed position. The packing gland was adjusted too tight in the preceding maintenance of the valve. The local leak rate test that was required after maintenance was inadvertently not performed. Otherwise, this problem would have been discovered and corrected.

3.2.1.6 Pilgrim-1 Event on September 29, 1983

In this incident, the HPCI testable check valve was partially open, and both HPCI pump discharge valves were inadvertently opened by the operator. The HPCI pump suction was overpressurized by the feedwater system pressure. The overpressurization caused the gland seal condenser gasket to rupture. This in turn caused a mixture of water and steam to spray from the condenser to a nearby limit switch resulting in a 250-V dc battery ground, and a large amount of water in the pump room. The operator relieved the pressure by opening valves in the HPCI test return line at one minute into the incident.

The exact cause of the check valve failure was not determined. There was some evidence that a rusted linkage between the valve stem and the attached air operator had contributed to the failure. The rusted linkage was repaired and the check valve was returned to its correct position. In the short term, the testable check valve was tested by monitoring the pressure in the pipe section between the check valve and the outboard discharge valve. After 16 hours no pressure buildup was detected. In the long term, the testable check valve will be replaced by a new design. Both discharge valves were opened at the same time. This was due to verbal miscommunication between the control room operator and an I&C technician.

The error consisted of conducting two surveillance tests "HPCI Steam Supply Isolation Valve Logic" and "HPCI Injection Valve Logic," at the same time, and not ensuring that test prerequisites and initial test conditions for all steps in the test procedures were met.

3.2.1.7 Hatch-2 Event on October 28, 1983

In this incident, the testable check valve in the LPCI line was found open during valve operability test for the RHR system. The failure was due to a maintenance error committed more than four months previously, on June 7, 1983. After that maintenance, the two air supply lines from the solenoid operated valve to the air actuator were reversed. This failure was mainly attributed to the failure to use the valve maintenance manual which was not available at the time. The error was not discovered by post-maintenance testing which was either missed or not correctly done. During the four month period, the reactor was operating at substantial power levels. The open check valve went undetected by plant personnel even though valve position and actuator travel indications were provided in the control room. This lack of detection is attributed to also reversing the electrical leads such that the indication in the control room indicated the valve was closed.

3.2.1.8 Susquehanna Event on May 28, 1984

The incident started with duel indication (i.e., both "open" and "closed" indicating lights illuminated) for the testable check valve and its bypass valve in the LPCI line. The inboard injection valve was in its normally closed position. Later, the outboard injection valve was closed, and the inboard injection valve was cycled in an attempt to seal the testable check valve. When the outboard injection valve was reopened, pressure at the primary side of the RHR heat exchanger was observed to be increasing and the outboard injection valve was closed again.

The only problem reported for the testable check valve was dual indication. It was attributed to a loose diaphragm plate connector that resulted in improper contact with the limit switches in the bypass valve. The plate connector and its set screw were tightened. No other failure modes of the testable check valve were reported. Since the pressure at the RHR heat exchanger was increasing, some leakage through the check valve or its bypass valve must have occurred.

The inboard injection valve failed to fully close after being cycled. It was found that the valve disk would not center on its seat due to the dimensions of the disk guide bearing surface. This resulted in the valve sitting low in the body. Due to machining tolerance during manufacturing, the disk would not seat in the same location each time it was stroked. The seat was lapped and its lower disc guide bearing surface was built up 1/4".

3.2.1.9 Browns Ferry-1 Event on August 14, 1984

In this incident, the testable check valve failed open due to maintenance error, and the injection valve was opened inadvertently during the Core Spray System Logic Test. As a result of these failures, low pressure piping and equipment were overpressurized for 13 minutes before the operators reclosed the injection valve.

The check valve failure was caused by maintenance error in installing a plunger with reversed air ports in the actuator pilot solenoid valve. Maintenance records indicated that the valve was held open from December 1983. The valve misposition was not detected because the position indication was also reversed following the maintenance such that the valve misposition was not evident.

The injection valve was opened due to operator failure to follow the test procedures. The procedures specified that the valve motor operator circuit breaker should be racked-out so that the valve would have no motive power and would remain closed during the logic test. However, the operator failed to rack-out the breaker. Thus, when test signal was applied during the logic test, the injection valve opened.

3.2.2 Events Involving Failure of Swing Check Valves

The last two incidents in Table 3.2 involve failure of check valves that are not testable. Figure 3.2 shows the structure of a swing check valve. In the Pilgrim incident, the check valve is used as a containment isolation valve inside the drywell for the LPCI line. In the San Onofre incident, check valves

are used on the discharge side of the feedwater pumps and downstream of the feedwater regulating valves.

3.2.2.1 San Onofre Event on November 21, 1985

In this incident, five check valves failed open, namely, the discharge check valves of two feedwater pumps, and the check valves downstream of the feedwater regulating valves for the three steam generators. When ac power to one feedwater pump was lost, feedwater from the other feedwater pump backflowed through the failed open discharge check valve to the suction side of the pump, and caused the flash evaporator to rupture. Due to failures of the check valves, three steam generators were blown down through the ruptured flash evaporator. Following the emergency procedures, the operators isolated the feedwater lines. As the auxiliary feedwater system started to fill the emptied feedwater lines, a water hammer occurred and caused a crack on the feedwater line and multiple failures of pipe supports. Throughout the incident, the primary coolant inventory was maintained with charging pumps, and was properly cooled.

The failure modes of the check valves are very similar. Either the disc was separated from the hinge arm or the disc nut was loose. There was evidence indicating that these failures existed over an extended period of time, for example, worn hinge pin hole, damaged disc stud, and scratch marks at the bottom. The cause of failure was attributed to inadequate design, and flow induced vibrations. Check valve failures caused by partial disassembly while in service do not appear to be unique to San Onofre-1.

According to the ASME Boiler and Pressure Vessel Code, Section XI, the feedwater check valves should be tested every cold shutdown if three months has passed since the last test. Records indicated that the feedwater pump discharge check valves were last tested in November 1984, and the feedwater regulating check valves were last tested in February 1985. There were three cold shutdowns between February 1985 and November 21, 1985 when the incident occurred. The check valves were not tested as required during those shutdowns. Otherwise, the failures might have been discovered before the transient occurred.

Table 3.3 lists the incidents of failures of feedwater check valves that were identified by LER search[4] and review of Nuclear Power Experience[19] (NPE). Only those failures that are similar to the failures at San Onofre-1 are listed.

3.2.2.2 Pilgrim-1 Event on February 12, 1986 and April 11, 1986

In the incident on February 12, 1986 both the testable check valve and the normally closed LPCI outboard injection valve leaked, resulting in high pressure alarms. The alarms occurred repeatedly in the few weeks before this date. Operators simply vented the piping after each alarm. On this date, the outboard injection valve was manually tightened, and its torque switch was replaced and reset. Also, the inboard injection valve was closed. The plant continued power operation until April 11, 1986, when more high pressure alarms occurred. The outboard injection valve started leaking. The plant was shutdown. The cause of failures was not reported.

3.3 References

1. P. Lam, "Overpressurization of Emergency Core Cooling Systems in Boiling Water Reactors," Nuclear Regulatory Commission Office for the Analyses and Evaluation of Operating Data, February 1985.

2. "Trip to Browns Ferry Unit 1 Regarding Potential Core Spray Overpressurization," Memorandum from Scott Newberry to Barry Holahan, Operating Reactors Assessment Branch, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, September 29, 1984.

3. "Overpressurization of Core Spray Piping," LER 84-032, Browns Ferry Unit 1, September 13, 1984.

4. DOE/RECON, Nuclear Safety Information Center (NSIC), File 8, 1963 to present.

5. "Loss of Power and Water Hammer Event at San Onofre Unit 1, November 21, 1985," NUREG-1190, U.S. Nuclear Regulatory Commission, January 1986.

6. "Reactor Shutdown due to Inoperability of the 'B' Loop of Low Pressure Core Injection," LER 84-006, Susquehanna Unit 2, June 27, 1984.

7. "Recent Events at Pilgrim,". Memorandum from Edward L. Jordon, Director of Emergency Preparedness and Engineering Response, Office of Inspection and Enforcement, to Robert M. Benero, Director Division of Boiling Water Reactor Licensing, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, May 1986.

8. "HPCI System Inoperable," LER 83-048, Pilgrim Unit 1, October 14, 1983.

9. "Overpressurization of LPCI Piping," LER 75-24, Vermont Yankee, Vermont Yankee Nuclear Power Corporation, January 8, 1976.

10. "Abnormal Degradation of the Primary Containment Boundary, LER 77-04, Cooper, Nebraska Public Power District, February 4, 1977.

11. "HPCS Testable Check Valve Failure," LER 82-115, LaSalle Unit 1, Commonwealth Edison, November 3, 1982.

12. "HPCS Testable Check Valve Failure to Close," LER 82-066, LaSalle Unit 1, Commonwealth Edison, July 15, 1983.

13. "Inadvertent Draining of RCS Water," LER 83-105, LaSalle Unit 1, Commonwealth Edison, September 27, 1983.

14. "Overpressurization of HPCI Piping," LER 83-048, Pilgrim Unit 1, Boston Edison Company, September 30, 1983.

15. "Stuck Open Isolation Check Valve on the Residual Heat Removal System at Hatch Unit 2," AEOD/E414, U.S. Nuclear Regulatory Commission, May 31, 1984.

16. Licensee Event Report 83-112/03L-0, Hatch Unit 2, Docket 50-366, Georgia Power Company, November 17, 1983.

17. "High Pressure Alarm in LPCI Line," Preliminary Notification of Occurrence, Pilgrim, April 11, 1986.

18. "Reactor Tripped due to Loss of Power to Safety Related Buses," LER-85-17-1, San Onofre-1, November 21, 1985.

19. S. M. Stroller Corporation, Nuclear Power Experience, updated monthly.

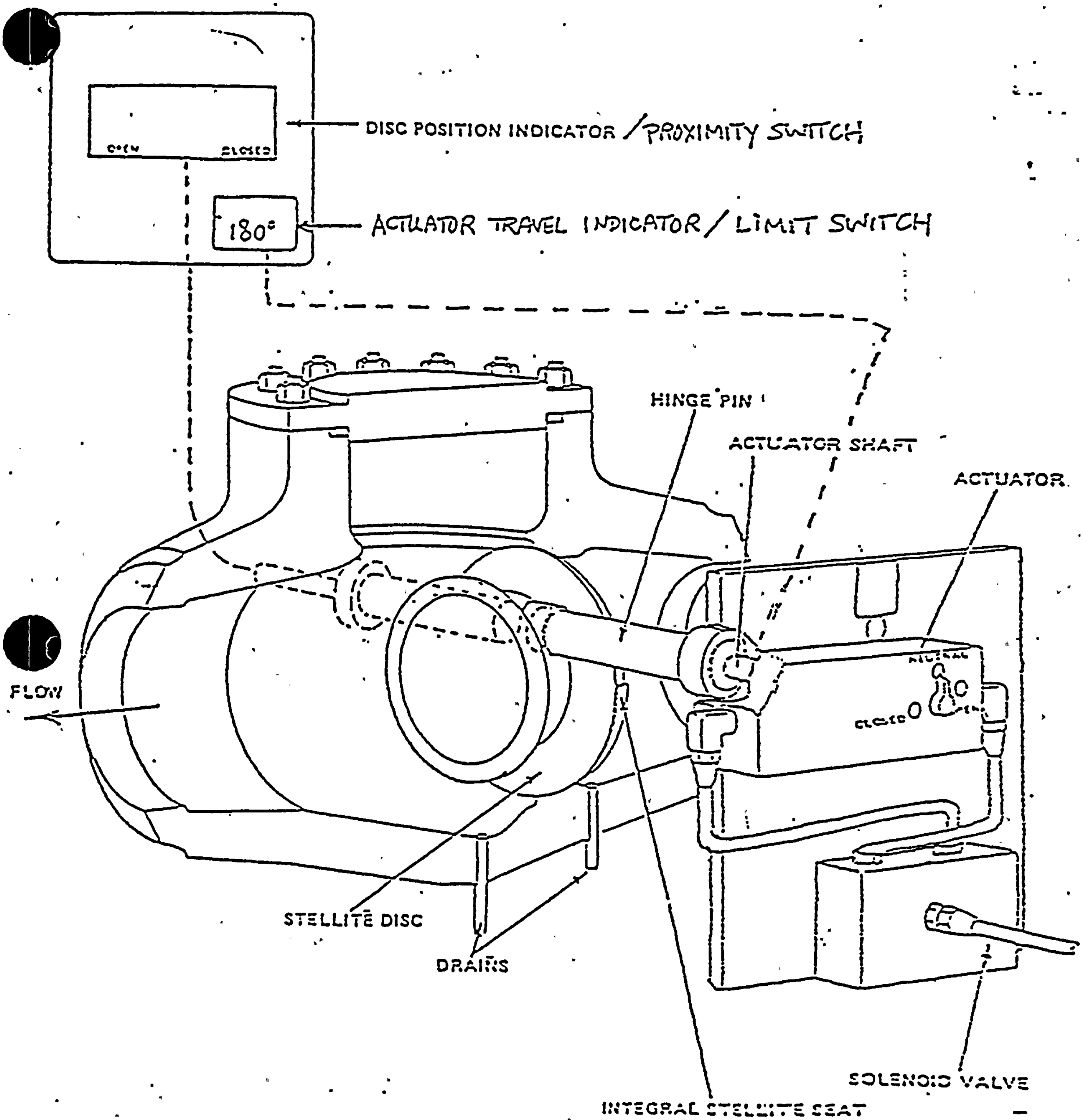

Figure 3.1 Testable check valve.

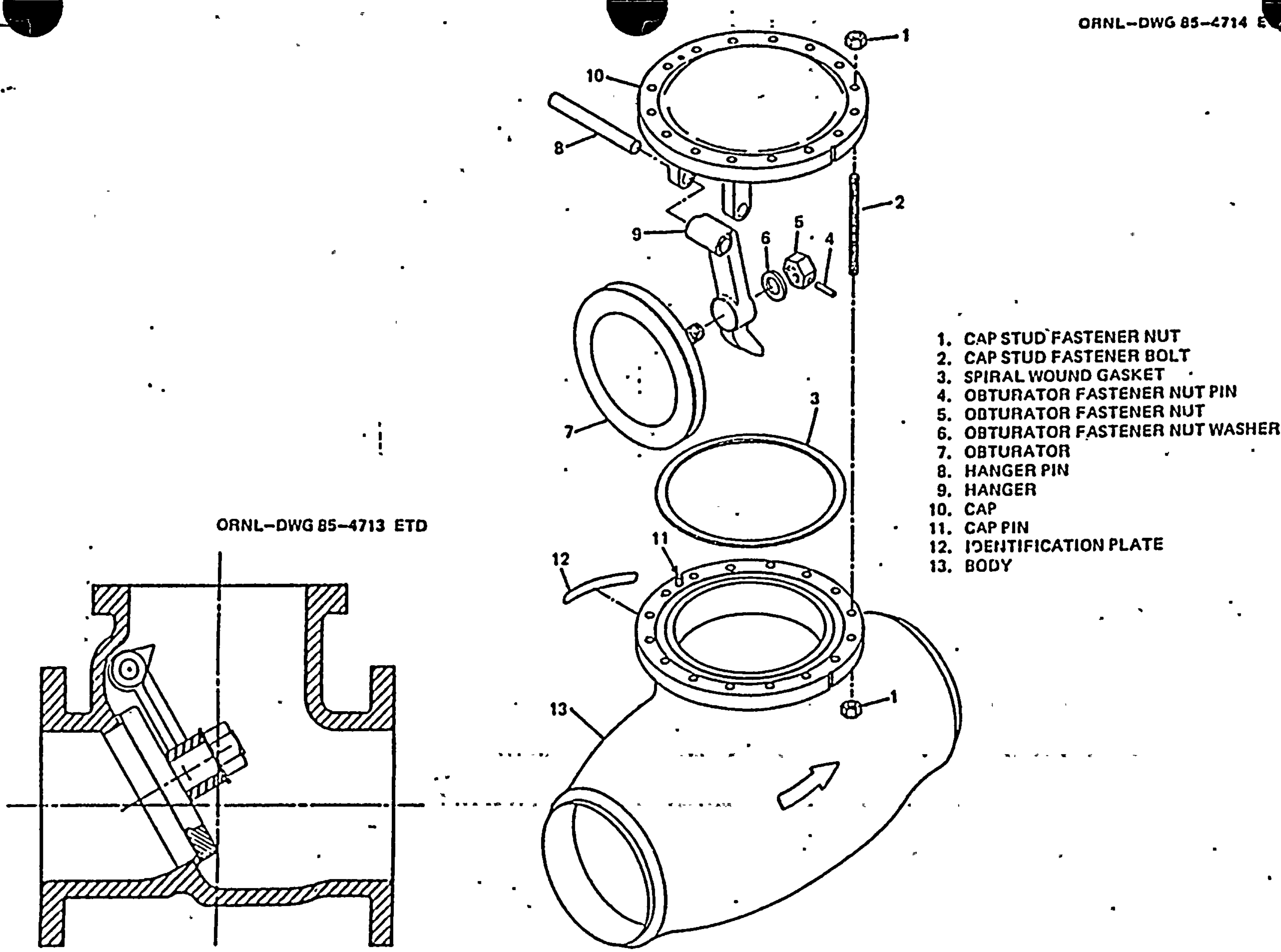

Figure 3.2 Swing check valve.

3.1
Summary of Operating Events Identified in Reference 1

Plant	Event Date	Percent Power	System Involved	Testable Isolation Check Valve		Normally Closed Injection Valve		Overpressurization
				Status	Cause	Status	Cause	
Vermont Yankee LER 75-24	12/12/75	99	LPCI/RHR	Open	Unknown	Intentional but In-appropriate opening	Monthly Testing of LPCI	Yes
Cooper LER 77-04	01/21/77	97	HPCI	Open	Loose Part Obstruction	Inadvertent Opening	Personnel Errors During HPCI Function-al Test	Yes
LaSalle-1 LER 82-115	10/05/82	20	HPCS	Open	Dried Lubricant and Insufficient Preload in Air Operator; Opened Bypass Line	Closed	---	No
LaSalle-1 LER 83-066/03L	06/17/83	48	HPCS	Open	Thermal Binding; Opened Bypass Line	Closed	---	No
LaSalle-1 LER 83-105/01T	09/14/83	0	LPCI	Open	Maintenance Errors	Intentional but In-appropriate Opening	RHR Relay Logic Testing	No, but drained 5,000 Gallons of RCS Water
Pilgrim LER 83-48	09/29/83	98	HPCI	Open	Rusted Linkage on Air Operator	Inadvertent Opening	Personnel Errors in HPCI Logic Testing	Yes
Hatch-2 LER 83-112/03L	10/28/83	0	LPCI	Open	Maintenance Errors on Air Operator	Closed	---	No
Browns Ferry 1 LER 84-032	08/14/84	100	LPCS	Open	Maintenance Errors on Air Operator	Inadvertent Opening	Personnel Errors in LPCS Logic Testing	Yes

Table 3.2

Summary of Operating Events

Plant	Event Date	Percent Power	System Involved	Isolation Check Valve		Inboard Injection Valve		Overpressurization
				Status	Cause	Status	Cause	
Vermont Yankee LER 75-24	12/12/75	99	LPCI/RHR	*	Unknown	Intentional but In-appropriate opening	Monthly Testing of LPCI	Yes
Cooper LER 77-04	01/21/77	97	HPCI	Open	Loose Part Obstruction	Inadvertent Opening	Personnel Errors During HPCI Function-al Test	Yes
LaSalle-1 LER 82-115	10/05/82	20	HPCS	**	Dried Lubricant and Insufficient Preload in Air Operator; Opened Bypass Line	Closed	---	No
LaSalle-1 LER 83-066/03L	06/17/83	48	HPCS	**	Thermal Binding; Opened Bypass Line	Closed	---	No
LaSalle-1 LER 83-105/01T	09/14/83	0	LPCI	Open	Maintenance Errors	Intentional but In-appropriate Opening	RHR Relay Logic Testing	No, but drained 5,000 Gallons of RCS Water
Pilgrim-1 LER 83-48	09/29/83	98	HPCI	Open	Rusted Linkage on Air Operator	Inadvertent Opening	Personnel Errors in HPCI Logic Testing	Yes
Hatch-2 LER 83-112/03L	10/28/83	0	LPCI	Open	Maintenance Errors on Air Operator	Closed	---	No
Susquehanna-2 LER 84-006	05/28/84	2	LPCI	Leaked	Unknown	Leaked	Disc Failure to Seat	Pressure was Increas-ing
Browns Ferry 1 LER 84-032	08/14/84	100	LPCS	Open	Maintenance Errors on Air Operator	Inadvertent Opening	Personnel Errors in LPCS Logic Testing	Yes
San Onofre	11/21/85	60	MFW	Open		Open		Yes
Pilgrim	02/12/86	100	LPCI	Leaked	Unknown	Open	---	Yes

*Did not seat properly.
**Failed to reseat after test.

Table 3.2 (Continued)

Plant	Event Date	Percent Power	System Involved	Outboard Injection Valve Status	Outboard Injection Valve Cause	Related Surveillance	References
Vermont Yankee LER 75-24	12/12/75	99	LPCI/RHR	Closed but	Unknown	Valve Operability Test	1,9
Cooper LER 77-04	01/21/77	97	HPCI	Open	---	HPCI System Turbine Trip and Initiation Logic Surveillance Test	1,10
LaSalle-1 LER 82-115	10/05/82	20	HPCS	---	---	HPCS System Quarterly Surveillance AO Check Valve Cycling	1,11
LaSalle-1 LER 83-066/03L	06/17/83	48	HPCS	---	---	HPCS System Quarterly Operating Surveillance	1,12
LaSalle-1 LER 83-105/01T	09/14/83	0	LPCI	---	---	RHR System Relay Logic Test	1,13
Pilgrim-1 LER 83-48	09/29/83	98	HPCI	Open	Personnel Error in Testing	HPCI Injection Valve Logic, HPCI Steam Supply Isolation Valve Logic	1,14
Hatch-2 LER 83-112/03L	10/28/83	0	LPCI	---	---	RHR Valve Operability	1,15,16
Susquehanna-2 LER 84-006	05/28/84	2	LPCI	Open	---	---	1-3
Browns Ferry 1 LER 84-032	08/14/84	100	LPCS	Open	---	Core Spray Logic Test	1,6
San Onofre	11/21/85	60	MFW	---	---	---	5,18
Pilgrim	02/12/86	100	LPCI	Leaked	Unknown	---	1,7,17

Table 3.3
Failures of Check Valves in Feedwater Systems

Plant	Date	Failure Mode	Source
Crystal River 3	April 5, 1980	Missing Disc Retainer Pin	LER 80-017
Surry 1	April 17, 1980	Dics Detached	LER 80-023
Crystal River 3	May 6, 1980	Missing Hinge Pin	LER 80-021
Turkey Point 3	April 1, 1981	Missing Disc Stud Nut Missing Pivot Pins	LER 81-007
Turkey Point 4	June 8, 1982	Missing Disc Stud Nut	LER 81-008
LaSalle 1	October 4, 1984	Hinge Pin Busing Moved Out of Disc	LER 84-064
Quad Cities 2	March 18, 1985	Missing Hinge Pin	NPE B.14.A.161
Brunswick 2	June 18, 1986	Loose Disc Pivot Pin	LER 86-017

4. ASSESSMENT OF CORE DAMAGE FREQUENCY DUE TO INTERSYSTEM LOCA IN REPRESENTATIVE BWR PLANTS

This section presents the quantification of the frequency of overpressurization in each of the interfacing lines identified in the analysis documented in Section 2, and the frequency of core damage as a result of the overpressurization. The frequency of overpressurization in ECCS injection lines is basically estimated based on the operating event experience and data searches identified in Section 3. Quantification of these events is addressed in Appendix D and summarized in Table 4.1. In each of the operating event incidents, either one or two pressure isolation valves (PIVs) failed. The failure modes and the causes of failures are discussed in Section 3 and Appendix B. Whether or not each identified failure can happen in the interfacing lines of this study is specifically considered, taking into account the specific valve arrangement and the test requirements/procedures for each line. If a similar failure mode is judged to be credible, then the operating event experience is used to estimate the frequency of failure. When any of the operating event experience is judged not to apply to a given interfacing line, the failure data from Table 4.1 is used to asses the frequencies of different combinations of PIV failure modes that will lead to overpressurization.

Given that a segment of low pressure piping is overpressurized, then the possibility that a rupture could occur is considered. Figure 4.1 illustrates the event tree used to determine the conditional probability of various sized LOCAs given that the low pressure piping has been overpressurized. The probabilities in the figure apply to the LPCI line at Peach Bottom with the PIVs failed in a Browns Ferry like scenario. Appendix A identifies the valves that define the boundary of the pipe sections that could be overpressurized. Based upon layout drawing reviews and site visits, most of the valves and other components that could be overpressurized are located in the various pump rooms. The pressure isolation valves are located close to the drywell. Between the PIVs and the pump room is simply pipe runs. The relative vulnerabilities of equipment have been assumed to be pump seals, heat exchangers, and then pipe welds with the lowest failure probability. Therefore, the most likely locations of a rupture or leakage would be in the pump rooms.

The BWR Owner's Group estimated[1] the conditional probability for BWR ECCS pressure boundary rupture during an overpressurization event to be 3.0×10^{-5} due to pipe weld failure. BNL was not chartered with verifying this failure probability nor with doing an independent analysis. Therefore, sensitivity calculations were performed using a range of three values for probability of rupture; 10^{-1}, 10^{-3}, and 3.0×10^{-5}. Given that the BWR Owners' Group work was focused on pipe welds, it is believed to provide a lower bound for the various ruptures that may occur as discussed above. The upper bound for the rupture failure probability was chosen simply to provide a conservative estimate in the expectation that this would bound the actual failure probabilities.

Given a rupture of low pressure piping, blowdown of reactor coolant will start. Depending on the initiating failure modes of the PIVs, the blowdown may be able to be terminated without significant loss of reactor coolant inventory. For example, if the testable check valve has been held open due to the reversal of its air supply to the valve operator, the blowdown flow should cause the check valve to close. This is the case because the air operators are deliberately designed with insufficient torque to move the valve open given differential pressure across the valve. A failure probability of 0.01 has therefore been assumed for the check valve failure to reclose to account for the possibility that it may be damaged when the disk impacts the seat at high speed. Once a blowdown has started, manual isolation using motor-operated valves in the line blowing down is not considered credible, because little time is available and the MOVs are not designed to operate under blowdown conditions. Given that the blowdown is not isolated, it is assumed that core damage will result due to structural failure, flooding ECCS equipment, and/or draining of the suppression pool. This results in sequence 4 in Figure 4.1. The pump rooms are designed for 0.25 psi pressure differential between the inside and the outside. The ventilation openings for the pump rooms may not be large enough to rapidly relieve the overpressurization resulting from the blowdown. Structural failure increases the possible impacts of flooding on systems needed to mitigate the accident. If the break location is at a low elevation, the suppression pool may also be drained.

If no rupture occurs in the overpressurized pipe section, a small loss of coolant accident is assumed to occur, resulting from open relief valves and

failure of gaskets. This results in sequence 1 or 2 in Figure 4.1, depending on the operator's ability to isolation the line. In most cases, such small LOCAs can be isolated with the PIVs in the line. The time available for the operator to isolate a small LOCA is estimated to be more than 30 minutes based upon core uncovery (Ref. 2). Figure 4.2 taken from Ref. 3 shows some time curves for operator actions. The curve for the NREP cognitive error is used to assess the probability that the operators fail to isolate the small LOCA. It is approximately 10^{-2} at 30 minutes. If the break is not isolated, the small LOCA event tree in Figure 4.3 is used to assess the conditional probability of core damage. This event tree is a modified version of the small LOCA event tree in Ref. 4. The probabilities used in the figure apply to a small LOCA in the RHR room of Peach Bottom.

Basically, the small LOCA event tree in Figure 4.3 examines the systems that can be used to provide makeup to the reactor. First, high head systems are considered. If at least one high head system is available, the operators need to depressurize to reduce the flow through the break and use the low pressure systems to provide coolant makeup. If no high head system is available, the automatic depressurization system should depressurize the system, or the operators need to manually depressurize the system, so that low pressure systems can be used. It is assumed that the ECCS injection loop in which the small LOCA occurs is unavailable.

The pump rooms are water tight up to approximately 20 feet above the floor and are equipped with floor drains or floor drain pumps. For the RHR pump room at Peach Bottom, it is estimated that it will take approximately two hours for a small LOCA with a leakage rate of 600 gpm to fill the room to the level of the ventilation openings. Therefore, it will be more than two hours before the flooding encroaches upon other ECCS areas. By then, the reactor should have been depressurized. Appendix A lists various indications of interfacing LOCA available to the operators. If they recognize that an interfacing LOCA has taken place, they will depressurize the primary coolant system to reduce the leakage and to preserve sources of makeup to the primary coolant system. With more than two hours available, the time curve in Figure 4.2 for NREP cognitive error is used to assess the probability that the operators fail to depressurize the primary coolant system. It is approximately 5×10^{-4} at two hours. It is

conservatively assumed that if the operators fail to depressurize in two hours, all ECCS are disabled due to flooding. This results in sequence 4 or 5 and sequence 9 or 10 in Figure 4.3. A probability of 5×10^{-2} is used in the event tree for operator failure to depressurize, because this event tree is conditional on the event that the operators have already failed to isolate the small LOCA, that is,

$$\begin{aligned}
&P(\text{failure to depressurize} \mid \text{failure to isolate})\\
&= P(\text{failure to depressurize and failure to isolate})\\
&\quad /P(\text{failure to isolate})\\
&= 5\times10^{-4}/10^{-2}\\
&= 5\times10^{-2}
\end{aligned}$$

It is also assumed that if the primary system is depressurized in two hours, no other ECCS system will be affected by the LOCA, except that RCIC and HPCI may be isolated due to high room temperature caused by steam that may go from the location of the LOCA to the RCIC or HPCI pump room through ventilation ducts. For screening purposes, it is assumed that if the operators fail to isolate the small LOCA in 30 minutes, RCIC and HPCI will be isolated by high pump room temperature. It can be seen from Figure 4.3 that the dominant core damage scenario for a small LOCA is due to failure of the operators to depressurize the primary system such that ECCSs are disabled due to flooding. The assessment of the unavailabilities of the systems in Figure 4.3 is described as follows.

- FW - The unavailability of feedwater system is based on the analysis of Ref. 5, where an event tree analysis for the availability of the feedwater system and the power conversion system given an inadvertent opening of relief valve is performed.

- HPCI & RCIC - Both systems are assumed unavailable due to steam induced isolation.

- ADS - The unavailability is based on the result of BNL review[5] of Shoreham PRA.

- LPCI & LPCS - Based on the result of BNL review[5] of Shoreham PRA, the unavailabilities of LPCI and LPCS are 2.7×10^{-3} and 3.6×10^{-3}, respectively. The unavailability of both systems is 6.2×10^{-4}. Since one loop of LPCI is assumed unavailable, the unavailability of both systems should be between 3.6×10^{-3} and 6.2×10^{-4}. 1.0×10^{-3} is used in the analysis.

- Condensate Pump - The unavailability is based on Ref. 5. It represents human error in controlling condensate injection.

As noted above, the event tree and failure probabilities in Figure 4.3 apply specifically to either of the two LPCI injection lines. As each similar line is analyzed, the interfacing LOCA induced system unavailabilities pertinent to that line are substituted for those shown on Figure 4.3. These interfacing line specific failure probabilities are listed in Table 4.1A. Sections 4.1 to 4.3 provide detailed line by line analyses for the three representative plants. The overall results for the three plants are summarized in Table 4.2.

4.1 Frequency of Core Damage for Peach Bottom

In this section, the interfacing lines identified in Section 2 for Peach Bottom are analyzed one by one. Frequency estimates are made based on operating event experience, current data searches, and where necessary, already published generic data. First, the test requirements for the PIVs are discussed and their effect on valve unavailability is considered. Then, a line by line analysis of each interfacing line is presented. Detailed descriptions are provided for the LPCI injection lines. For lines that are similar to LPCI, only the differences are discussed and the effects on the calculated results are provided. Table 4.3 summarizes the line by line results for the Peach Bottom plant.

4.1.1 Test Requirements for Pressure Isolation Valves

4.1.1.1 Operational Hydrostatic Test

This test is done before startup after refueling. The reactor pressure vessel is filled, and pressurized to 1000 psig. Leakage through the PIVs is

measured by opening test taps downstream of the valves. Table 4.4 lists the PIVs tested and the success criteria used.

4.1.1.2 Logic System Functional Test

This test is done every six months on ECCS systems. It can be done at shutdown or at power. The test procedures for the RHR and core spray systems require that a relay be energized to inhibit the "open" signal to the normally closed injection valve before an actuation signal is generated. The test engineer is required to initial this step in the procedure after it is performed. If this step is skipped, due to human error, the injection valve will be inadvertently opened. Given that the valve is inadvertently opened, the operator can manually reclose it or close the normally open injection valve. The test procedure also requires verification of injection valve position after the actuation signal is simulated. As far as the inadvertent opening of the injection valve is concerned, the test procedures for HPCI and RCIC are similar to those for the RHR and core spray, except that for HPCI the normally open injection valve is kept closed with a discharge valve override switch, and the normally closed injection valve is opened when the simulated actuation signal is generated. Since RCIC and HPCI have high head pumps, inadvertent opening during a logic system functional test is expected to cause injection to the vessel, not interfacing system LOCA. However, as part of the test, a high drywell pressure signal is generated after an isolation signal is inserted and has not been reset. This will cause the injection valves to open with the pump not running, if the signal to the outboard injection valve is not blocked. Therefore, inadvertent opening of the injection valve may lead to an overpressurization of the suction side of the pump.

4.1.1.3 Local Leak Rate Test (LLRT)

This is the type "C" test for containment isolation valves defined and discussed in Appendix J to 10CFR50. The valves in the interfacing lines that are subject to this test are the injection valves in the ECCS systems, the RHR shutdown cooling suction valves, the MOVs in vessel head spray line, and the feedwater check valves outside the drywell. The testable air operated check valves are not required to undergo type C tests. This test is required to be

performed once every operating cycle, in no case at intervals greater than two years. Typically, the test is done by pressurizing a test volume using service air, so that the valve or valves being tested define the test boundary. The test pressure across the valve is 49.2 psid and the leakage is established by measuring the flow needed to maintain the pressure. The success criteria is specified in terms of aggregate leakage through all containment isolation valves and all containment penetrations. The total leakage rate can not exceed 60% of the maximum allowable leakage rate at the calculated peak containment internal pressure related to the design basis accident. Although no success criteria is specified for individual valves, excessive leakage is expected to be detected during LLRT, because each individual leakage rate is recorded.

4.1.1.4 Valve Functional Test

The injection valves of the ECCS systems are stroke tested monthly. Each valve is stroked with the other injection valve closed. The stroke time is recorded. When testing the injection valves in the RHR or core spray system when the reactor pressure is greater than 100 psig, the bypass valve for the testable check valve is opened and the pipe section between the injection valves is pressurized by a N_2 bottle to reduce the pressure differential across the inboard injection valve. The opening and closing currents for the motor operators are also taken. The testable check valves are cycled only during a shutdown greater than 48 hours or after valve maintenance.

4.1.2 LPCI Injection Line

Quantitative analysis for the LPCI injection lines is described in detail in this section and summarized in Table 4.5. The valve arrangement in this line consists of a testable check valve, a normally closed MOV and a normally open MOV. The testable check valve is leak rate tested at 1000 psig during the operational hydrostatic test at every refueling, and is cycled every shutdown greater than 48 hours. Since the testable check valve is not leak tested after maintenance, the same failure that occurred at Brown's Ferry-1 and Hatch-2 may occur without detection, i.e., reversal of air flow and position indication. The frequency for such failure can be estimated based on two events in 1361 valve years, i.e., $2/1361 = 1.47\times10^{-3}$/year.

Given that the testable check valve is held open due to air reversal, the normally closed MOV is pressurized, the MOV may fail open due to valve rupture, failure to fully reclose following a subsequent cycling, or inadvertent opening. This MOV is cycled every month, local leak rate tested and hydrostatically tested every refueling. Given that the check valve is held open by the air operator after maintenance, the expected number of months before refueling is approximately six (one half an assumed yearly refueling cycle). The MOV is not designed to operate with the differential pressure across the valve close to the reactor pressure. To cycle the valve, first the normally open injection valve is closed, and the bypass valve around the testable check valve is opened, so that the inboard MOV is pressurized at the vessel side, then a nitrogen bottle is used to pressurize the pipe section between the two injection valves so that the pressure across the inboard MOV is less than 100 psi. If the outboard MOV fails to close fully, the operators will have problem pressurizing the pipe section. Therefore, the failure will be discovered. After cycling the inboard injection valve, the operator needs to drain the pipe section between the two injection valves, before the outboard injection valve is reopened, If the inboard injection valve fails to fully reclose, the operator will have a problem draining the pipe section. Therefore, the failure will be discovered. If the operator skips this draining step in the procedure, then the failure may go undetected. A human error probability of 3×10^{-3} is used for this operator error. Therefore, the probability that the MOV fails to fully reclose and the failure goes undetected is

$$1.07\times10^{-4}/\text{demand} * 6 \text{ demand} * 3\times10^{-3} = 1.93\times10^{-6},$$

where the probability of valve failure is taken from Table 4.1. Similarly, the probability that rupture occurs is

$$1.2\times10^{-3}/\text{ry} * 0.5 \text{ ry} = 6.0\times10^{-4},$$

where the failure rate for MOV rupture is derived in Appendix D.

Inadvertent opening of the MOV will occur if the operator misses a step in the six month logic system functional test. A human error probability of 3×10^{-3}

is used for such failure. It is taken from Table 20.7 of the Human Reliability Handbook.[6]

Another failure mode of the MOV is that the MOV is opened by a spurious signal generated by human errors during testing or maintenance, or hardware failures in its control logic. This is indicated as MOV "transfer open" in Table 4.5. The failure rate, 8.1×10^{-4}, is taken from Table 4.1.

Since that the scenario of the Browns Ferry-1 event is judged to be credible for Peach Bottom, the frequency of the scenario is estimated to be one event in 1361 years, i.e., 7.35×10^{-4} per reactor year.

The frequency of overpressurization in this LPCI line based on the experience at Browns Ferry-1 and Hatch-2 is

$$1.47 \times 10^{-3} \times (1.93 \times 10^{-6} + 6.0 \times 10^{-4} + 3.00 \times 10^{-3} + 4.05 \times 10^{-4}) + 7.35 \times 10^{-4}$$
$$= 7.41 \times 10^{-4}.$$

To determine the frequency of LOCA in such scenario, the specific cause of MOV failure needs to be considered. If the MOV failed to fully reclose after being cycled open, the flow through the valve is assumed to be limited by the gap between the disc and the seat. It will lift the relief valves, but will not necessarily cause a rupture to occur. Such a LOCA can be isolated by closing the normally open MOV. As was discussed earlier, 10^{-2} is used for the probability of failure to manually isolate. Therefore, the frequency of an unisolated small LOCA due to reversed air supply for the testable check valve and the failure of the MOV to fully close after being cycled is

$$1.47 \times 10^{-3} \times 1.93 \times 10^{-6} \times 0.01 = 2.83 \times 10^{-11}/\text{yr}.$$

In the case of MOV rupture or inadvertent opening, the MOV is widely open. Therefore, a rupture of low pressure piping is possible. The event tree in Figure 4.1 can be used to estimate the frequency of LOCA. If a pipe rupture occurs, the blowdown will cause the testable check valve to close. As was discussed earlier, 0.01 is used for the probability of failure for the check valve to close. If the check valve does close, it is assumed that a small LOCA

results due to open relief valves. Such a small LOCA can be manually isolated with failure probability 10^{-2}. If the check valve fails to close, it is assumed that a large LOCA results. The frequency of a large LOCA due to reversed air supply to the testable check valve and rupture of MOV is

$$1.47\times10^{-3} \times 6.0\times10^{-4} \times 10^{-3} \times 0.01 = 8.82\times10^{-12}/\text{yr}.$$

For illustration purposes, 10^{-3} is used here for the probability of pipe rupture. Similarly, the contribution due to inadvertent opening of the MOV is

$$1.47\times10^{-3} \times 3\times10^{-3} \times 10^{-3} \times 0.01 = 4.41\times10^{-11}/\text{yr},$$

the contribution due to transfer opening of the MOV is

$$1.47\times10^{-3} \times 4.05\times10^{-4} \times 10^{-3} \times 0.01 = 5.95\times10^{-12}/\text{yr},$$

and the contribution due to the Browns Ferry scenario is

$$7.35\times10^{-4} * 10^{-3} * 0.01 = 7.35\times10^{-9}/\text{ry}.$$

The frequency of a small LOCA due to reversed air supply to the testable check valve and rupture of MOV is

$$1.47\times10^{-3} \times 6.0\times10^{-4} \times [(1-10^{-3})\times10^{-2}+10^{-3}\times9.9\times10^{-3}] = 8.82\times10^{-9}/\text{yr}.$$

Similar contribution due to inadvertent opening is

$$1.47\times10^{-3} \times 3\times10^{-3} [(1-10^{-3})\times10^{-2}+10^{-3}\times9.9\times10^{-3}] = 4.41\times10^{-8}.$$

The contribution due to transfer opening is

$$1.47\times10^{-3} \times 4.05\times10^{-4} [(1-10^{-3}) \times 10^{-2} + 10^{-3} \times 9.9\times10^{-3}] = 5.95\times10^{-9}.$$

The contribution of the Browns Ferry scenario is

$$7.35\times10^{-4} * [(1-10^{-3}) * 10^{-2}+10^{-3} * 9.9\times10^{-3})] = 7.35\times10^{-6}/\text{ry}.$$

Table 4.5 summarizes the calculations described above based upon the incidents that occurred at Browns Ferry and Hatch-2. It also shows the calculations done based upon the other operating event experience.

The Cooper incident is similar to the Browns Ferry-1 incident, except that the testable check valve was held open by a broken sample probe. The effect of this failure mode is that if a blowdown occurs, the check valve will not be able to reclose. In case of a small LOCA, isolation can be carried out using the normally open MOV. The Pilgrim incident on September 29, 1983 is also similar to the Browns Ferry-1 incident in that the check valve was held open. The difference is that the testable check valve was partially open due to rusted linkage between the valve stem and the air operator. The check valve should be able to close when a blowdown occurs resulting from the pipe rupture. The failure probability is again assumed to be 10^{-2} for this failure mode.

The rest of the operating experience involving testable check valve failures did not result in overpressurization. These check valve failure incidents have been used to estimate the frequency of check valve failure. In the event at LaSalle-1 on September 14, 1983, the testable check valve was 35° open due to misalignment of interfacing gears and tight packing gland. Based on the description of the LER, the air operator inhibited motion in the closed direction. Therefore, this incident is analyzed in the same way the Browns Ferry-1 incident was analyzed, except that the check valve is not expected to close when a blowdown occurs. The remaining incidents in Table 4.5 involve leakage through the testable check valve. They are used to estimate the frequency of check valve leakage. If the MOV also fails open, the leakage is assumed limited by the check valve. Therefore, only a small LOCA is postulated to result.

The results of the above calculation are summarized in Table 4.5.

4.1.3 Core Spray Injection Lines

The Peach Bottom core spray injection lines have the same valve arrangement and the same test requirements as the LPCI lines. The only difference considered here is that core spray injection lines have their own injection

nozzles at the spray spargers in the vessel. The chance that any foreign material will go through the piping inside the vessel and reach the core spray testable check valves is negligible. Therefore, incidents like that which occurred at Cooper are not considered credible for these lines. This makes the frequencies listed in Table 4.3 for core spray lower than those for LPCI.

4.1.4 RCIC and HPCI

These lines differ from LPCI in the following ways:

a. An additional check valve in the feedwater line needs to fail open to result in a LOCA. If both the testable check valve and the normally closed MOV fail open, an overpressurization will occur. This may cause a transient that leads to feedwater pump trip. However, no LOCA will occur unless the check valve in the feedwater line also fails open. To account for this, a failure probability of 10^{-2} is used for the check valve when a low pressure pipe rupture occurs.

b. The testable check valves in the HPCI and RCIC lines were not hydrostatically tested in the first ten years of operation. This is assumed to directly increase the yearly frequency of testable check valve failure by a factor of ten.

c. The Pilgrim event on September 29, 1983, in which the air operated check valve was opened due to a rusted linkage between the valve stem and the attached air operator and the two discharge MOVs were simultaneously opened as a result of human errors in testing the HPCI injection valve logic and steam supply isolation valve logic, is judged to be credible for the HPCI and RCIC lines at Peach Bottom, because similar tests are also performed. This experience is used to estimate the frequency of this scenario of overpressurization.

The calculations for these lines are shown in Table 4.6.

4.1.5 Feedwater Line

The most notable operating experience associated with this line is the San Onofre-1 incident. The frequency for common cause failure of check valves in the feedwater line is estimated using the evidence of this one event in approximately 1000 reactor years as simply 10^{-3} per reactor year. For this particular event, this is also the frequency of overpressurization.

Based on the general arrangement plan in the Peach Bottom FSAR, feedwater heaters #3 and #4 (at level 135') are physically close to the battery rooms and the emergency switch gear rooms. These rooms may be affected by blowdown through a ruptured feedwater heater. The general arrangement plan shows that the heaters are inside their own compartments each with two doors. BNL was unable to enter these compartments during the site visit but was informed by Philadelphia Electric Company that the feedwater heater compartments are open at the ceiling. Therefore, overpressurization failure of any building structures is not expected to occur. Based on a tour of the turbine building, the 135' level is generally a big open area, with a large open floor area that connects this level to several lower levels. Therefore, flooding of this level can not exceed the height of the curb (approximately six inches). Equipment inside the switchgear rooms is at least one foot above the floor. Based upon drawing reviews and the site visits, it is assumed that ECCS systems are not affected by a rupture of a feedwater heater.

Figure 4.4 is an event tree for a postulated feedwater heater LOCA. The ASEP analysis for Peach Bottom[5] assessed the unavailability of ECCS during a large LOCA to be 1.24×10^{-4}. If an ECCS system is available, the operator still needs to isolate the break to stop the loss of coolant inventory to outside the containment, or provide makeup from sources outside the containment. There are MOVs in the feedwater line that can be used to isolate a feedwater heater rupture. The condensate storage tank and high pressure service water systems can be used to provide makeup. The primary system coolant inventory is approximately 165,000 gallons. The volume of the water in the suppression pool is approximately 875,000 gallons. When a large LOCA occurs, the ECC systems will reflood the vessel. After reflooding, there should be more than 700,000 gallons of water in the suppression pool. Assuming the break is not isolated

and that the operator keeps one LPCI pump running at its capacity of 10,000 gpm, it will take more than an hour before the suppression pool water is exhausted. This defines the time available for operator actions. The probability that the operators fail to carry out the needed action within the hour is assessed to be 10^{-3} using the NREP time curve in Figure 4.2.

4.1.6 RHR Suction From Recirculation

The two MOVs in this line are cycled every shutdown greater than 48 hours. They are also local leak rate tested and hydrostatically tested every refueling. No operating event experience of overpressurization has been observed for this line. Therefore, the failure rates in Table 4.1 have been used to analyze the frequency of overpressurization. Two modes of failure are considered, failure to fully reclose after being cycled (leak), and valve rupture. Given that there are two valves and two failure modes, four combinations of failures are possible.

a. Rupture-Rupture - It is assumed that the reactor is shutdown once every three months and any valve rupture will be discovered by cycling. It is also assumed that the outboard MOV is pressurized only after the inboard MOV has ruptured. The frequency of this failure combination for each three month period is

$$\frac{\lambda^2 T^2}{2} = \frac{2.06\text{x}10^{-6}\text{x}\ (\frac{3}{12})^2}{2} = 6.44\text{x}10^{-8}\ ,$$

where $2.06\text{x}10^{-6}$ is the mean of λ^2 derived in Appendix D.

For one year, the frequency is $2.58\text{x}10^{-7}$/ry. This is a failure mode that can not be isolated.

b. Leak-Leak - During each quarterly stroking of the MOVs, each valve has a probability of $6.4\text{x}10^{-3}$ to fail to fully close. If both valves fail to fully close, the failure is expected to be recognized during plant

heatup and corrected. Therefore, such failure mode is not further considered.

c. Leak-Rupture or Rupture-Leak - These combinations also lead to small LOCA. The frequency can be estimated by

P(failure to reclose) x 8 strokes/ry * $\lambda_{Rupture}$ * 6 months
= 5.14×10^{-7}/ry.

4.1.7 Vessel Head Spray

This line differs from the RHR shutdown cooling suction in that an additional check valve failure is needed to cause an overpressurization. This check valve performs the same function as the air operated check valves in the injection lines of ECSS. Therefore, the failure experience for air operated check valves also applies to the check valve, with the exception of those failures that involve air operators. Four events of air operated check valve failures in Table 3.2 are not related to the air operator. Therefore, the failure rate of the check valve is estimated to be four events in 1361 years, i.e., 2.94×10^{-3} per year. Since the check valve is not tested in any way. The average probability over 40 years that the check valve is in a failed state is

$$2.94\times10^{-3} \text{ per year} * 40 \text{ years}/2 = 5.88\times10^{-2}.$$

Therefore, this has simply been applied as a multiplicative factor to the results for the RHR suction line.

4.2 Frequency of Core Damage for Nine Mile Point-2

Similar to the analysis for Peach Bottom, operating experience and generic data have been used to assess the frequency of overpressurization. The test requirements for the PIVs at NMP-2 differ from those already discussed for Peach Bottom. This leads to significant difference in quantitative results for the ECCS injection lines. For example, NMP-2 performs type "C" leak rate test and PIV leak rate testing after maintenance of the testable check valves. Therefore, if the testable check valve is held open by the air operator due to

reversal of air supply during maintenance, the failure will be detected by the leak rate tests. Section 4.2.1 describes test requirements for the PIVs and the impact on the use of operating event experience in the quantitative analysis. Other sections provide line by line analysis. Table 4.7 summarizes the calculations for all of the interfacing line at Nine Mile Point-2.

4.2.1 Test Requirements for Pressure Isolation Valves

4.2.1.1 Pressure Isolation Valve Leak Rate Test

This test is done by pressurizing the pipe section downstream of the PIV being tested to between 1000 and 1040 psig, using a test pump. The test pump takes suction from a 50 gallon container. The decrease of water level in the container over five minutes is used to calculate the leakage rate. Table 4.8 lists the PIVs and the applicable test success criteria. These tests are performed once every operating cycle at refueling or cold shutdown and after maintenance.

4.2.1.2 Valve Operability Test

PIVs are required to be cycled at cold shutdown if not cycled in the past 92 days, except valves in the RHR steam condensing line that may be cycled when reactor is at power. PIVs F052 and F218 in the RHR steam condensing line are required to be cycled every 92 days. Valve cycling is done from the control room, by turning the switch for the valve being tested and watching the valve position indication. PIV F087 is cycled when the high/low pressure interface interlock is calibrated once a cycle.

4.2.1.3 Local Leak Rate Test

The test method has been described in Section 4.1.1.3. The test pressure at NMP-2 is 40 psig. All PIVs in the lines listed in Table 4.7, except valves in the RHR steam condensing line, are also containment isolation valves and, therefore, are subject to LLRT requirements. The LLRT test frequency is once every 24 months. The testable check valves also undergo LLRT after maintenance. Therefore, if the air supply to the check valve is reversed, it can be discovered in the post maintenance test.

4.2.1.4 Automatic Actuation Test

Per the Technical Specifications, NMP-2 is required to perform automatic actuation testing on the ECCS once every 18 months. This test is not performed when the reactor is at power. ECCS actuation instrumentation response time is tested during hot shutdown, cold shutdown or refueling. ECCS response time is tested during cold shutdown or refueling. Therefore, when the reactor is operating, the failure mode of inadvertent opening of injection valves caused by human error during such tests is not considered.

4.2.2 LPCI Injection Lines

The valve arrangement in these lines consists of a testable check valve and a normally closed MOV. They are local leak rate tested and PIV leak rate tested once every 18 months. They are also cycled at every cold shutdown if they have not been cycled in the past 92 days.

The approach used in the quantitative analysis for these interfacing lines is similar to that for LPCI of Peach Bottom. The following describes the difference between the two:

a. NMP-2 does not cycle the PIVs in the LPCI lines when the reactor is at power. It is assumed for this analysis that the injection valve is cycled once every three months at cold shutdown.

b. NMP-2 performs LLRT and PIV leak rate testing after testable check valve maintenance. Therefore, it has been assumed that a failure mode similar to the air reversal that happened at Browns Ferry-1 and Hatch-2 will be detected during the post maintenance leak tests. For the same reason, the failure mode of misalignment after maintenance like that happened at LaSalle-1 can also be detected.

c. No auto actuation test is performed at NMP-2 when the reactor is operating. Therefore, the failure mode of inadvertent opening during such testing is not considered.

d. NMP-2 has only one MOV in each LPCI line, therefore, if a small LOCA occurs due to MOV rupture, it has been assumed to be impossible for the operator to isolate it.

e. RCIC system at NMP-2 is isolated by high area temperature in the RHR rooms. Therefore, in the modelling, when a small LOCA is assumed to occur in one of the RHR rooms, RCIC is also assumed to be unavailable to mitigate the incident.

Figure 4.5 is the small LOCA event tree for the NMP-2 LPCI injection line for the rupture failure mode of the MOV. The unavailability of RCIC is 1.0 based upon the discussion above. The unavailability of the low pressure systems is estimated based on the number of loops available. For example, similar to Peach Bottom, 10^{-3} is used in sequence 16 of Figure 4.5, because two LPCI loops and the LPCS loop are available. When all three LPCI loops and the LPCS loop are available, 6.2×10^{-4} is used. This is taken from BNL review of the Shoreham PRA,[5] i.e., the unavailability of both LPCI AND LPCS. The unavailability of HPCS is taken from RSSMAP Grand Gulf.[8] The first three branches for the top event "X" in Figure 4.5 represent human error in depressurization given that a high head system is available. It is similar to the same event in Figure 4.3 for Peach Bottom, except that it is not conditional on operator error in isolating the break. Because the MOV is assumed to be ruptured, and no other valve is available for isolation. The failure probability for this event is based on the NREP[3] time curve at two hours.

Table 4.9 summarizes the calculation for LPCI lines.

4.2.3 LPCS Injection Line

This line is identical to the NMP-2 LPCI injection lines described above, except that the testable check valve failure due to foreign material is not considered credible on the same basis as described previously for the Peach Bottom core spray system.

4.2.4 Shutdown Cooling Return to Recirculation

These lines are treated identically to the LPCI injection lines described above.

4.2.5 HPCS Injection Line

This line is similar to the LPCS injection line, except that the HPCS pump discharge is high pressure. Therefore, the pump discharge check valve must also fail, in order to result in overpressurization of the low pressure portions of the system. Two failure modes of the pump discharge check valve are considered, leakage and rupture. It is assumed that check valve leakage can not be detected. Appendix D discusses the sources of the failure rates for the check valves. Therefore, the probability that the check valve is leaking when the PIVs in this line fail open is

$$2.94x10^{-3}/ry \times 40ry \div 2 = 5.88x10^{-2}.$$

Pump discharge check valve rupture can occur only after it is pressurized. It is has been assumed that if both PIVs in this line fail open, the time at which the failures occur will be in the middle of the year, i.e., the check valve is pressurized for six months. Therefore, the probability that rupture occurs in six months is

$$8.8x10^{-4}/ry \times 0.5 = 4.4x10^{-4}.$$

Table 4.10 summarizes the calculation for this line.

4.2.6 Vessel Head Spray Line

The vessel head spray line is connected with both RCIC and RHR loop B. Two testable check valves are used as containment isolation valves. They are local leak rate tested and PIV leak rate tested every 18 months. They are also cycled at every cold shutdown if not cycled in the past 92 days. Two failure modes are considered applicable to these valves, i.e., leak and stuck open due to rusted linkage similar to that which happened at Pilgrim on September 29, 1983. The

failure rates based on this experience are estimated to be $\lambda_1 = 2.94\text{x}10^{-3}$/ry and $\lambda_2 = 7.35\text{x}10^{-4}$/ry, respectively. Four combinations of failures of the two testable check valves are possible. Their frequencies per year are:

$$\frac{\lambda_1^2}{2}, \frac{\lambda_1\lambda_2}{2}, \frac{\lambda_2\lambda_1}{2}, \text{ and } \frac{\lambda_2^2}{2}.$$

They are listed in Table 4.11. The squares of the failure rates are calculated in Appendix D to be the mean of the squares of the failure rates. The first three combinations can only result in leakage, because at least one valve is only leaking. The last combination may lead to a large LOCA.

Outside the containment, the vessel head spray line is connected with RCIC and RHR loop B. In the RCIC line, there is a normally closed MOV which is local leak rate tested and cycled at each cold shutdown if not cycled in the past 92 days. In the RHR loop B, there is a check valve as well as a normally closed MOV. The MOV in the RHR loop B is subject to PIV leak test in addition to those tests required for the MOV in the RCIC line. Therefore, the dominant overpressurization path is the RCIC injection line due to the fewer valves required to fail to result in an overpressurization. Failure modes assumed for the MOV in the RCIC injection line are shown in Table 4.11. During RCIC system functional testing (which is required to be performed once every 18 months when the reactor is either operating or at hot standby) this MOV is opened. Therefore, a probability of 0.5 is used for the event that the system functional test is performed after the testable check valve failures occur and before the next local leak rate test is performed on the check valves.

4.2.7 Feedwater Line

The analysis for this line is the same as that for Peach Bottom feedwater lines. Based on the information provided by Nine Mile Point 2 and a plant visit, the only safety related equipment in the turbine building at NMP-2 is some instrument rack related to MSIV. The feedwater heaters at NMP-2 are open to the large volume of the general area inside the building. If a blowdown should occur at a feedwater heater, the flood will have to fill a large volume

in the pipe tunnel underneath the heater bay before it can overflow and threaten the service water system. Therefore, it has been assumed that the blowdown does not affect systems needed to mitigate the accident.

4.2.8 Shutdown Cooling Suction Line

The valve arrangement and test requirements for this line at NMP-2 are very similar to that at Peach Bottom. The same quantified results are used.

4.2.9 Steam Condensing Line to RHR Heat Exchanger

This line is connected to the RCIC steam supply line outside the containment and feeds directly to the RHR heat exchanger. The RCIC steam line has two normally open containment isolation valves. The steam condensing line is normally pressurized up to the first barrier that consists of two MOVs in parallel, F052 and its one-inch bypass valve F218. They are PIV leak tested once every 18 months and cycled once every 92 days. The second barrier also consists of two MOVs in parallel, F051 and F087. They are PIV leak tested once every 18 months. During calibration of interlocks on the PIVs, valve F087 is also cycled. The frequency of calibration is once every 18 months.

Failures of the following pairs of valves will lead to overpressurization: F052 and F051, F052 and F087, F218 and F051, and F218 and F087. Due to the similarity in the calculation of the frequency of overpressurization only one pair, F052 and F087, is discussed in detail. The difference between this pair of valves and other pairs is also provided. Table 4.12 summarizes calculations for all above pairs of valves.

F052 is cycled four times a year. If F087 fails open when F052 is opened, then an overpressurization will occur. The possible failure modes of F087 are rupture and transfer opening. Assuming F087 can rupture only if it is pressurized, and that F052 is opened for ten minutes, the probability of F087 rupture is

$$1.2\text{x}10^{-3}/\text{ry x } 10/1440\text{x}365 = 2.28\text{x}10^{-8}.$$

Given an overpressurization, the analysis is the same as that for other lines. In the case of a small LOCA, it is assumed that the probability of failure of isolation is 2.0×10^{-3} which is the probability used in Ref. 5 for common mode failure of both isolation valves.

Two other failure modes for F052, rupture, is analyzed in the same way. They are analyzed in the same way. An additional failure mode for F087 is that it is opened when the interlock is calibrated. A probability of 0.5 is used based on the probability that the test comes after the failure. This scenario turns out to be the dominant contributor to core damage frequency.

The pair F218 and F087 is identical to the pair F052 and F087, except that F218 is a one-inch valve. It is assumed that only a small LOCA may result if both F218 and F087 fail open. The pair F052 and F051 is identical to the pair F052 and F087, except that no interlock calibration is performed on valve F051. The pair F218 and F051 is identical to the pair F218 and F087, except that no interlock calibration is performed on F051.

4.3 Frequency of Core Damage for Quad Cities

The interfacing lines and their valve arrangements at Quad Cities are also very similar to those at Peach Bottom. The test requirements on the pressure isolation valves, however, are significantly different. Section 4.3.1 discusses the current test requirements on the PIVs. The following discussion provides the major differences between Quad Cities and Peach Bottom:

a. Quad Cities has one additional check valve in the feedwater line downstream of both HPCI and RCIC injection lines. This affects the analysis of RCIC and HPCI lines. When a pipe rupture occurs in these lines, this additional check valve should also close and terminate the blowdown. As opposed to the analysis for Peach Bottom, a probability of 10^{-3} has been used for the common mode failure of both valves to close. This reduces the frequencies for large LOCA and core damage in both the HPCI and RCIC lines by an order of magnitude.

b. The RCIC system at Quad Cities is located in the train B core spray pump room. This affects the calculation in that if a small LOCA occurs in the train B core spray room, the RCIC system will also be unavailable. Although the converse situation could also hold true, i.e., that the train B core spray could be rendered unavailable by a LOCA in the RCIC, it does not alter the quantitative results as a small LOCA is considered to be isolated by at least one of the three RCIC check valves and for a large LOCA, core damage is postulated directly.

c. Quad Cites is not required to perform PIV leak rate testing on any PIVs. The testable check valves are not local leak rate tested either. Therefore, if a testable check valve is opened due to reversal of the air supply and the position indication is also reversed as in the Browns Ferry and Hatch events, the failure will go undetected.

d. Quad Cities just recently installed a safe shutdown system which discharges to the discharge line of HPCI. It operates in the same way as RCIC except that it has a motor-driven pump instead of a turbine-driven pump. The effect of this additional high head pump on the conditional probability of core damage, given a small LOCA, is that the unavailability of the high head systems is decreased. The effect on the frequency of interfacing LOCA is small because the low pressure portion of the system is separated from the RPV by seven valves in series including check, motor operated gate, and motor operated globe valves.

e. The crosstie between the two LPCI loops at Quad Cities is normally open. Therefore, if the PIVs in one LPCI loop fail open, both loops will experience overpressurization. It is assumed that if a small LOCA results from the overpressurization, both loops of LPCI are unavailable.

f. Quad Cities does not perform auto actuation logic testing of ECCS systems when the reactor is at power. Therefore, the failure mode of inadvertently opening an MOV during logic testing while at power is not considered.

The quantitative analysis for Quad Cities is similar to that for Peach Bottom. Line by line analysis is provided in Sections 4.3.2 to 4.3.6. Table 4.13 summarizes the results for Quad Cities.

4.3.1 Test Requirements for Pressure Isolation Valves

4.3.1.1 Pressure Isolation Valve Leak Rate Test

No PIV leak rate test is required for Quad Cities.

4.3.1.2 Valve Operability Test

Injection valves in ECCS systems are stroked once every month. this is done by first closing the other injection valve in the line and then stroking the valve being tested. No pressure equalization across the valve is needed. Valve timing is performed every three months. Isolation valves in the shutdown cooling suction and vessel head spray lines are stroked at every cold shutdown. Testable check valves are only stroked at cold shutdown or refueling.

4.3.1.3 Local Leak Rate Test

Local leak rate testing is performed on the inboard injection valves in the LPCI lines, on the shutdown cooling suction valves, on the feedwater check valves, and on the MOVs in vessel head spray line. It is done every refueling and the test pressure is 48 psi.

4.3.1.4 ECCS Automatic Actuation Test

This test is required once every refueling, and is performed at cold shutdown.

4.3.1.5 Valve Position Indication Surveillance

This is performed at least once every two years, and the Quad Cities procedures state that it preferably be done during refueling. The MOVs and testable check valves are cycled while verifying that the control room indication accurately reflects valve position by observing the valve stem

movement and the local/remote position indicators. All PIVs are subject to this test except valves in RCIC system and the check valve in the vessel head spray line.

4.3.2 LPCI Injection Lines

The valve arrangement and test requirements in the the LPCI lines are the same as those for Peach Bottom, except that the testable check valves are not leak tested, and that the auto actuation test is only done at cold shutdown. Therefore, the failure of the testable check valves may go undetected. Since Quad Cities has operated for more than ten years, and any failure in the past may have gone undetected, it has been assumed that the probability that the check valve is in a failed state is increased by a factor of ten. Also, if the check valve fails open, the time at which failure occurs is most likely to be before the year that is being considered. Therefore, if the MOV fails open any time in the year, overpressurization is assumed to result. Since inadvertent opening of the injection valve during an auto actuation testing is not considered as discussed above, a generic failure rate for MOVs transfer open is used. The Vermont Yankee event, in which the air operated check valve was leaking and the normally open injection valve fail to fully close when it was closed before the normally closed MOV was cycled, is judged to be credible for the LPCI lines at Quad Cities, because similar stroke test without pressure equalization is performed. This experience is used to estimate the frequency of overpressurization due to such scenario. Such overpressurization is assumed to lead to small LOCA, because the isolation valves are only leaking. Figure 4.6 illustrates the small LOCA event tree for one of the LPCI lines at Quad Cities. The unavailability of the safe shutdown system is assumed to be the same as that for the HPCS of Grand Gulf.[8] Due to the open crosstie between the LPCI loops, only the core spray system is considered available. The unavailability of the core spray system has been taken from the BNL review[5] of the Shoreham PRA. Table 4.14 summarizes the calculations for this line.

4.3.3 Core Spray Injection Lines

These lines differ from the Quad Cities LPCI lines in that the Cooper-type incident (i.e., foreign material under valve disc) is considered credible, in

that the spargers are assumed to effectively prevent any sizable debris from working is way back to the check valves. Also, the low pressure system unavailability in the small LOCA event tree from Figure 4.6 is changed, the low pressure injection function failure probability has been lowered to account for the availability of one train of core spray and both trains of LPCI, whereas for the LPCI line failure event tree only the two core spray trains were available due to the LPCI crosstie. This lowered the failure probability of the low pressure injection function by a factor of 3.6 as is shown in Table 4.1A.

4.3.4 HPCI and RCIC

The HPCI and RCIC injection lines at Quad Cities differ from those at Peach Bottom in that an additional check valve exists in the feedwater line and that the ECCS automatic actuation test is not done when the reactor is at power. The effect of the second feedwater check valve is a factor of ten reduction in the large LOCA frequency based on the assumption that large flow conditions will force the check valve closed and terminate the LOCA. Table 4.15 summarizes the calculations for these lines.

4.3.5 Feedwater Line

Based on a meeting with plant personnel at Quad Cities the only safety related equipment in the turbine building are electrical cables and some electrical buses and they are located far away from the feedwater heaters and at different elevations. Therefore, it has been assumed that no ECCS systems are affected by a large LOCA in any feedwater line, and the same quantitative analysis as that for Peach Bottom can be used.

4.3.6 RHR Suction and Vessel Head Spray

The valve arrangements and test requirement for these lines are the same as those for Peach Bottom. The same quantitative results are therefore used.

4.4 References

1. H. S. Mahta and R. W. Howard, "BWR Owner's Group Assessment of Emergency Core Cooling System Pressurization in Boiling Water Reactors," Draft Report, June 30, 1986.

2. "Reactor Safety Study," WASH-1400, NUREG-75/014, U.S. Nuclear Regulatory Commission, 1975.

3. G. Apostolakis and T-L. Chu, "Time-Dependent Accident Sequences Including Human Actions," Nuclear Technology, Vol. 64, February 1984.

4. D. Ilberg and N. Hanan, "An Evaluation of Unisolated LOCA Outside the Drywell in the Shoreham Nuclear Power Station," Technical Report, A-3740, Brookhaven National Laboratory, June 18, 1985.

5. D. Ilberg, K. Shiu, N. Hanan, and E. Anavim, "A Review of the Shoreham Nuclear Power Station Probabilistic Risk Assessment," NUREG/CR-4050, May 1985.

6. A. D. Swain and H. E. Guttmann, "Handbook of Human Reliability Analysis With Emphasis on Nuclear Power Plant Applications," NUREG/CR-1278, August 1983.

7. "Reference Plant Accident Sequence Likelihood Characterization - Peach Bottom, Unit 2," Draft Report, Vol. 3, NUREG/CR-4550, April 24, 1986.

8. Steven W. Hatch, "Reactor Safety Study Methodology Application Program Grand Gulf #1 BWR Power Plant," NUREG/CR-1659/4-of-4, October 1981.

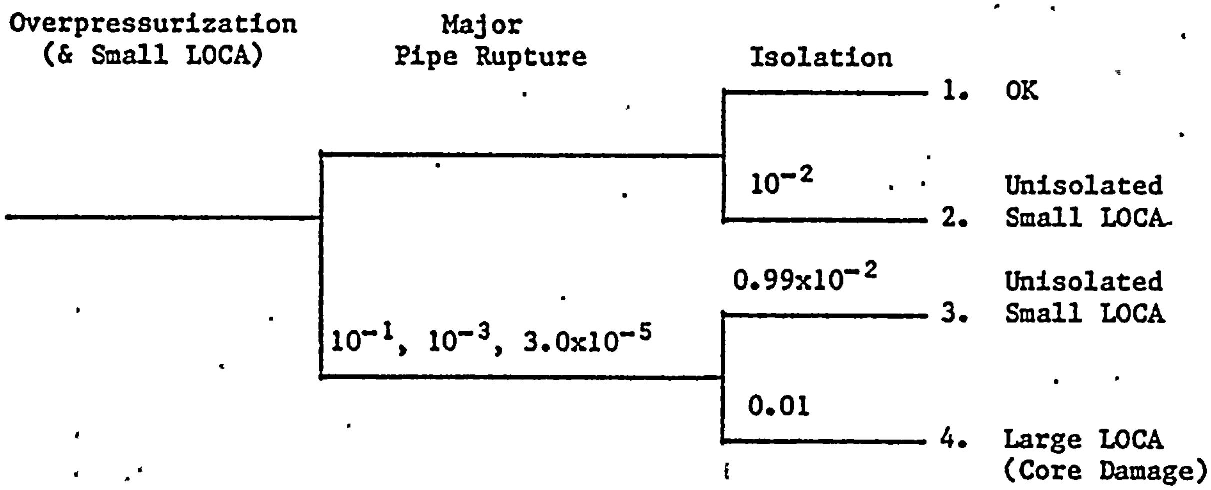

Figure 4.1. Event tree for conditional probability of LOCAs resulting from an overpressurization.

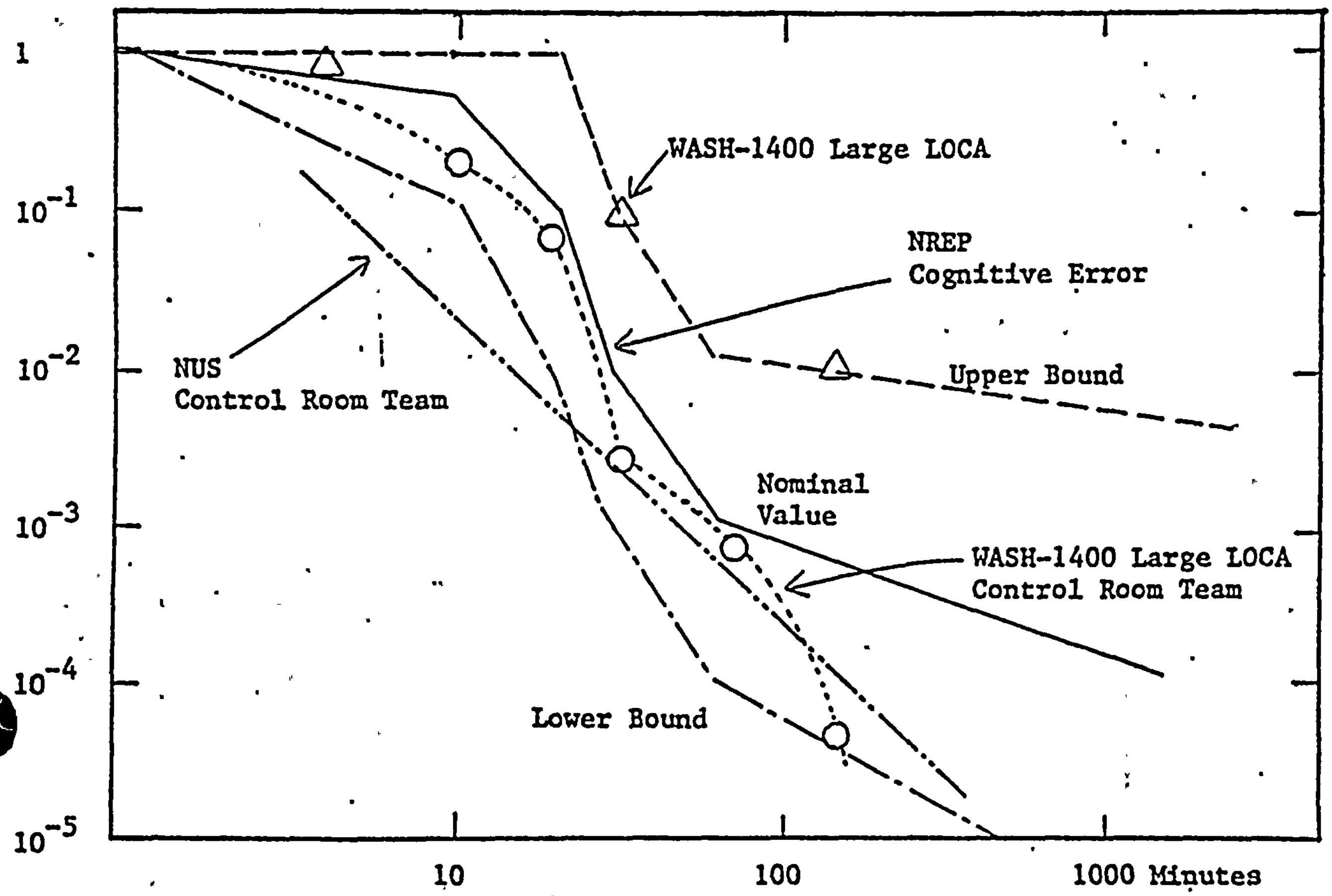

Figure 4.2. Time curves for operator actions.

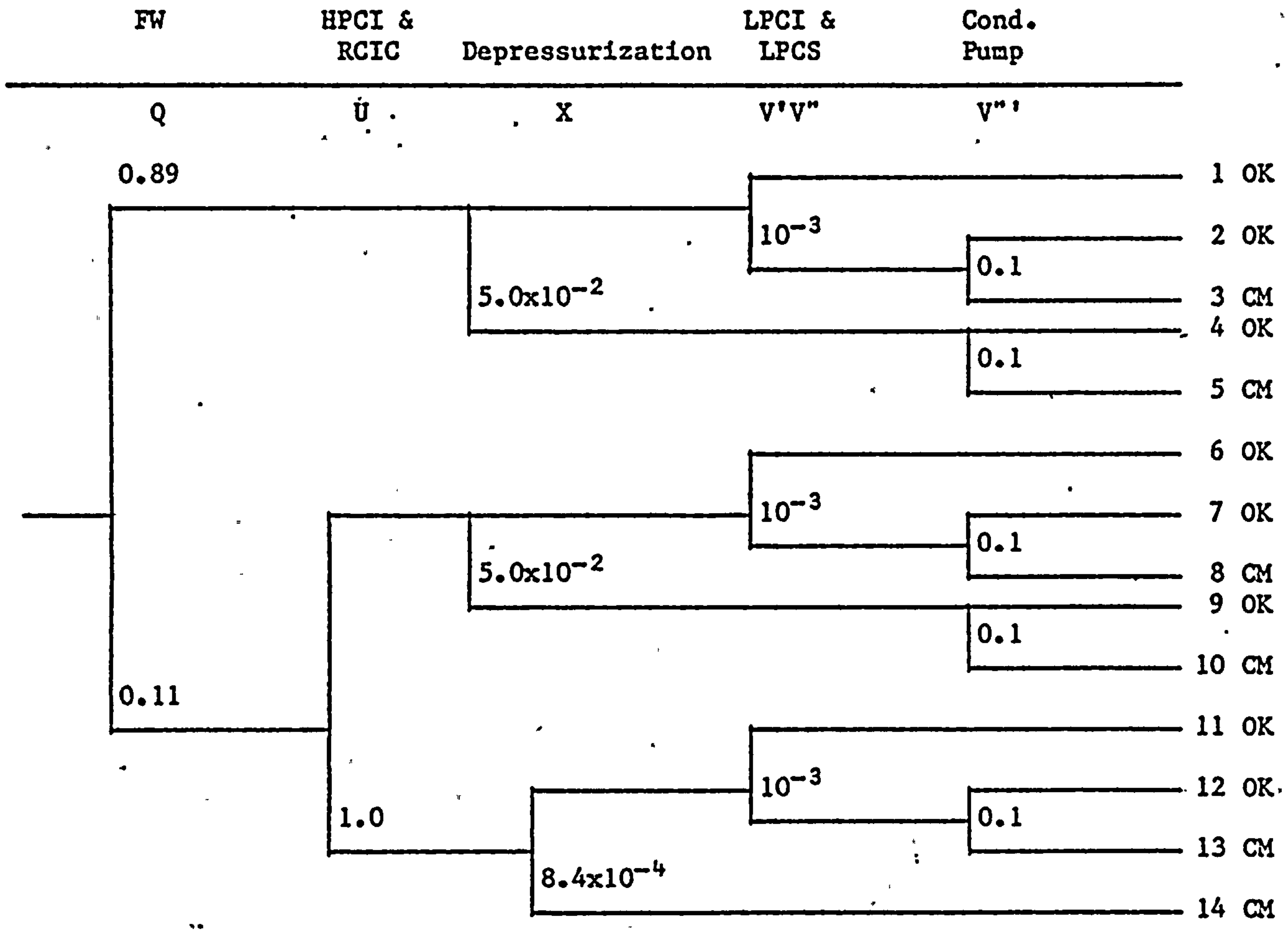

Figure 4.3. Event tree for a small LOCA outside the containment (LPCI line at Peach Bottom).

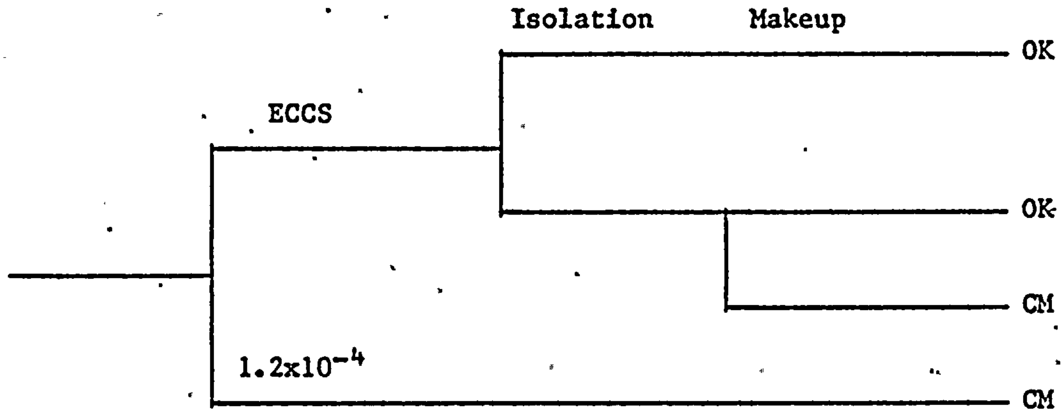

Figure 4.4. Event tree for feedwater heater rupture.

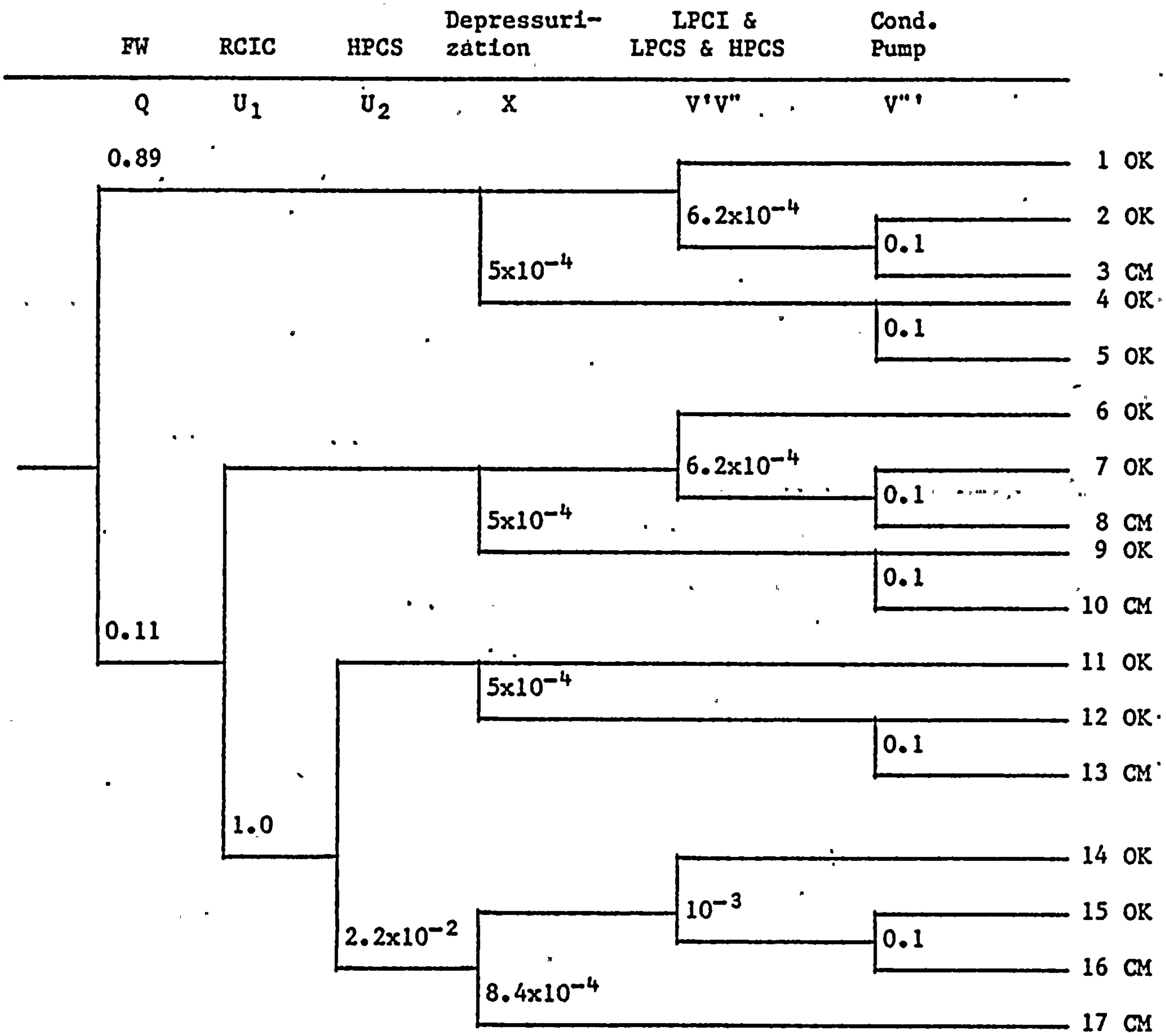

Figure 4.5. Event tree for a small LOCA outside the containment (LPCI Line at NMP-2).

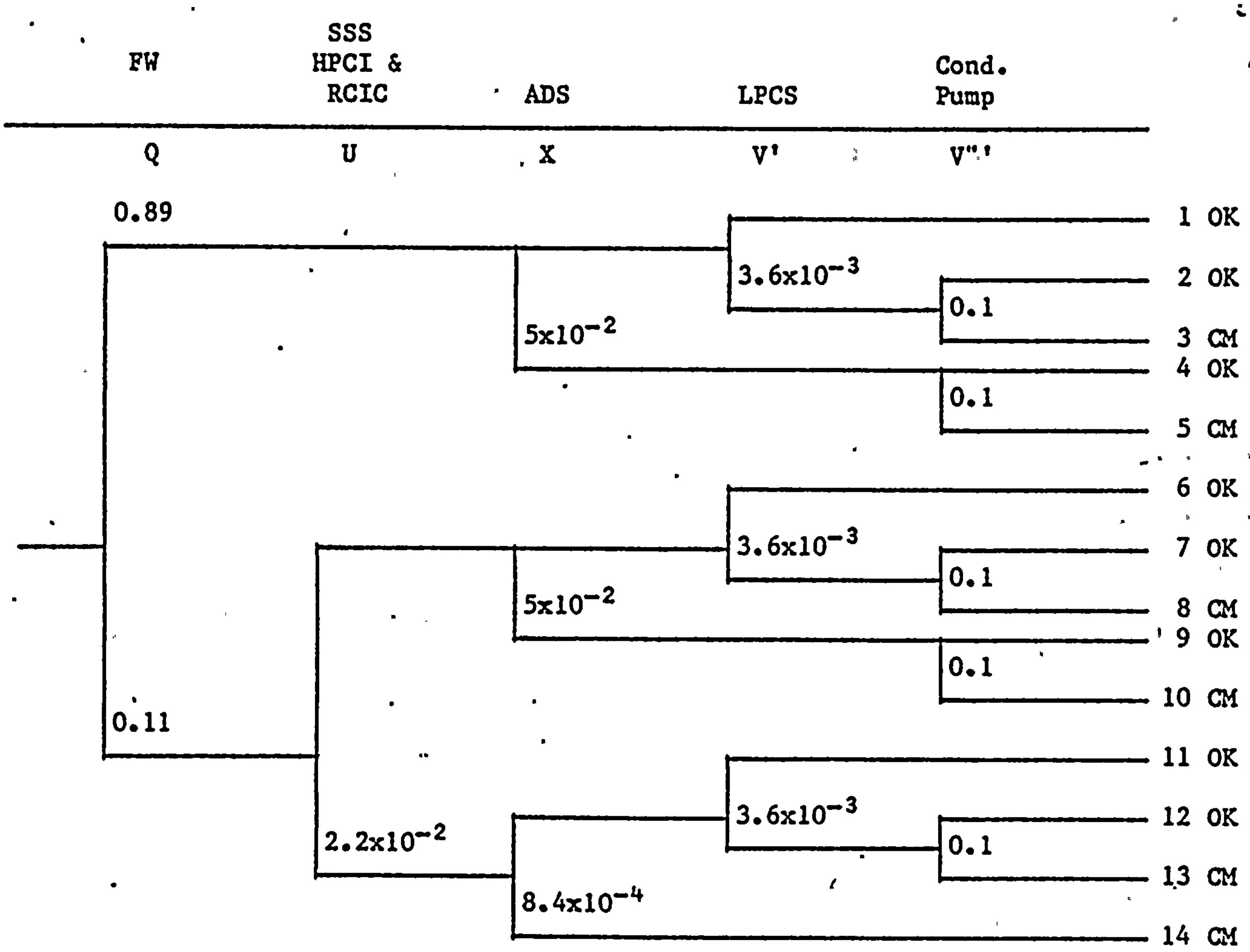

Figure 4.6. Event tree for a small LOCA outside the containment (LPCI line at Quad Cities).

Table 4.1
Some Data Used in the Quantification of the Frequency of Intersystem LOCAs

Failure Event	Failure Data	Sources
1. MOV Rupture	$1.20x10^{-3}$(/ry)	See Appendix D
2. MOV Transfer Open	$8.10x10^{-4}$(/ry)	Seabrook PRA
3. MOV Failure to Close While Indicating Closed	$1.07x10^{-4}$(/demand)	Seabrook PRA
4. MOV Inadvertently Opened	$3x10^{-3}$(/demand)	Handbook of Human Reliability Analysis
5. AOV Opened Due to Reversed Air Supply	$1.47x10^{-3}$(/ry)	See Appendix D
6. AOV Opened Due to Foreign Material	$7.35x10^{-4}$(/ry)	See Appendix D
7. AOV Opened Due to Rusted Linkage	$7.35x10^{-4}$(/ry)	See Appendix D
8. AOV Opened Due to Misalignment of Gears	$7.35x10^{-4}$(/ry)	See Appendix D
9. AOV Leak	$2.94x10^{-3}$(/ry)	See Appendix D
10. Check Valve Rupture	$8.80x10^{-4}$(/ry)	PSA Procedures Guide
11. Check Valve Leak	$2.94x10^{-3}$(/ry)	Same as AOV Leak
12. Lamda Rupture Square (MOV)	$2.06x10^{-6}$(/ry^2)	$EX^2=(EX)^2+var.$
13. Lamda Leak Square	$2.20x10^{-8}$(/ry^2)	$EX^2=(EX)^2+var.$
14. Lamda Leak Square (AOV)	$1.09x10^{-5}$(/ry^2)	$EX^2=(EX)^2+var.$
15. Lamda Rust Square	$2.13x10^{-6}$(/ry^2)	$EX^2=(EX)^2+var.$

Table 4.1A
Line Specific Failure Probabilities Used
in the Small LOCA Event Trees

	Q	U	X	V'V"	V"'	CDP
Peach Bottom						
LPCI	0.11	1.0	$5x10^{-2}/8.4x10^{-4}$	10^{-3}	0.1	$4.64x10^{-3}$
LPCS	0.11	1.0	$5x10^{-2}/8.4x10^{-4}$	10^{-3}	0.1	$4.64x10^{-3}$
RHR Suction	0.11	1.0	$5x10^{-2}/8.4x10^{-4}$	10^{-3}	0.1	$4.64x10^{-3}$
Head Spray	0.11	1.0	$5x10^{-2}/8.4x10^{-4}$	10^{-3}	0.1	$4.64x10^{-3}$
Quad Cities						
LPCI	0.11	$2.2x10^{-2}$	$5x10^{-2}/8.4x10^{-4}$	$3.6x10^{-3}$	0.1	$5.36x10^{-3}$
LPCS	0.11	$2.2x10^{-2}$	$5x10^{-2}/8.4x10^{-4}$	10^{-3}	0.1	$5.36x10^{-3}$
RHR Suction	0.11	$2.2x10^{-2}$	$5x10^{-2}/8.4x10^{-4}$	$3.6x10^{-3}$	0.1	$5.36x10^{-3}$
Head Spray	0.11	$2.2x10^{-2}$	$5x10^{-2}/8.4x10^{-4}$	$3.6x10^{-3}$	0.1	$5.36x10^{-3}$

	Q	U_1	U_2	X	V'V"	V"'	CDP
Nine Mile Point-2							
LPCI	0.11	1.0	$2.2x10^{-2}$	$5x10^{-4}/8.4x10^{-4}$	$6.2x10^{-4}/10^{-3}$	0.1	$1.08x10^{-4}$
LPCS	0.11	1.0	$2.2x10^{-2}$	$5x10^{-4}/8.4x10^{-4}$	$6.2x10^{-4}/10^{-3}$	0.1	$1.08x10^{-4}$
SDC Return	0.11	1.0	$2.2x10^{-2}$	$5x10^{-4}/8.4x10^{-4}$	$6.2x10^{-4}/10^{-3}$	0.1	$1.08x10^{-4}$
HPCS	0.11	1.0	1.0	$5x10^{-4}/8.4x10^{-4}$	$6.2x10^{-4}$	0.1	$1.99x10^{-4}$
Head Spray	0.11	1.0	$2.2x10^{-2}$	$5x10^{-4}/8.4x10^{-4}$	$6.2x10^{-4}/10^{-3}$	0.1	$1.08x10^{-4}$
RHR Suction	0.11	1.0	$2.2x10^{-2}$	$5x10^{-4}/8.4x10^{-4}$	$6.2x10^{-4}/10^{-3}$	0.1	$1.08x10^{-4}$
Steam Condensing	0.11	1.0	$2.2x10^{-2}$	$5x10^{-4}/8.4x10^{-4}$	$6.2x10^{-4}/10^{-3}$	0.1	$1.08x10^{-4}$

Table 4.2
Summary of Results

Plant	f(OP)	P(Rupture)	S2	A	CDF
Peach Bottom	9.01×10^{-3}	1.00E-01	3.11E-05	1.05E-04	5.49×10^{-6}
		1.00E-03	3.12E-05	1.05E-06	1.98×10^{-7}
		3.00E-05	3.12E-05	3.16E-08	1.46×10^{-7}
Nine Mile Point-2	9.93E-03	1.00E-01	3.37E-05	3.23E-04	2.23E-04
		1.00E-03	3.44E-05	3.23E-06	2.23E-06
		3.00E-05	3.44E-05	9.68E-08	7.13E-08
Quad Cities	6.89×10^{-3}	1.00E-01	4.15E-05	1.09E-04	9.59×10^{-6}
		1.00E-03	4.16E-05	1.09E-06	3.17×10^{-7}
		3.00E-05	4.16E-05	3.28E-08	2.26E-07

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
CDF = Core Damage Frequency (/ry).

Table 4.3
Summary of Results for Peach Bottom

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.52E-03	1.00E-01	1.52E-05	2.66E-06	2.73E-06
		1.00E-03	1.52E-05	2.66E-08	9.73E-08
		3.00E-05	1.52E-05	7.99E-10	7.14E-08
CS	1.52E-03	1.00E-01	1.51E-05	2.08E-06	2.15E-06
		1.00E-03	1.52E-05	2.08E-08	9.11E-08
		3.00E-05	1.52E-05	6.23E-10	7.10E-08
HPCI	2.97E-02	1.00E-01	0.00E+00	2.32×10^{-7}	2.32×10^{-7}
		1.00E-03	0.00E+00	2.32×10^{-9}	2.32×10^{-9}
		3.00E-05	0.00E+00	6.95×10^{-11}	6.95×10^{-11}
RCIC	2.97E-02	1.00E-01	0.00E+00	2.32E-07	2.32×10^{-7}
		1.00E-03	0.00E+00	2.32E-09	2.32×10^{-9}
		3.00E-05	0.00E+00	6.95E-11	6.95×10^{-11}
Feedwater	1.00E-03	1.00E-01	0.00E+00	1.00E-04	1.12E-07
		1.00E-03	0.00E+00	1.00E-06	1.12E-09
		3.00E-05	0.00E+00	3.00E-08	3.36E-11
RHR Suction	7.71E-07	1.00E-01	7.45E-07	2.58E-08	2.92E-08
		1.00E-03	7.71E-07	2.58E-10	3.83E-09
		3.00E-05	7.71E-07	7.73E-12	3.59E-09
Vessel Head Spray	4.53E-08	1.00E-01	4.38E-08	1.51E-09	1.72E-09
		1.00E-03	4.53E-08	1.51E-11	2.25E-10
		3.00E-05	4.53E-08	4.54E-13	2.11E-10

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
CDF = Core Damage Frequency (/ry).

Table 4.4
List of PIVs Tested in Operational Hydrostatic
Test at Peach Bottom

Valve		Acceptable Rate
AO-14-13A	Testable Check Valve, Core Spray A	360 cc/hr
AO-14-13B	Testable Check Valve, Core Spray B	360 cc/hr
AO-10-46A	Testable Check Valve, RHRA	720 cc/hr
AO-10-46B	Testable Check Valve, RHRB	720 cc/hr
MO-10-25A	Inboard Injection Valve, RHRA	720 cc/hr
MO-10-25B	Inboard Injection Valve, RHRB	720 cc/hr
MO-14-12A	Inboard Injection Valve, Core Spray A	360 cc/hr
MO-14-12B	Inboard Injection Valve, Core Spray B	360 cc/hr
MO-10-18	Inboard Suction Valve, RHR Shutdown Cooling	600 cc/hr
MO-10-17	Outboard Suction Valve, RHR Shutdown Cooling	600 cc/hr
MO-23-19	Inboard Injection Valve, HPCI	420 cc/hr
MO-13-21	Inboard Injection Valve, RCIC	180 cc/hr

Table 4.5
Summary of Calculations for LPCI of Peach Bottom

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Browns Ferry-1	1.47E-03	1.93E-06	2.83E-09	0.00E+00	2.83E-11	0.00E+00
Hatch-2		Failure to		0.00E+00	2.83E-11	0.00E+00
(Reverse Air)		Reclose		0.00E+00	2.83E-11	0.00E+00
		6.00E-04	8.82E-07	1.00E-01	8.81E-09	8.82E-10
		Rupture		1.00E-03	8.82E-09	8.82E-12
				3.00E-05	8.82E-09	2.65E-13
		3.00E-03	4.41E-06	1.00E-01	4.40E-08	4.41E-09
		Inadvertent Opening		1.00E-03	4.41E-08	4.41E-11
				3.00E-05	4.41E-08	1.32E-12
		4.05E-04	5.95E-07	1.00E-01	5.95E-09	5.95E-10
		Transfer Open		1.00E-03	5.95E-09	5.95E-12
				3.00E-05	5.95E-09	1.79E-13
Browns Ferry Scenario			7.35E-04	1.00E-01	7.34E-06	7.35E-07
(Reverse Air, Inadvertent Opened)				1.00E-03	7.35E-06	7.35E-09
				3.00E-05	7.35E-06	2.20E-10
Cooper	7.35E-04	1.93E-06	1.42E-09	0.00E+00	1.42E-11	0.00E+00
(Foreign Material)		Failure to		0.00E+00	1.42E-11	0.00E+00
		Reclose		0.00E+00	1.42E-11	0.00E+00
		6.00E-04	4.41E-07	1.00E-01	3.97E-09	4.41E-08
		Rupture		1.00E-03	4.40E-09	4.41E-10
				3.00E-05	4.41E-09	1.32E-11
		3.00E-03	2.20E-06	1.00E-01	1.98E-08	2.20E-07
		Inadvertent Opening		1.00E-03	2.20E-08	2.20E-09
				3.00E-05	2.20E-08	6.61E-11
		4.05E-04	2.98E-07	1.00E-01	2.68E-09	2.98E-08
		Transfer Open		1.00E-03	2.97E-09	2.98E-10
				3.00E-05	2.98E-09	8.93E-12
Pilgrim-1	7.35E-04	1.93E-06	1.42E-09	0.00E+00	1.42E-11	0.00E+00
Sept. 29, 1983		Failure to Reclose		0.00E+00	1.42E-11	0.00E+00
(Rusted Linkage)				0.00E+00	1.42E-11	0.00E+00
		6.00E-04	4.41E-07	1.00E-01	4.40E-09	4.41E-10
		Rupture		1.00E-03	4.41E-09	4.41E-12
				3.00E-05	4.41E-09	1.32E-13
		3.00E-03	2.20E-06	1.00E-01	2.20E-08	2.20E-09
		Inadvertent Opening		1.00E-03	2.20E-08	2.20E-11
				3.00E-05	2.20E-08	6.61E-13
		4.05E-04	2.98E-07	1.00E-01	2.97E-09	2.98E-10
		Transfer Open		1.00E-03	2.98E-09	2.98E-12
				3.00E-05	2.98E-09	8.93E-14

Table 4.5 (Continued)

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
LaSalle-1	7.35E-04	1.93E-06	1.42E-09	0.00E+00	1.42E-11	0.00E+00
Sept. 14, 1983		Failure to Reclose		0.00E+00	1.42E-11	0.00E+00
(Misalignment of Gears)				0.00E+00	1.42E-11	0.00E+00
		6.00E-04	4.41E-07	1.00E-01	3.97E-09	4.41E-08
		Rupture		1.00E-03	4.40E-09	4.41E-10
				3.00E-05	4.41E-09	1.32E-11
		3.00E-03	2.20E-06	1.00E-01	1.98E-08	2.20E-07
		Inadvertent Opening		1.00E-03	2.20E-08	2.20E-09
				3.00E-05	2.20E-08	6.61E-11
		4.05E-04	2.98E-07	1.00E-01	2.68E-09	2.98E-08
		Transfer Open		1.00E-03	2.97E-09	2.98E-10
				3.00E-05	2.98E-09	8.93E-12
Four Remaining	2.94E-03	1.93E-06	5.66E-09	0.00E+00	5.66E-11	0.00E+00
Incidents		Failure to Reclose		0.00E+00	5.66E-11	0.00E+00
(Leakage)				0.00E+00	5.66E-11	0.00E+00
		6.00E-04	1.76E-06	0.00E+00	1.76E-08	0.00E+00
		Rupture		0.00E+00	1.76E-08	0.00E+00
				0.00E+00	1.76E-08	0.00E+00
		3.00E-03	8.82E-06	0.00E+00	8.82E-08	0.00E+00
		Inadvertent Opening		0.00E+00	8.82E-08	0.00E+00
				0.00E+00	8.82E-08	0.00E+00
		4.05E-04	1.19E-06	0.00E+00	1.19E-08	0.00E+00
		Transfer Open		0.00E+00	1.19E-08	0.00E+00
				0.00E+00	1.19E-08	0.00E+00

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
AOV = Failure Rate of Air Operated Check Valve (/ry).
MOV = Probability of MOV Failure.

Table 4.6
Summary of Calculations for RCIC and HPCI of Peach Bottom

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A ..
Browns Ferry-1	1.47E-02	1.20E-03	1.76E-05	1.00E-01	0.00E+00	1.76E-09
Hatch-2		Rupture		1.00E-03	0.00E+00	1.76E-11
(Reversed Air)				3.00E-05	0.00E+00	5.29E-13
		3.00E-03	4.41E-05	1.00E-01	0.00E+00	4.41E-09
		Inadvertent Opening		1.00E-03	0.00E+00	4.41E-11
				3.00E-05	0.00E+00	1.32E-12
		8.10E-04	1.19E-05	1.00E-01	0.00E+00	1.19E-09
		Transfer Open		1.00E-03	0.00E+00	1.19E-11
				3.00E-05	0.00E+00	3.57E-13
Browns Ferry Scenario			7.35×10^{-4}	1.00E-01	0.00E+00	7.35×10^{-8}
(Reverse Air, Inadvertent Opened)				1.00E-03	0.00E+00	7.35×10^{-10}
				3.00E-05	0.00E+00	2.20×10^{-11}
Cooper	7.35E-03	1.20E-03	8.82E-06	1.00E-01	0.00E+00	8.82E-09
(Foreign Material)				1.00E-03	0.00E+00	8.82E-11
				3.00E-05	0.00E+00	2.65E-12
		3.00E-03	2.20E-05	1.00E-01	0.00E+00	2.20E-08
				1.00E-03	0.00E+00	2.20E-10
				3.00E-05	0.00E+00	6.61E-12
		8.10E-04	5.95E-06	1.00E-01	0.00E+00	5.95E-09
				1.00E-03	0.00E+00	5.95E-11
				3.00E-05	0.00E+00	1.79E-12
Pilgrim-1	7.35E-03	1.20E-03	8.82E-06	1.00E-01	0.00E+00	8.82E-10
Sept. 29, 1983		Rupture		1.00E-03	0.00E+00	8.82E-12
(Rusted Linkage)				3.00E-05	0.00E+00	2.65E-13
		3.00E-03	2.20E-05	1.00E-01	0.00E+00	2.20E-09
		Inadvertent Opening		1.00E-03	0.00E+00	2.20E-11
				3.00E-05	0.00E+00	6.61E-13
		8.10E-04	5.95E-06	1.00E-01	0.00E+00	5.95E-10
		Transfer Open		1.00E-03	0.00E+00	5.95E-12
				3.00E-05	0.00E+00	1.79E-13
Pilgrim Scenario			7.35E-04	1.00E-01	0.00E+00	7.35E-08
(Rusted Linkage, HE in Testing)				1.00E-03	0.00E+00	7.35E-10
				3.00E-05	0.00E+00	2.20E-11
LaSalle-1	7.35E-03	1.20E-03	8.82E-06	1.00E-01	0.00E+00	8.82E-09
Sept. 14, 1983		Rupture		1.00E-03	0.00E+00	8.82E-11
(Misalignment of Gears)				3.00E-05	0.00E+00	2.65E-12
		3.00E-03	2.20E-05	1.00E-01	0.00E+00	2.20E-08
		Inadvertent Opening		1.00E-03	0.00E+00	2.20E-10
				3.00E-05	0.00E+00	6.61E-12
		8.10E-04	5.95E-06	1.00E-01	0.00E+00	5.95E-09
		Transfer Open		1.00E-03	0.00E+00	5.95E-11
				3.00E-05	0.00E+00	1.79E-12

Notes of Table 4.5.

Table 4.7
Summary of Results for Nine Mile Point-2

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.33E-05	1.00E-01	7.85E-06	2.24E-07	2.25E-07
		1.00E-03	7.99E-06	2.24E-09	3.37×10^{-9}
		3.00E-05	7.99E-06	6.71E-11	1.2×10^{-9}
LPCS	3.69E-06	1.00E-01	2.22E-06	7.38E-10	1.05×10^{-9}
		1.00E-03	2.22E-06	7.38E-12	3.21×10^{-10}
		3.00E-05	2.22E-06	2.22E-13	3.14×10^{-10}
SDC Return	8.86E-06	1.00E-01	5.24E-06	1.49E-07	1.50E-07
		1.00E-03	5.33E-06	1.49E-09	2.07E-09
		3.00E-05	5.33E-06	4.47E-11	6.20E-10
HPCS	2.65E-07	1.00E-01	2.65E-07	3.25E-13	5.31E-11
		1.00E-03	2.65E-07	3.25E-15	5.28E-11
		3.00E-05	2.65E-07	9.75E-17	5.28E-11
Vessel Head Spray	4.35E-06	1.00E-01	5.05E-08	5.34E-11	2.74×10^{-10}
		1.00E-03	5.05E-08	5.34E-13	2.21×10^{-10}
		3.00E-05	5.05E-08	1.60E-14	2.20×10^{-10}
Feedwater	1.00E-03	1.00E-01	0.00E+00	1.00E-04	1.12E-07
		1.00E-03	0.00E+00	1.00E-06	1.12E-09
		3.00E-05	0.00E+00	3.00E-08	3.36E-11
RHR Suction	7.71E-07	1.00E-01	7.45E-07	2.58E-08	2.58E-08
		1.00E-03	7.71E-07	2.58E-10	3.41E-10
		3.00E-05	7.71E-07	7.73E-12	9.10E-11
Steam Condensing	8.90E-03	1.00E-01	1.73×10^{-5}	2.22E-04	2.22E-04
		1.00E-03	1.78×10^{-5}	2.22E-06	2.23E-06
		3.00E-05	1.78×10^{-5}	6.67E-08	6.86E-08

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
CDF = Core Damage Frequency (/ry).

Table 4.8
PIVs Tested in PIV Leak Rate Test at Nine Mile Point

Valve	Description	Success Criteria Gal/Min
F041(16)*	Testable Check Valve, LPCI	5.0
F042(24)	Injection Valve, LPCI	5.0
F009(112)	Shutdown Cooling Suction Valve	5.0
F008(113)	Shutdown Cooling Suction Valve	5.0
F050(39)	Testable Check Valve, Shutdown Cooling Return	5.0
F053(40)	Injection Valve, Shutdown Cooling Return	5.0
F052(22)	Steam Supply to RHR HX	4.0
F218(80)	RHR Steam Line Bypass	0.5
F051(21)	RHR HX Press. Cont.	4.0
F087(23)	Steam Supply to RHR HX	4.0
F006(101)	Testable Check Valve, LPCS	5.0
F005(104)	Injection Valve, LPCS	5.0
F005(108)	Testable Check Valve, HPCS	5.0
F004(107)	Injection Valve, HPCS	5.0
F066(157)	Testable Check Valve, RCIC	1.0
F065(156)	Testable Check Valve, RCIC	1.0

*Number in parenthesis is the valve number used by Stone & Webster.

Table 4.9
Summary Calculations for LPCI of Nine Mile Point-2

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Cooper (Foreign Material)	7.35E-04	6.00E-04 Rupture	4.41E-07	1.00E-01	3.97E-07	4.41E-08
				1.00E-03	4.40E-07	4.41E-10
				3.00E-05	4.41E-07	1.32E-11
		4.05E-04 Transfer Open	2.98E-07	1.00E-01	2.68E-09	2.98E-08
				1.00E-03	2.97E-09	2.98E-10
				3.00E-05	2.98E-09	8.93E-12
Pilgrim-1 Sept. 29, 1983	7.35E-04	6.00E-04 Rupture	4.41E-07	1.00E-01	4.40E-07	4.41E-10
				1.00E-03	4.41E-07	4.41E-12
				3.00E-05	4.41E-07	1.32E-13
		4.05E-04 Transfer Open	2.98E-07	1.00E-01	2.97E-09	2.98E-10
				1.00E-03	2.98E-09	2.98E-12
				3.00E-05	2.98E-09	8.93E-14
Four Remaining Incidents (Leak)	2.94E-03	6.00E-04 Rupture	1.76E-06	0.00E+00	1.76E-06	0.00E+00
				0.00E+00	1.76E-06	0.00E+00
				0.00E+00	1.76E-06	0.00E+00
		4.05E-04 Transfer Open	1.19E-06	0.00E+00	1.19E-08	0.00E+00
				0.00E+00	1.19E-08	0.00E+00
				0.00E+00	1.19E-08	0.00E+00

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
AOV = Failure Rate of Air Operated Check Valve (/ry).
MOV = Probability of MOV Failure.

Table 4.10
Summary Calculations for HPCS of Nine Mile Point-2

Experience	AOV	MOV	Check	f(OP)	P(Rupture)	S2	A
Pilgrim-1	7.35E-04	2.14E-04	5.88E-02	9.25E-09	0.00E+00	9.25E-09	0.00E+00
Sept. 29, 1983		Failure	Leak		0.00E+00	9.25E-09	0.00E+00
(Rusted Linkage)		to Reclose			0.00E+00	9.25E-09	0.00E+00
			4.40E-04	6.92E-11	0.00E+00	6.92E-11	0.00E+00
			Rupture		0.00E+00	6.92E-11	0.00E+00
					0.00E+00	6.92E-11	0.00E+00
		6.00E-04	5.88E-02	2.59E-08	0.00E+00	2.59E-08	0.00E+00
		Rupture	Leak		0.00E+00	2.59E-08	0.00E+00
					0.00E+00	2.59E-08	0.00E+00
			4.40E-04	1.94E-10	1.00E-01	1.94E-10	1.94E-13
			Rupture		1.00E-03	1.94E-10	1.94E-15
					3.00E-05	1.94E-10	5.82E-17
		4.05E-04	5.88E-02	1.75E-08	0.00E+00	1.75E-08	0.00E+00
		Transfer	Leak		0.00E+00	1.75E-08	0.00E+00
		Open			0.00E+00	1.75E-08	0.00E+00
			4.40E-04	1.31E-10	1.00E-01	1.31E-10	1.31E-13
			Rupture		1.00E-03	1.31E-10	1.31E-15
					3.00E-05	1.31E-10	3.93E-17
Four Remaining	2.94E-03	2.14E-04	5.88E-02	3.70E-08	0.00E+00	3.70E-08	0.00E+00
Incidents		Failure	Leak		0.00E+00	3.70E-08	0.00E+00
		to Reclose			0.00E+00	3.70E-08	0.00E+00
			4.40E-04	2.77E-10	0.00E+00	2.77E-10	0.00E+00
			Rupture		0.00E+00	2.77E-10	0.00E+00
					0.00E+00	2.77E-10	0.00E+00
		6.00E-04	5.88E-02	1.04E-07	0.00E+00	1.04E-07	0.00E+00
		Rupture	Leak		0.00E+00	1.04E-07	0.00E+00
					0.00E+00	1.04E-07	0.00E+00
			4.40E-04	7.76E-10	0.00E+00	7.76E-10	0.00E+00
			Rupture		0.00E+00	7.76E-10	0.00E+00
					0.00E+00	7.76E-10	0.00E+00
		4.05E-04	5.88E-02	7.00E-08	0.00E+00	7.00E-08	0.00E+00
		Transfer	Leak		0.00E+00	7.00E-08	0.00E+00
		Open			0.00E+00	7.00E-08	0.00E+00
			4.40E-04	5.24E-10	0.00E+00	5.24E-10	0.00E+00
			Rupture		0.00E+00	5.24E-10	0.00E+00
					0.00E+00	5.24E-10	0.00E+00

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
AOV = Failure Rate of Air-Operated Check Valve (/ry).
MOV = Probability of MOV Failure.

Table 4.11
Summary of Calculations for Vessel Head Spray of Nine Mile Point-2

Experience AOV1 AOV2	AOVs	MOV	f(OP)	P(Rupture)	S2	A
Leak+Leak	5.45E-06	2.14E-04	1.63E-09	0.00E+00	1.63E-09	0.00E+00
Leak+Rusted Linkage	1.08E-06	Failure to		0.00E+00	1.63E-09	0.00E+00
Rusted Linkage+Leak	1.08E-06	Reclose		0.00E+00	1.63E-09	0.00E+00
		6.00E-04	4.57E-09	0.00E+00	4.57E-09	0.00E+00
		Rupture		0.00E+00	4.57E-09	0.00E+00
Total Leak	7.61E-06			0.00E+00	4.57E-09	0.00E+00
		5.00E-01	3.80E-06	0.00E+00	3.80E-08	0.00E+00
		Opened in Test		0.00E+00	3.80E-08	0.00E+00
				0.00E+00	3.80E-08	0.00E+00
		4.05E-04	3.08E-09	0.00E+00	3.08E-11	0.00E+00
		Transfer Open		0.00E+00	3.08E-11	0.00E+00
				0.00E+00	3.08E-11	0.00E+00
Rusted Linkage(both)	1.06E-06	2.14E-04	2.28E-10	0.00E+00	2.28E-10	0.00E+00
		Failure to		0.00E+00	2.28E-10	0.00E+00
		Reclose		0.00E+00	2.28E-10	0.00E+00
		6.00E-04	6.39E-10	1.00E-01	6.39E-10	6.39E-14
		Rupture		1.00E-03	6.39E-10	6.39E-16
				3.00E-05	6.39E-10	1.92E-17
		5.00E-01	5.32E-07	1.00E-01	5.32E-09	5.33E-11
		Opened in Test		1.00E-03	5.32E-09	5.33E-13
				3.00E-05	5.32E-09	1.60E-14
		4.05E-04	4.31E-10	1.00E-01	4.31E-12	4.31E-14
		Transfer Open		1.00E-03	4.31E-12	4.31E-16
				3.00E-05	4.31E-12	1.29E-17

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
AOV = Failure Rate of Air Operated Check Valve (/ry).
MOV = Probability of MOV Failure.

Table 4.12
Summary Calculations for Steam Condensing Lines of Nine Mile Point-2

Pair	MOV1	MOV2	f(OP)	P(Rupture)	S2	A
F052&F087	4.00E+00	2.28E-08	9.13E-08	1.00E-01	1.74×10^{-10}	4.57E-09
	Cycling	Rupture		1.00E-03	1.83×10^{-10}	4.57E-11
	per ry			3.00E-05	1.83×10^{-10}	1.37E-12
		2.02E-04	8.10E-04	1.00E-01	1.54×10^{-6}	4.05E-05
		Transfer		1.00E-03	1.62×10^{-6}	4.05E-07
		Open		3.00E-05	1.62×10^{-6}	1.21E-08
	1.20E-03	6.00E-04	1.03E-06	1.00E-01	1.96×10^{-9}	5.15E-08
	Rupture	Rupture		1.00E-03	2.06×10^{-9}	5.15E-10
				3.00E-05	2.06×10^{-9}	1.55E-11
		5.00E-01	6.00E-04	1.00E-01	1.14×10^{-6}	3.00E-05
		Interlock		1.00E-03	1.20×10^{-6}	3.00E-07
		Calibration		3.00E-05	1.20×10^{-6}	9.00E-09
		8.10E-04	9.72E-07	1.00E-01	1.85×10^{-9}	4.86E-08
		Transfer		1.00E-03	1.94×10^{-9}	4.86E-10
		Open		3.00E-05	1.94×10^{-9}	1.46E-11
F218&F087	4.00E+00	2.28E-08	9.13E-08	1.00E-01	1.83×10^{-10}	0.00E+00
	Cycling	Rupture		1.00E-03	1.83×10^{-10}	0.00E+00
	per ry			3.00E-05	1.83×10^{-10}	0.00E+00
		2.02E-04	8.10E-04	1.00E-01	1.62×10^{-6}	0.00E+00
		Transfer		1.00E-03	1.62×10^{-6}	0.00E+00
		Open		3.00E-05	1.62×10^{-6}	0.00E+00
	1.20E-03	6.00E-04	1.03E-06	1.00E-01	2.06×10^{-9}	0.00E+00
	Rupture	Rupture		1.00E-03	2.06×10^{-9}	0.00E+00
				3.00E-05	2.06×10^{-9}	0.00E+00
		5.00E-01	6.00E-04	1.00E-01	1.2×10^{-6}	0.00E+00
		Interlock		1.00E-03	1.2×10^{-6}	0.00E+00
		Calibration		3.00E-05	1.2×10^{-6}	0.00E+00
		8.10E-04	9.72E-07	1.00E-01	1.94×10^{-9}	0.00E+00
		Transfer		1.00E-03	1.94×10^{-9}	0.00E+00
		Open		3.00E-05	1.94×10^{-9}	0.00E+00
F052&F051	4.00E+00	2.28E-08	9.13E-08	1.00E-01	1.74×10^{-10}	4.57E-09
	Cycling	Rupture		1.00E-03	1.83×10^{-10}	4.57E-11
	per ry			3.00E-05	1.83×10^{-10}	1.37E-12
		2.02E-04	8.10E-04	1.00E-01	1.54×10^{-6}	4.05E-05
		Transfer		1.00E-03	1.62×10^{-6}	4.05E-07
		Open		3.00E-05	1.62×10^{-6}	1.21E-08
	1.20E-03	6.00E-04	1.03E-06	1.00E-01	1.96×10^{-9}	5.15E-08
	Rupture	Rupture		1.00E-03	2.06×10^{-9}	5.15E-10
				3.00E-05	2.06×10^{-9}	1.55E-11
		8.10E-04	9.72E-07	1.00E-01	1.85×10^{-9}	4.86E-08
		Transfer		1.00E-03	1.94×10^{-9}	4.86E-10
		Open		3.00E-05	1.94×10^{-9}	1.46E-11

Table 4.12 (Continued)

Pair	MOV1	MOV2	f(OP)	P(Rupture)	S2	A
F218&F051	4.00E+00 Cycling per ry	2.28E-08 Rupture	9.13E-08	1.00E-01	1.83×10^{-10}	0.00E+00
				1.00E-03	1.83×10^{-10}	0.00E+00
				3.00E-05	1.83×10^{-10}	0.00E+00
		2.02E-04 Transfer Open	8.10E-04	1.00E-01	1.62×10^{-6}	0.00E+00
				1.00E-03	1.62×10^{-6}	0.00E+00
				3.00E-05	1.62×10^{-6}	0.00E+00
	1.20E-03 Rupture	6.00E-04 Rupture	1.03E-06	1.00E-01	2.06×10^{-9}	0.00E+00
				1.00E-03	2.06×10^{-9}	0.00E+00
				3.00E-05	2.06×10^{-9}	0.00E+00
		8.10E-04 Transfer Open	9.72E-07	1.00E-01	1.94×10^{-9}	0.00E+00
				1.00E-03	1.94×10^{-9}	0.00E+00
				3.00E-05	1.94×10^{-9}	0.00E+00

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
MOV = Probability of MOV Failure.

Table 4.13
Summary of Results for Quad Cities

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	2.07E-03	1.00E-01	2.07E-05	6.00E-06	6.11E-06
		1.00E-03	2.07E-05	6.00E-08	1.71E-07
		3.00E-05	2.07E-05	1.80E-09	1.13E-07
CS	2.01E-03	1.00E-01	2.00E-05	3.04E-06	3.15E-06
		1.00E-03	2.01E-05	3.04E-08	1.38E-07
		3.00E-05	2.01E-05	9.13E-10	1.09E-07
HPCI	7.52E-03	1.00E-01	0.00E+00	9.42×10^{-8}	9.42×10^{-8}
		1.00E-03	0.00E+00	9.42×10^{-10}	9.42×10^{-10}
		3.00E-05	0.00E+00	2.82×10^{-11}	2.82×10^{-11}
RCIC	7.52E-03	1.00E-01	0.00E+00	9.42×10^{-8}	9.42×10^{-8}
		1.00E-03	0.00E+00	9.42×10^{-10}	9.42×10^{-10}
		3.00E-05	0.00E+00	2.82×10^{-11}	2.82×10^{-11}
Feedwater	1.00E-03	1.00E-01	0.00E+00	1.00E-04	1.12E-07
		1.00E-03	0.00E+00	1.00E-06	1.12E-09
		3.00E-05	0.00E+00	3.00E-08	3.36E-11
RHR Suction	7.71E-07	1.00E-01	7.45E-07	2.58E-08	2.97E-08
		1.00E-03	7.71E-07	2.58E-10	4.39E-09
		3.00E-05	7.71E-07	7.73E-12	4.14E-09
Vessel Head Spray	4.53E-08	1.00E-01	4.38E-08	1.51E-09	1.75E-09
		1.00E-03	4.53E-08	1.51E-11	2.58E-10
		3.00E-05	4.53E-08	4.54E-13	2.43E-10

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
CDF = Core Damage Frequency (/ry).

Table 4.14
Summary Calculations for LPCI of Quad Cities

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Browns Ferry-1	1.47E-02	2.57E-03	3.77E-05	0.00E+00	3.77E-07	0.00E+00
Hatch-2		Failure to		0.00E+00	3.77E-07	0.00E+00
(Reverse Air)		Reclose		0.00E+00	3.77E-07	0.00E+00
		1.20E-03	1.76E-05	1.00E-01	1.76E-07	1.76E-08
		Rupture		1.00E-03	1.76E-07	1.76E-10
				3.00E-05	1.76E-07	5.29E-12
		8.10E-04	1.19E-05	1.00E-01	1.19E-07	1.19E-08
		Transfer Open		1.00E-03	1.19E-07	1.19E-10
				3.00E-05	1.19E-07	3.57E-12
Cooper	7.35E-03	2.57E-03	1.89E-05	0.00E+00	1.89E-07	0.00E+00
(Foreign Material)		Failure to		0.00E+00	1.89E-07	0.00E+00
		Reclose		0.00E+00	1.89E-07	0.00E+00
		1.20E-03	8.82E-06	1.00E-01	7.94E-08	8.82E-07
		Rupture		1.00E-03	8.81E-08	8.82E-09
				3.00E-05	8.82E-08	2.65E-10
		8.10E-04	5.95E-06	1.00E-01	5.36E-08	5.95E-07
		Transfer Open		1.00E-03	5.95E-08	5.95E-09
				3.00E-05	5.95E-08	1.79E-10
Pilgrim-1	7.35E-03	2.57E-03	1.89E-05	0.00E+00	1.89E-07	0.00E+00
Sept. 29, 1983		Failure to		0.00E+00	1.89E-07	0.00E+00
(Rusted Linkage)		Reclose		0.00E+00	1.89E-07	0.00E+00
		1.20E-03	8.82E-06	1.00E-01	8.81E-08	8.82E-09
		Rupture		1.00E-03	8.82E-08	8.82E-11
				3.00E-05	8.82E-08	2.65E-12
		8.10E-04	5.95E-06	1.00E-01	5.95E-08	5.95E-09
		Transfer Open		1.00E-03	5.95E-08	5.95E-11
				3.00E-05	5.95E-08	1.79E-12
LaSalle-1	7.35E-03	2.57E-03	1.89E-05	0.00E+00	1.89E-07	0.00E+00
Sept. 14, 1983		Failure to		0.00E+00	1.89E-07	0.00E+00
(Misalignment of Gears)		Reclose		0.00E+00	1.89E-07	0.00E+00
		1.20E-03	8.82E-06	1.00E-01	7.94E-08	8.82E-07
		Rupture		1.00E-03	8.81E-08	8.82E-09
				3.00E-05	8.82E-08	2.65E-10
		8.10E-04	5.95E-06	1.00E-01	5.36E-08	5.95E-07
		Transfer Open		1.00E-03	5.95E-08	5.95E-09
				3.00E-05	5.95E-08	1.79E-10

Table 4.14 (Continued)

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Four Remaining Incidents (Leak)	2.94E-02	2.57E-03	7.55E-05	0.00E+00	7.55E-07	0.00E+00
		Failure to		0.00E+00	7.55E-07	0.00E+00
		Reclose		0.00E+00	7.55E-07	0.00E+00
		1.20E-03	3.53E-05	0.00E+00	3.53E-07	0.00E+00
		Rupture		0.00E+00	3.53E-07	0.00E+00
				0.00E+00	3.53E-07	0.00E+00
		8.10E-04	2.38E-05	0.00E+00	2.38E-07	0.00E+00
		Transfer Open		0.00E+00	2.38E-07	0.00E+00
				0.00E+00	2.38E-07	0.00E+00
Vermont Yankee Scenario (Leak, Fail to Fully Close)			7.35E-04	0.00E+00	7.35E-06	0.00E+00
				0.00E+00	7.35E-06	0.00E+00
				0.00E+00	7.35E-06	0.00E+00

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
AOV = Failure Rate of Air Operated Check Valve (/ry).
MOV = Probability of MOV Failure.

Table 4.15
Summary of Calculations for RCIC and HPCI of Quad Cities

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Browns Ferry-1	1.47E-02	1.20E-03	1.76E-05	1.00E-01	0.00E+00	1.76E-09
Hatch-2		Rupture		1.00E-03	0.00E+00	1.76E-11
(Reverse Air)				3.00E-05	0.00E+00	5.29E-13
		8.10E-04	1.19E-05	1.00E-01	0.00E+00	1.19E-09
		Transfer Open		1.00E-03	0.00E+00	1.19E-11
				3.00E-05	0.00E+00	3.57E-13
Cooper	7.35E-03	1.20E-03	8.82E-06	1.00E-01	0.00E+00	8.82E-10
(Foreign Material)		Rupture		1.00E-03	0.00E+00	8.82E-12
				3.00E-05	0.00E+00	2.65E-13
		8.10E-04	5.95E-06	1.00E-01	0.00E+00	5.95E-10
		Transfer Open		1.00E-03	0.00E+00	5.95E-12
				3.00E-05	0.00E+00	1.79E-13
Pilgrim-1	7.35E-03	1.20E-03	8.82E-06	1.00E-01	0.00E+00	8.82E-10
Sept. 29, 1983		Rupture		1.00E-03	0.00E+00	8.82E-12
(Rusted Linkage)				3.00E-05	0.00E+00	2.65E-13
		8.10E-04	5.95E-06	1.00E-01	0.00E+00	5.95E-10
		Transfer Open		1.00E-03	0.00E+00	5.95E-12
				3.00E-05	0.00E+00	1.79E-13
Pilgrim Scenario			7.35E-04	1.00E-01	0.00E+00	7.35E-08
(Rusted Linkage, Failure to Fully Close)				1.00E-03	0.00E+00	7.35E-10
				3.00E-05	0.00E+00	2.20E-11
LaSalle-1	7.35E-03	1.20E-03	8.82E-06	1.00E-01	0.00E+00	8.82E-09
Sept. 14, 1983		Rupture		1.00E-03	0.00E+00	8.82E-11
(Misalignment of Gears)				3.00E-05	0.00E+00	2.65E-12
		8.10E-04	5.95E-06	1.00E-01	0.00E+00	5.95E-09
		Transfer Open		1.00E-03	0.00E+00	5.95E-11
				3.00E-05	0.00E+00	1.79E-12

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
AOV = Failure Rate of Air Operated Check Valve (/ry).
MOV = Probability of MOV Failure.

5. CORRECTIVE ACTIONS AND THEIR EFFECT ON CORE DAMAGE FREQUENCY

In this section, corrective actions for each of the three plants are discussed. The effect of the corrective actions on the frequency of overpressurization, the frequencies of LOCAs, and the frequency of core damage is provided.

5.1 Corrective Actions for Peach Bottom

Three corrective actions are considered for Peach Bottom. They are described in this section. Table 5.1 summarizes the base case results listed in Tables 4.2 and 4.3. Tables 5.2 to 5.4 summarize the quantitative results if the corrective actions are separately implemented. Table 5.5 shows the results if all three corrective actions are implemented. They can be compared with the results for the base case listed in Table 5.1.

5.1.1 Leak Test of Air Operated Check Valves After Maintenance

Some experienced failures of air operated check valves were caused by human errors during maintenance of the valves, e.g., events at Browns Ferry 1, Hatch 2, and LaSalle 1. These human errors can be detected and corrected, if a leak test is performed after maintenance. The test could be a LLRT or a PIV leak test. Table 5.2 shows the line by line results if this corrective action is implemented.

5.1.2 Perform Logic System Functional Test of ECCS Systems at Shutdown

The Browns Ferry incident occurred when a human error was committed in a logic system functional test. If such a test is not performed when the reactor is at power, the Browns Ferry type of incident no longer applies to Peach Bottom. Table 5.3 shows the line by line results if the MOV failure mode of inadvertent opening is removed from the base case calculations.

5.1.3 Leak Test of Air Operated Check Valves in the HPCI and RCIC Injection Lines at Every Refueling

These valves are currently not leak tested. In the base case analysis in Section 4, it was assumed that the check valve failure will not be detected, and this increased the frequency of check valve failure by a factor of ten and the exposure time of the MOV by a factor of two. Table 5.4 shows the results if these factors are removed.

5.2 Corrective Actions for Nine Mile Point 2

Two corrective actions are considered for Nine Mile Point 2. They are described in this section. Table 5.6 summarizes the base case results for Nine Mile Point listed in Tables 4.2 and 4.7. Tables 5.7 and 5.8 summarize the results given that the corrective actions are separately implemented. Table 5.9 shows the results if both corrective actions are implemented. Tables 5.7 to 5.9 can be compared with Table 5.6 to determine the benefits of the corrective actions.

5.2.1 Do Not Cycle Valves F052 and F218 at Power

Based on the analysis of Section 4, the dominant contributor to the core damage frequency due to an interfacing LOCA at Nine Mile Point 2 is that valves F052A(B) and F218A(B) are cycled open and the other MOVs in the lines fail open. Cycling of these valves at power makes these valves ineffective pressure barriers. If these valves are cycled only when the reactor is shutdown, the dominant core damage scenario is removed. Table 5.7 summarizes the line by line results if they are not cycled at power.

5.2.2 Do Not Cycle F087 at Power

Valves F087A and F087B are cycled at power when the interlocks for them are calibrated. For the same reason as was discussed in Section 5.2.1, cycling these valves at power increases the frequency of overpressurization and the frequency of core damage. Table 5.8 shows the line by line results if these valves are not cycled at power.

5.3 Corrective Actions for Quad Cities

Two corrective actions are considered for Quad Cities. They are described in this section. Table 5.10 summarizes the base case results listed in Table 4.2 and 4.13. Tables 5.11 and 5.12 summarize the quantitative results if the corrective actions are separately implemented. Table 5.13 summarizes the results if both corrective actions are implemented.

5.3.1 Leak Test Air Operated Check Valves

The air operated check valves at Quad Cities are currently not leak tested in any way. As was analyzed in Section 4, this caused a factor of ten increase in the probability of check valve failure and a factor of two increase in the exposure time of the MOV. Table 5.11 shows the line by line results for the corrective action of leak testing the air operated check valves every refueling.

5.3.2 Leak Test Air Operated Check Valves After Maintenance

This corrective action is identical to that for Peach Bottom discussed in Section 5.1.1. Table 5.12 shows the results for this corrective action.

Table 5.1
Summary of Results for Peach Bottom - Base Case

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.52E-03	1.00E-01	1.52E-05	2.66E-06	2.73E-06
		1.00E-03	1.52E-05	2.66E-08	9.73E-08
		3.00E-05	1.52E-05	7.99E-10	7.14E-08
CS	1.52E-03	1.00E-01	1.51E-05	2.08E-06	2.15E-06
		1.00E-03	1.52E-05	2.08E-08	9.11E-08
		3.00E-05	1.52E-05	6.23E-10	7.10E-08
HPCI	2.48E-03	1.00E-01	0.00E+00	2.32E-07	2.32E-07
		1.00E-03	0.00E+00	2.32E-09	2.32E-09
		3.00E-05	0.00E+00	6.95E-11	6.95E-11
RCIC	2.48E-03	1.00E-01	0.00E+00	2.32E-07	2.32E-07
		1.00E-03	0.00E+00	2.32E-09	2.32E-09
		3.00E-05	0.00E+00	6.95E-11	6.95E-11
Feedwater	1.00E-03	1.00E-01	0.00E+00	1.00E-04	1.12E-07
		1.00E-03	0.00E+00	1.00E-06	1.12E-09
		3.00E-05	0.00E+00	3.00E-08	3.36E-11
RHR Suction	7.71E-07	1.00E-01	7.45E-07	2.58E-08	2.92E-08
		1.00E-03	7.71E-07	2.58E-10	3.83E-09
		3.00E-05	7.71E-07	7.73E-12	3.59E-09
Vessel Head Spray	4.53E-08	1.00E-01	4.38E-08	1.51E-09	1.72E-09
		1.00E-03	4.53E-08	1.51E-11	2.25E-10
		3.00E-05	4.53E-08	4.54E-13	2.11E-10
Total	9.01E-03	1.00E-01	3.11E-05	1.05E-04	5.49E-06
		1.00E-03	3.12E-05	1.05E-06	1.98E-07
		3.00E-05	3.12E-05	3.16E-08	1.46E-07

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
CDF = Core Damage Frequency (/ry).

Table 5.2
Summary of Results for Peach Bottom - Leak Test AO Check After Maintenance

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	3.53E-05	1.00E-01	3.47E-07	5.94E-07	5.96E-07
		1.00E-03	3.53E-07	5.94E-09	7.58E-09
		3.00E-05	3.53E-07	1.78E-10	1.82E-09
CS	2.94E-05	1.00E-01	2.94E-07	5.89E-09	7.25E-09
		1.00E-03	2.94E-07	5.89E-11	1.42E-09
		3.00E-05	2.94E-07	1.77E-12	1.37E-09
HPCI	1.64E-03	1.00E-01	0.00E+00	1.14E-07	1.14E-07
		1.00E-03	0.00E+00	1.14E-09	1.14E-09
		3.00E-05	0.00E+00	3.42E-11	3.42E-11
RCIC	1.64E-03	1.00E-01	0.00E+00	1.14E-07	1.14E-07
		1.00E-03	0.00E+00	1.14E-09	1.14E-09
		3.00E-05	0.00E+00	3.42E-11	3.42E-11
Feedwater	1.00E-03	1.00E-01	0.00E+00	1.00E-04	1.12E-07
		1.00E-03	0.00E+00	1.00E-06	1.12E-09
		3.00E-05	0.00E+00	3.00E-08	3.36E-11
RHR Suction	7.71E-07	1.00E-01	7.45E-07	2.58E-08	2.92E-08
		1.00E-03	7.71E-07	2.58E-10	3.83E-09
		3.00E-05	7.71E-07	7.73E-12	3.59E-09
Vessel Head Spray	4.53E-08	1.00E-01	4.38E-08	1.51E-09	1.72E-09
		1.00E-03	4.53E-08	1.51E-11	2.25E-10
		3.00E-05	4.53E-08	4.54E-13	2.11E-10
Total	4.34E-03	1.00E-01	1.43E-06	1.01E-04	9.74E-07
		1.00E-03	1.46E-06	1.01E-06	1.65E-08
		3.00E-05	1.46E-06	3.03E-08	7.08E-09

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
CDF = Core Damage Frequency (/ry).

Table 5.3
Summary of Results for Peach Bottom - Logic System Functional Test at Shutdown

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.33E-05	1.00E-01	1.30E-07	3.00E-07	3.00E-07
		1.00E-03	1.33E-07	3.00E-09	3.62E-09
		3.00E-05	1.33E-07	8.99E-11	7.08E-10
CS	1.18E-05	1.00E-01	1.17E-07	1.52E-07	1.53E-07
		1.00E-03	1.18E-07	1.52E-09	2.07E-09
		3.00E-05	1.18E-07	4.56E-11	5.95E-10
HPCI	1.68E-04	1.00E-01	0.00E+00	3.40E-08	3.40E-08
		1.00E-03	0.00E+00	3.40E-10	3.40E-10
		3.00E-05	0.00E+00	1.02E-11	1.02E-11
RCIC	1.68E-04	1.00E-01	0.00E+00	3.40E-08	3.40E-08
		1.00E-03	0.00E+00	3.40E-10	3.40E-10
		3.00E-05	0.00E+00	1.02E-11	1.02E-11
Feedwater	1.00E-03	1.00E-01	0.00E+00	1.00E-04	1.12E-07
		1.00E-03	0.00E+00	1.00E-06	1.12E-09
		3.00E-05	0.00E+00	3.00E-08	3.36E-11
RHR Suction	7.71E-07	1.00E-01	7.45E-07	2.58E-08	2.92E-08
		1.00E-03	7.71E-07	2.58E-10	3.83E-09
		3.00E-05	7.71E-07	7.73E-12	3.59E-09
Vessel Head Spray	4.53E-08	1.00E-01	4.38E-08	1.51E-09	1.72E-09
		1.00E-03	4.53E-08	1.51E-11	2.25E-10
		3.00E-05	4.53E-08	4.54E-13	2.11E-10
Total	1.36E-03	1.00E-01	1.04E-06	1.01E-04	6.64E-07
		1.00E-03	1.07E-06	1.01E-06	1.15E-08
		3.00E-05	1.07E-06	3.02E-08	5.15E-09

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
CDF = Core Damage Frequency (/ry).

Table 5.4
Summary of Results for Peach Bottom - Leak Test AO Check
in HPCI and RCIC at Refueling

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.52E-03	1.00E-01	1.52E-05	2.66E-06	2.73E-06
		1.00E-03	1.52E-05	2.66E-08	9.73E-08
		3.00E-05	1.52E-05	7.99E-10	7.14E-08
CS	1.52E-03	1.00E-01	1.51E-05	2.08E-06	2.15E-06
		1.00E-03	1.52E-05	2.08E-08	9.11E-08
		3.00E-05	1.52E-05	6.23E-10	7.10E-08
HPCI	2.22E-03	1.00E-01	0.00E+00	1.54E-07	1.54E-07
		1.00E-03	0.00E+00	1.54E-09	1.54E-09
		3.00E-05	0.00E+00	4.61E-11	4.61E-11
RCIC	2.22E-03	1.00E-01	0.00E+00	1.54E-07	1.54E-07
		1.00E-03	0.00E+00	1.54E-09	1.54E-09
		3.00E-05	0.00E+00	4.61E-11	4.61E-11
Feedwater	1.00E-03	1.00E-01	0.00E+00	1.00E-04	1.12E-07
		1.00E-03	0.00E+00	1.00E-06	1.12E-09
		3.00E-05	0.00E+00	3.00E-08	3.36E-11
RHR Suction	7.71E-07	1.00E-01	7.45E-07	2.58E-08	2.92E-08
		1.00E-03	7.71E-07	2.58E-10	3.83E-09
		3.00E-05	7.71E-07	7.73E-12	3.59E-09
Vessel Head Spray	4.53E-08	1.00E-01	4.38E-08	1.51E-09	1.72E-09
		1.00E-03	4.53E-08	1.51E-11	2.25E-10
		3.00E-05	4.53E-08	4.54E-13	2.11E-10
Total	8.49E-03	1.00E-01	3.11E-05	1.05E-04	5.33E-06
		1.00E-03	3.12E-05	1.05E-06	1.97E-07
		3.00E-05	3.12E-05	3.15E-08	1.46E-07

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
CDF = Core Damage Frequency (/ry).

Table 5.5
Summary of Results for Peach Bottom — All Three Corrective Actions

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	8.88E-06	1.00E-01	8.73E-08	1.49E-07	1.50E-07
		1.00E-03	8.88E-08	1.49E-09	1.90E-09
		3.00E-05	8.88E-08	4.47E-11	4.57E-10
CS	7.40E-06	1.00E-01	7.40E-08	1.48E-09	1.82E-09
		1.00E-03	7.40E-08	1.48E-11	3.58E-10
		3.00E-05	7.40E-08	4.43E-13	3.44E-10
HPCI	5.05E-06	1.00E-01	0.00E+00	8.12E-10	8.12E-10
		1.00E-03	0.00E+00	8.12E-12	8.12E-12
		3.00E-05	0.00E+00	2.44E-13	2.44E-13
RCIC	5.05E-06	1.00E-01	0.00E+00	8.12E-10	8.12E-10
		1.00E-03	0.00E+00	8.12E-12	8.12E-12
		3.00E-05	0.00E+00	2.44E-13	2.44E-13
Feedwater	1.00E-03	1.00E-01	0.00E+00	1.00E-04	1.12E-07
		1.00E-03	0.00E+00	1.00E-06	1.12E-09
		3.00E-05	0.00E+00	3.00E-08	3.36E-11
RHR Suction	7.71E-07	1.00E-01	7.45E-07	2.58E-08	2.92E-08
		1.00E-03	7.71E-07	2.58E-10	3.83E-09
		3.00E-05	7.71E-07	7.73E-12	3.59E-09
Vessel Head Spray	4.53E-08	1.00E-01	4.38E-08	1.51E-09	1.72E-09
		1.00E-03	4.53E-08	1.51E-11	2.25E-10
		3.00E-05	4.53E-08	4.54E-13	2.11E-10
Total	1.03E-03	1.00E-01	9.50E-07	1.00E-04	2.96E-07
		1.00E-03	9.79E-07	1.00E-06	7.46E-09
		3.00E-05	9.79E-07	3.01E-08	4.63E-09

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
CDF = Core Damage Frequency (/ry).

Table 5.6
Summary of Results for Nine Mile Point-2 - Base Case

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.33E-05	1.00E-01	7.85E-06	2.24E-07	2.25E-07
		1.00E-03	7.99E-06	2.24E-09	3.37E-09
		3.00E-05	7.99E-06	6.71E-11	1.20E-09
LPCS	3.69E-06	1.00E-01	2.22E-06	7.38E-10	1.05E-09
		1.00E-03	2.22E-06	7.38E-12	3.21E-10
		3.00E-05	2.22E-06	2.22E-13	3.14E-10
SDC Return	8.86E-06	1.00E-01	5.24E-06	1.49E-07	1.50E-07
		1.00E-03	5.33E-06	1.49E-09	2.24E-09
		3.00E-05	5.33E-06	4.47E-11	7.97E-10
HPCS	2.65E-07	1.00E-01	2.65E-07	3.25E-13	5.31E-11
		1.00E-03	2.65E-07	3.25E-15	5.28E-11
		3.00E-05	2.65E-07	9.75E-17	5.28E-11
Vessel Head Spray	4.35E-06	1.00E-01	5.05E-08	5.34E-11	2.74E-10
		1.00E-03	5.05E-08	5.34E-13	2.21E-10
		3.00E-05	5.05E-08	1.60E-14	2.20E-10
Feedwater	1.00E-03	1.00E-01	0.00E+00	1.00E-04	1.12E-07
		1.00E-03	0.00E+00	1.00E-06	1.12E-09
		3.00E-05	0.00E+00	3.00E-08	3.36E-11
RHR Suction	7.71E-07	1.00E-01	7.45E-07	2.58E-08	2.58E-08
		1.00E-03	7.71E-07	2.58E-10	3.41E-10
		3.00E-05	7.71E-07	7.73E-12	9.10E-11
Steam Condensing	8.90E-03	1.00E-01	1.73E-05	2.22E-04	2.22E-04
		1.00E-03	1.78E-05	2.22E-06	2.23E-06
		3.00E-05	1.78E-05	6.67E-08	6.86E-08
Total	9.93E-03	1.00E-01	3.37E-05	3.23E-04	2.23E-04
		1.00E-03	3.44E-05	3.23E-06	2.23E-06
		3.00E-05	3.44E-05	9.68E-08	7.13E-08

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
CDF = Core Damage Frequency (/ry).

Table 5.7
Summary of Results for Nine Mile Point-2 - Do Not Cycle F052
and F218 at Power

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.33E-05	1.00E-01	7.85E-06	2.24E-07	2.25E-07
		1.00E-03	7.99E-06	2.24E-09	3.37E-09
		3.00E-05	7.99E-06	6.71E-11	1.20E-09
LPCS	3.69E-06	1.00E-01	2.22E-06	7.38E-10	1.05E-09
		1.00E-03	2.22E-06	7.38E-12	3.21E-10
		3.00E-05	2.22E-06	2.22E-13	3.14E-10
SDC Return	8.86E-06	1.00E-01	5.24E-06	1.49E-07	1.50E-07
		1.00E-03	5.33E-06	1.49E-09	2.24E-09
		3.00E-05	5.33E-06	4.47E-11	7.97E-10
HPCS	2.65E-07	1.00E-01	2.65E-07	3.25E-13	5.31E-11
		1.00E-03	2.65E-07	3.25E-15	5.28E-11
		3.00E-05	2.65E-07	9.75E-17	5.28E-11
Vessel Head Spray	4.35E-06	1.00E-01	5.05E-08	5.34E-11	2.74E-10
		1.00E-03	5.05E-08	5.34E-13	2.21E-10
		3.00E-05	5.05E-08	1.60E-14	2.20E-10
Feedwater	1.00E-03	1.00E-01	0.00E+00	1.00E-04	1.12E-07
		1.00E-03	0.00E+00	1.00E-06	1.12E-09
		3.00E-05	0.00E+00	3.00E-08	3.36E-11
RHR Suction	7.71E-07	1.00E-01	7.45E-07	2.58E-08	2.58E-08
		1.00E-03	7.71E-07	2.58E-10	3.41E-10
		3.00E-05	7.71E-07	7.73E-12	9.10E-11
Steam Condensing	2.42E-03	1.00E-01	4.71E-06	6.04E-05	6.04E-05
		1.00E-03	4.83E-06	6.04E-07	6.05E-07
		3.00E-05	4.83E-06	1.81E-08	1.86E-08
Total	3.45E-03	1.00E-01	2.11E-05	1.61E-04	6.09E-05
		1.00E-03	2.14E-05	1.61E-06	6.12E-07
		3.00E-05	2.15E-05	4.82E-08	2.13E-08

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
CDF = Core Damage Frequency (/ry).

Table 5.8
Summary of Results for Nine Mile Point-2 - Do Not Cycle F087 at Power

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.33E-05	1.00E-01	7.85E-06	2.24E-07	2.25E-07
		1.00E-03	7.99E-06	2.24E-09	3.37E-09
		3.00E-05	7.99E-06	6.71E-11	1.20E-09
LPCS	3.69E-06	1.00E-01	2.22E-06	7.38E-10	1.05E-09
		1.00E-03	2.22E-06	7.38E-12	3.21E-10
		3.00E-05	2.22E-06	2.22E-13	3.14E-10
SDC Return	8.86E-06	1.00E-01	5.24E-06	1.49E-07	1.50E-07
		1.00E-03	5.33E-06	1.49E-09	2.24E-09
		3.00E-05	5.33E-06	4.47E-11	7.97E-10
HPCS	2.65E-07	1.00E-01	2.65E-07	3.25E-13	5.31E-11
		1.00E-03	2.65E-07	3.25E-15	5.28E-11
		3.00E-05	2.65E-07	9.75E-17	5.28E-11
Vessel Head Spray	4.35E-06	1.00E-01	5.05E-08	5.34E-11	2.74E-10
		1.00E-03	5.05E-08	5.34E-13	2.21E-10
		3.00E-05	5.05E-08	1.60E-14	2.20E-10
Feedwater	1.00E-03	1.00E-01	0.00E+00	1.00E-04	1.12E-07
		1.00E-03	0.00E+00	1.00E-06	1.12E-09
		3.00E-05	0.00E+00	3.00E-08	3.36E-11
RHR Suction	7.71E-07	1.00E-01	7.45E-07	2.58E-08	2.58E-08
		1.00E-03	7.71E-07	2.58E-10	3.41E-10
		3.00E-05	7.71E-07	7.73E-12	9.10E-11
Steam Condensing	6.50E-03	1.00E-01	1.27E-05	1.62E-04	1.62E-04
		1.00E-03	1.30E-05	1.62E-06	1.63E-06
		3.00E-05	1.30E-05	4.87E-08	5.01E-08
Total	7.53E-03	1.00E-01	2.90E-05	2.63E-04	1.63E-04
		1.00E-03	2.96E-05	2.63E-06	1.63E-06
		3.00E-05	2.96E-05	7.88E-08	5.28E-08

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
CDF = Core Damage Frequency (/ry).

Table 5.9
Summary of Results for Nine Mile Point-2 - Both Corrective Action

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.33E-05	1.00E-01	7.85E-06	2.24E-07	2.25E-07
		1.00E-03	7.99E-06	2.24E-09	3.37E-09
		3.00E-05	7.99E-06	6.71E-11	1.20E-09
LPCS	3.69E-06	1.00E-01	2.22E-06	7.38E-10	1.05E-09
		1.00E-03	2.22E-06	7.38E-12	3.21E-10
		3.00E-05	2.22E-06	2.22E-13	3.14E-10
SDC Return	8.86E-06	1.00E-01	5.24E-06	1.49E-07	1.50E-07
		1.00E-03	5.33E-06	1.49E-09	2.24E-09
		3.00E-05	5.33E-06	4.47E-11	7.97E-10
HPCS	2.65E-07	1.00E-01	2.65E-07	3.25E-13	5.31E-11
		1.00E-03	2.65E-07	3.25E-15	5.28E-11
		3.00E-05	2.65E-07	9.75E-17	5.28E-11
Vessel Head Spray	4.35E-06	1.00E-01	5.05E-08	5.34E-11	2.74E-10
		1.00E-03	5.05E-08	5.34E-13	2.21E-10
		3.00E-05	5.05E-08	1.60E-14	2.20E-10
Feedwater	1.00E-03	1.00E-01	0.00E+00	1.00E-04	1.12E-07
		1.00E-03	0.00E+00	1.00E-06	1.12E-09
		3.00E-05	0.00E+00	3.00E-08	3.36E-11
RHR Suction	7.71E-07	1.00E-01	7.45E-07	2.58E-08	2.58E-08
		1.00E-03	7.71E-07	2.58E-10	3.41E-10
		3.00E-05	7.71E-07	7.73E-12	9.10E-11
Steam Condensing	1.62E-05	1.00E-01	3.14E-08	4.00E-07	4.00E-07
		1.00E-03	3.22E-08	4.00E-09	4.01E-09
		3.00E-05	3.22E-08	1.20E-10	1.24E-10
Total	1.05E-03	1.00E-01	1.64E-05	1.01E-04	9.14E-07
		1.00E-03	1.67E-05	1.01E-06	1.17E-08
		3.00E-05	1.67E-05	3.02E-08	2.83E-09

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
CDF = Core Damage Frequency (/ry).

Table 5.10
Summary of Results for Quad Cities -Base Case

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	2.07E-03	1.00E-01	2.07E-05	6.00E-06	6.11E-06
		1.00E-03	2.07E-05	6.00E-08	1.71E-07
		3.00E-05	2.07E-05	1.80E-09	1.13E-07
CS	2.01E-03	1.00E-01	2.00E-05	3.04E-06	3.15E-06
		1.00E-03	2.01E-05	3.04E-08	1.38E-07
		3.00E-05	2.01E-05	9.13E-10	1.09E-07
HPCI	9.03E-04	1.00E-01	0.00E+00	9.42E-08	9.42E-08
		1.00E-03	0.00E+00	9.42E-10	9.42E-10
		3.00E-05	0.00E+00	2.82E-11	2.82E-11
RCIC	9.03E-04	1.00E-01	0.00E+00	9.42E-08	9.42E-08
		1.00E-03	0.00E+00	9.42E-10	9.42E-10
		3.00E-05	0.00E+00	2.82E-11	2.82E-11
Feedwater	1.00E-03	1.00E-01	0.00E+00	1.00E-04	1.12E-07
		1.00E-03	0.00E+00	1.00E-06	1.12E-09
		3.00E-05	0.00E+00	3.00E-08	3.36E-11
RHR Suction	7.71E-07	1.00E-01	7.45E-07	2.58E-08	2.97E-08
		1.00E-03	7.71E-07	2.58E-10	4.39E-09
		3.00E-05	7.71E-07	7.73E-12	4.14E-09
Vessel Head Spray	4.53E-08	1.00E-01	4.38E-08	1.51E-09	1.75E-09
		1.00E-03	4.53E-08	1.51E-11	2.58E-10
		3.00E-05	4.53E-08	4.54E-13	2.43E-10
Total	6.89E-03	1.00E-01	4.15E-05	1.09E-04	9.59E-06
		1.00E-03	4.16E-05	1.09E-06	3.17E-07
		3.00E-05	4.16E-05	3.28E-08	2.26E-07

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
CDF = Core Damage Frequency (/ry).

Table 5.11
Summary of Results for Quad Cities - Leak Test AO Check in ECCS

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.53E-03	1.00E-01	1.53E-05	6.00E-07	6.82E-07
		1.00E-03	1.53E-05	6.00E-09	8.80E-08
		3.00E-05	1.53E-05	1.80E-10	8.22E-08
CS	1.52E-03	1.00E-01	1.52E-05	3.04E-07	3.86E-07
		1.00E-03	1.52E-05	3.04E-09	8.47E-08
		3.00E-05	1.52E-05	9.13E-11	8.17E-08
HPCI	7.43E-04	1.00E-01	0.00E+00	7.45E-08	7.45E-08
		1.00E-03	0.00E+00	7.45E-10	7.45E-10
		3.00E-05	0.00E+00	2.24E-11	2.24E-11
RCIC	7.43E-04	1.00E-01	0.00E+00	7.45E-08	7.45E-08
		1.00E-03	0.00E+00	7.45E-10	7.45E-10
		3.00E-05	0.00E+00	2.24E-11	2.24E-11
Feedwater	1.00E-03	1.00E-01	0.00E+00	1.00E-04	1.12E-07
		1.00E-03	0.00E+00	1.00E-06	1.12E-09
		3.00E-05	0.00E+00	3.00E-08	3.36E-11
RHR Suction	7.71E-07	1.00E-01	7.45E-07	2.58E-08	2.97E-08
		1.00E-03	7.71E-07	2.58E-10	4.39E-09
		3.00E-05	7.71E-07	7.73E-12	4.14E-09
Vessel Head Spray	4.53E-08	1.00E-01	4.38E-08	1.51E-09	1.75E-09
		1.00E-03	4.53E-08	1.51E-11	2.58E-10
		3.00E-05	4.53E-08	4.54E-13	2.43E-10
Total	5.54E-03	1.00E-01	3.13E-05	1.01E-04	1.36E-06
		1.00E-03	3.13E-05	1.01E-06	1.80E-07
		3.00E-05	3.14E-05	3.03E-08	1.68E-07

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
CDF = Core Damage Frequency (/ry).

Table 5.12
Summary of Results for Quad Cities - Leak AO Check After Maintenance

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.87E-03	1.00E-01	1.87E-05	2.98E-06	3.08E-06
		1.00E-03	1.87E-05	2.98E-08	1.30E-07
		3.00E-05	1.87E-05	8.95E-10	1.01E-07
CS	1.81E-03	1.00E-01	1.81E-05	2.95E-08	1.26E-07
		1.00E-03	1.81E-05	2.95E-10	9.71E-08
		3.00E-05	1.81E-05	8.86E-12	9.68E-08
HPCI	8.02E-04	1.00E-01	0.00E+00	7.64E-08	7.64E-08
		1.00E-03	0.00E+00	7.64E-10	7.64E-10
		3.00E-05	0.00E+00	2.29E-11	2.29E-11
RCIC	8.02E-04	1.00E-01	0.00E+00	7.64E-08	7.64E-08
		1.00E-03	0.00E+00	7.64E-10	7.64E-10
		3.00E-05	0.00E+00	2.29E-11	2.29E-11
Feedwater	1.00E-03	1.00E-01	0.00E+00	1.00E-04	1.12E-07
		1.00E-03	0.00E+00	1.00E-06	1.12E-09
		3.00E-05	0.00E+00	3.00E-08	3.36E-11
RHR Suction	7.71E-07	1.00E-01	7.45E-07	2.58E-08	2.97E-08
		1.00E-03	7.71E-07	2.58E-10	4.39E-09
		3.00E-05	7.71E-07	7.73E-12	4.14E-09
Vessel Head Spray	4.53E-08	1.00E-01	4.38E-08	1.51E-09	1.75E-09
		1.00E-03	4.53E-08	1.51E-11	2.58E-10
		3.00E-05	4.53E-08	4.54E-13	2.43E-10
Total	6.28E-03	1.00E-01	3.75E-05	1.03E-04	3.51E-06
		1.00E-03	3.76E-05	1.03E-06	2.35E-07
		3.00E-05	3.76E-05	3.10E-08	2.03E-07

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
CDF = Core Damage Frequency (/ry).

Table 5.13
Summary of Results for Quad Cities - Both Corrective Actions

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.51E-03	1.00E-01	1.51E-05	2.98E-07	3.79E-07
		1.00E-03	1.51E-05	2.98E-09	8.39E-08
		3.00E-05	1.51E-05	8.95E-11	8.10E-08
CS	1.50E-03	1.00E-01	1.50E-05	2.95E-09	8.35E-08
		1.00E-03	1.50E-05	2.95E-11	8.06E-08
		3.00E-05	1.50E-05	8.86E-13	8.06E-08
HPCI	7.38E-04	1.00E-01	0.00E+00	7.36E-08	7.36E-08
		1.00E-03	0.00E+00	7.36E-10	7.36E-10
		3.00E-05	0.00E+00	2.21E-11	2.21E-11
RCIC	7.38E-04	1.00E-01	0.00E+00	7.36E-08	7.36E-08
		1.00E-03	0.00E+00	7.36E-10	7.36E-10
		3.00E-05	0.00E+00	2.21E-11	2.21E-11
Feedwater	1.00E-03	1.00E-01	0.00E+00	1.00E-04	1.12E-07
		1.00E-03	0.00E+00	1.00E-06	1.12E-09
		3.00E-05	0.00E+00	3.00E-08	3.36E-11
RHR Suction	7.71E-07	1.00E-01	7.45E-07	2.58E-08	2.97E-08
		1.00E-03	7.71E-07	2.58E-10	4.39E-09
		3.00E-05	7.71E-07	7.73E-12	4.14E-09
Vessel Head Spray	4.53E-08	1.00E-01	4.38E-08	1.51E-09	1.75E-09
		1.00E-03	4.53E-08	1.51E-11	2.58E-10
		3.00E-05	4.53E-08	4.54E-13	2.43E-10
Total	5.49E-03	1.00E-01	3.09E-05	1.00E-04	7.54E-07
		1.00E-03	3.09E-05	1.00E-06	1.72E-07
		3.00E-05	3.09E-05	3.01E-08	1.66E-07

Notes: f(OP) = Frequency of Overpressurization (/ry).
P(Rupture) = Probability of Major Pipe Rupture.
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
CDF = Core Damage Frequency (/ry).

APPENDIX A: Information Collected for Interfacing Lines

A.1 Interfacing Lines at Peach Bottom

The interfacing lines identified for Peach Bottom are the following:

a. LPCI Injection Lines
b. Shutdown Cooling Suction Line
c. Reactor Pressure Vessel Head Spray
d. Core Spray Injection Lines
e. HPCI Pump Suction
f. RCIC Pump Suction

These interfacing lines are shown in Figures A.1.a–A.1.f. Tables A.1.a–A.1.f list some data collected for them. Table A.1.g lists the lines penetrating the containment. The single character code in the first column of the table denotes the disposition of the line. An asterisk indicates that the line is considered in the study. A letter means that the line is not further considered, based on the screening criterion denoted by the same letter in Section 2.1.

A.1.1 LPCI Injection Lines

The RHR system consists of two loops. Each loop consists of two heat exchangers, two pumps, two suppression pool suction lines, and one injection line. The two loops are identical except that loop B has connections with high pressure service water and the fuel pool, and that loop A is connected to the vessel head spray. The discharge sides of the two loops are crossconnected with a closed deenergized valve, MO-10-20.

A.1.1.1 Automatic and Manual Control

RHR pumps start automatically on low vessel level or high drywell pressure and low reactor pressure. The suction paths from the suppression pool are normally open. Outboard injection valve 154 is normally open.

Inboard injection valve 25 is normally closed. When the automatic actuation signal is present, an open signal is sent to the injection valves in both loops. Upon receiving the open signal, the normally closed injection valves, 25A and 25B, will open if the reactor pressure is low. A timer cancels the LPCI signals to the injection valves, 154A and 154B, after a delay time long enough to permit satisfactory operation of the LPCIS. The cancellation of the signals allows the operator to divert the water for other post accident uses such as torus cooling, torus spray or drywell spray.

Without the low vessel pressure signal, the two injection valves in each loop are interlocked. One valve can be manually opened only if the other valve is closed.

A.1.1.2 Indications of Overpressurization or Interfacing LOCA

In the event that the isolation valves 46 and 25 fail to isolate, the low pressure piping that will be overpressurized is bounded by valves 20, 25, 26, 33 (Loop A only), 39, 48, 177 (Loop B only), and 180 (Loop B only). The design pressure of the low pressure piping is 150 psi. There are two one-inch relief valves that discharge to the clean rad-waste system. When an interfacing LOCA occurs, the following indication may be available to the operators, in addition to the low vessel level alarm and the starting of the standby core cooling systems,

1. RHR Pump Room Flooding Alarm in the Control Room - Liquid level switches are set to detect water level 6" above the floor.

2. High RHR Room Ambient Temperature - Room temperature is alarmed and indicated in the control room.

3. Room ventilation temperature is indicated.

4. The reactor building drain sump pumps will start automatically on high level. High high level in the drain sump also actuates an alarm in the main control room.

5. High pump discharge header pressure is alarmed in the control room.

6. High radiation in reactor building ventilation exhaust alarm in the control room.

7. High RHR pump room radiation and high reactor building sump area radiation alarms in the control room.

A.1.2 Shutdown Heat Removal Suction from Recirculation

A.1.2.1 Automatic and Manual Control

Shutdown cooling is initiated manually when the nuclear system pressure has decreased to a point where the steam supply pressure is not sufficient to maintain the turbine shaft gland seals, and vacuum in the main condenser can not be maintained. Reactor coolant is pumped by the RHR pumps from one of the recirculation loops through the RHR heat exchangers. Reactor coolant is returned to the vessel via either recirculation loop. Part of the flow may be diverted to a spray nozzle in the reactor head. The isolation valves 17 and 18 can be manually opened in control room only if the vessel pressure is in shutdown cooling range. They receive automatic isolation signals on low vessel level or high drywell pressure or high vessel pressure (exceeding 625 psig).

A.1.2.2 Indications of Overpressurization or Interfacing LOCA

In the case that the isolation valves 17 and 18 fail to isolate, the low pressure piping that will be overpressurized is bounded by valves 17, 520, 51, 15A, 15B, 15C, and 15D. Its design pressure is 150 psi. There is one one-inch relief valve in this pipe section that discharges to clean rad-waste system. The indications for an interfacing LOCA are the same as those for LPCI lines, except that high suction pressure alarm replaces high discharge header pressure alarm.

A.1.3 Vessel Head Spray

A.1.3.1 Manual and Automatic Control

Vessel head spray may be used in the shutdown cooling mode of the RHR system. Isolation valves 32 and 33 can be manually opened only if vessel pressure is in the shutdown cooling range. They receive an automatic isolation signal on low vessel level or high drywell pressure or high vessel pressure (exceeding 625 psig).

A.1.3.2 Indications of Overpressurization or Interfacing LOCA

If the check valve down stream of the isolation valves as well as both isolation valves fails, the section of low pressure piping that will be overpressurized is the same as that for LPCI loop A. Therefore, the same indications will be available to the operators. The only difference is that both isolation valves in the head spray line receive automatic isolation signals.

A.1.4 Core Spray Injection Lines

Core spray system consists of two identical loops. Each loop consists of two pumps with separate suction lines from the suppression pool.

A.1.4.1 Automatic and Manual Control

Core spray pumps start on low vessel level signal or high drywell pressure and low vessel pressure. Each pump has a separate suction line from the suppression pool with the suction valve normally open. The testable check valve, 13, and the inboard injection valve, 12, are normally closed. The outboard injection valve, 11, is normally open. Both injection valves open automatically when drywell pressure is high or vessel level is low and vessel pressure is low. Without automatic open signal, the two injection valves are interlocked. One valve can be opened only if the other valve is closed.

A.1.4.2 Indication of Overpressurization or Interfacing LOCA

If the isolation valves in the core spray injection lines fail open, the section or piping that will be overpressurized is bounded by valves 12, 10, 26, 23, and 4225. This section has a design pressure of 450 psi. A two-inch relief valve is located in this pipe section. It discharges to clean rad-waste. When an interfacing LOCA occurs, in addition to the low vessel level alarm, the following indications will be available.

1. Core Spray Pump Room Flooding Alarm in the Control Room - Liquid level switches are set to detect water level 6" above the floor.

2. The reactor building drain sump pumps will start automatically on high level. It also actuates an alarm in the main control room on high high level in the sump.

3. Pump discharge pressure and suction pressure are indicated locally.

4. A pressure switch is located between valves 11 and 12. An alarm in the control room will indicate the leakage through valves 12 and 13.

5. High radiation in reactor building ventilation exhaust alarm in the control room.

6. High core spray pump room radiation and high reactor building sump area radiation alarms in the control room.

A.1.5 HPCI Pump Suction

A.1.5.1 Automatic and Manual Control

The HPCI system is actuated on high drywell pressure or low vessel level. Inboard injection valve 19 is normally closed and outboard injection valve 20 is normally open. Both valves receive an open signal on system actuation. They can be remote manually controlled from the control room. Pump suction from the

condensate storage tank is normally open. Suction valves 58 and 57 from the suppression pool are normally closed. They will be automatically opened when the CST level is low. After they are fully open, the suction valve, 17, from the CST will be closed automatically. Suction valves from the suppression pool and the two steam isolation valves are isolated by excess steam supply line space temperature or high steam supply line pressure differential.

A.1.5.2 Indication of Overpressurization or Interfacing LOCA

If the feedwater inboard check valve (CV28A) and valves 18, 19, and 20 fail open, reactor coolant will overpressurize the piping on the suction side of the pump. It is bounded by valves 130, 131, 32, and 57. This pipe section has a design pressure of 150 psi. A one-and-one-half-inch relief valve is located in this section. It discharges to clean rad-waste.

If an interfacing LOCA occurs, in addition to low vessel level alarm, the following indications are available.

1. HPIC Pump Room Flooding Alarm in the Control Room - Level switches are set to detect water level 6" above the floor.

2. High HPCI Pump Room Temperature - High room temperature is indicated and alarmed in the control room. It also actúate isolation of the HPCI system which is also alarmed in the control room.

3. Room ventilation temperature is indicated.

4. The reactor building drain sump pump will start automatically on high level. It also actuate an alarm in the control room on high high sump level.

5. Condensate storage tank low level alarm in the control room.

6. HPCI pump high suction pressure alarm in the control room.

7. High radiation in reactor building ventilation exhaust alarm in the control room.

8. High HPCI pump room radiation and high reactor building sump area radiation alarms in the control room.

A.1.6 RCIC Suction - Reactor Core Isolation Cooling System

A.1.6.1 Automatic and Manual Control

The system is started on low vessel level. Suction path from the condensate storage tank is normally open. Its suction valve receives an open signal on system auto initiation. The outboard injection valves, 20, is normally open. The inboard injection valve, 21, is normally closed. Both injection valves receive an automatic open signal on system auto initiation. When CST level becomes low, automatic switch-over from CST to suppression pool will take place. After the suction valves from the suppression pool are fully open, the suction valve from the CST will be closed automatically.

A.1.6.2 Indications for Overpressurization or Interfacing LOCA

When inboard check valve (CV28B) and isolation valves 20, 21, and 22 fail open, the RCIC pump suction will be overpressurized. The overpressurized section is bounded by the RCIC pump and valves 39 and 19. It has a design pressure of 150 psi. There is a one-inch relief valve in this pipe section. It discharges to clean rad waste. When an interfacing LOCA occurs in this pipe section, in addition to the low vessel level alarm and the actuation of standby core cooling system, the following indications will be available.

1. RCIC Pump Room Flooding Alarm in the Control Room - Liquid level switches are set to detect water level 6" above the floor.

2. RCIC pump room temperature is indicated in the control room. High room temperature is alarmed in the control room. It also isolate the RCIC system.

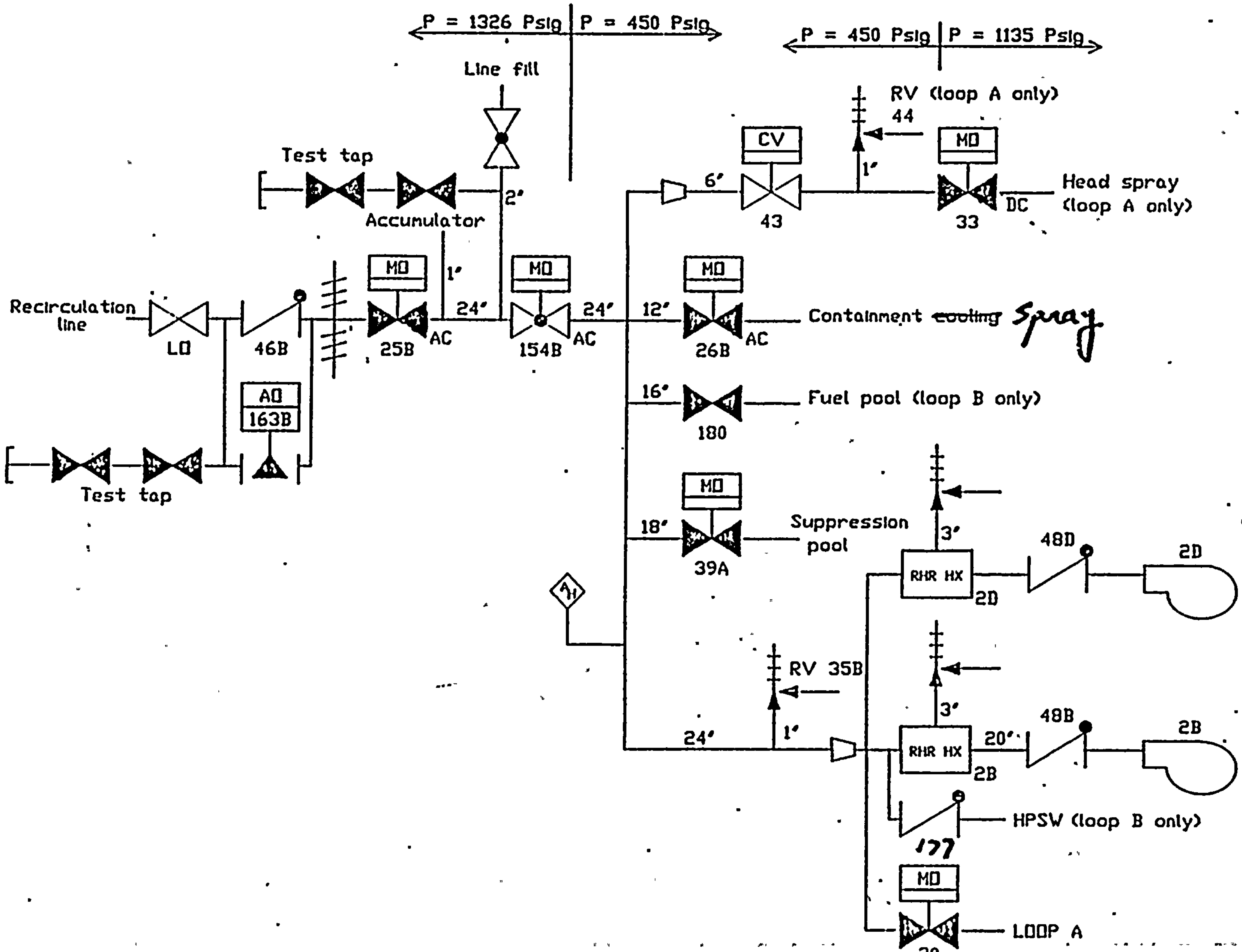

Figure A.1a LPCI (RHR) injection lines.

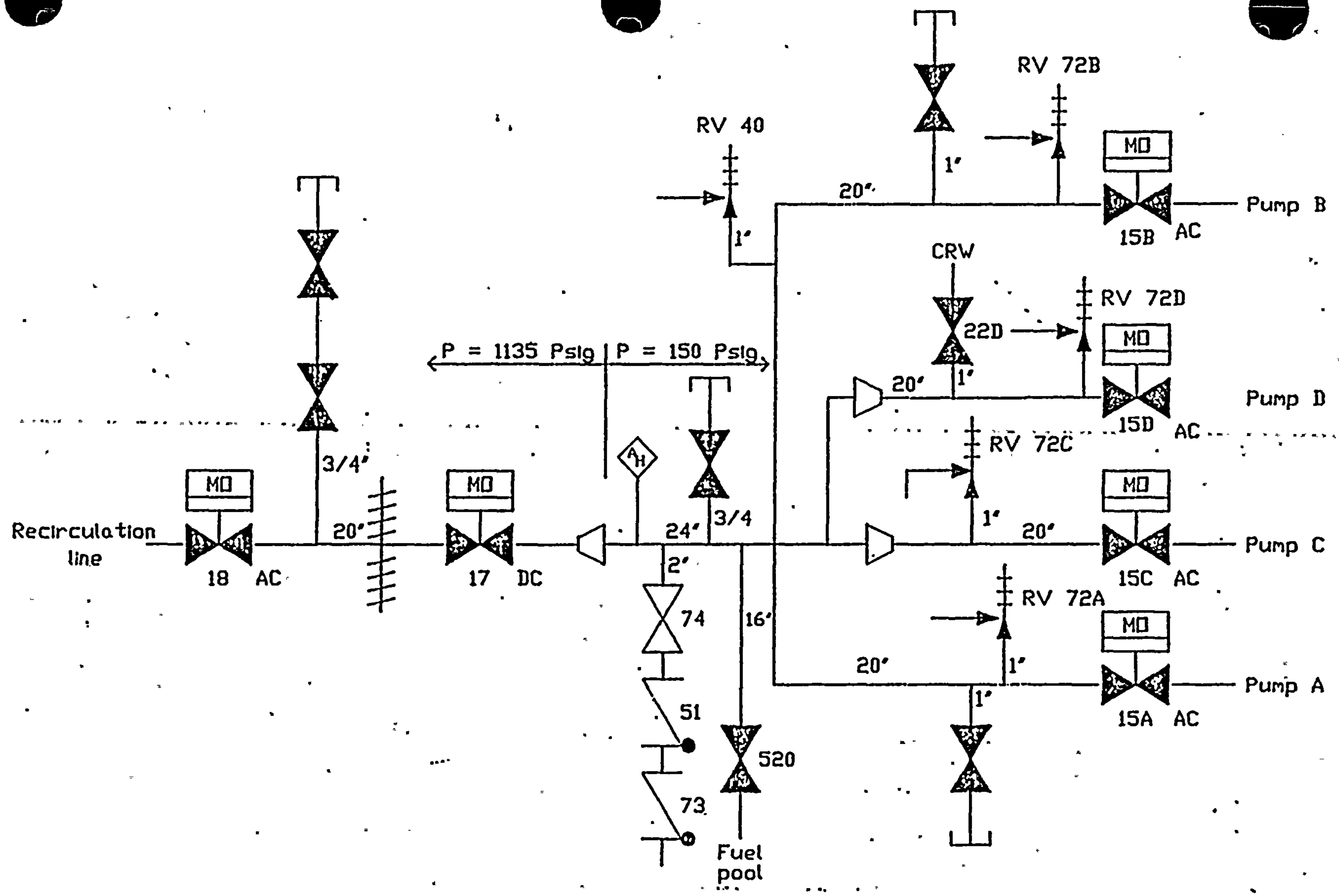

Figure A.1b Shutdown cooling suction (RHR).

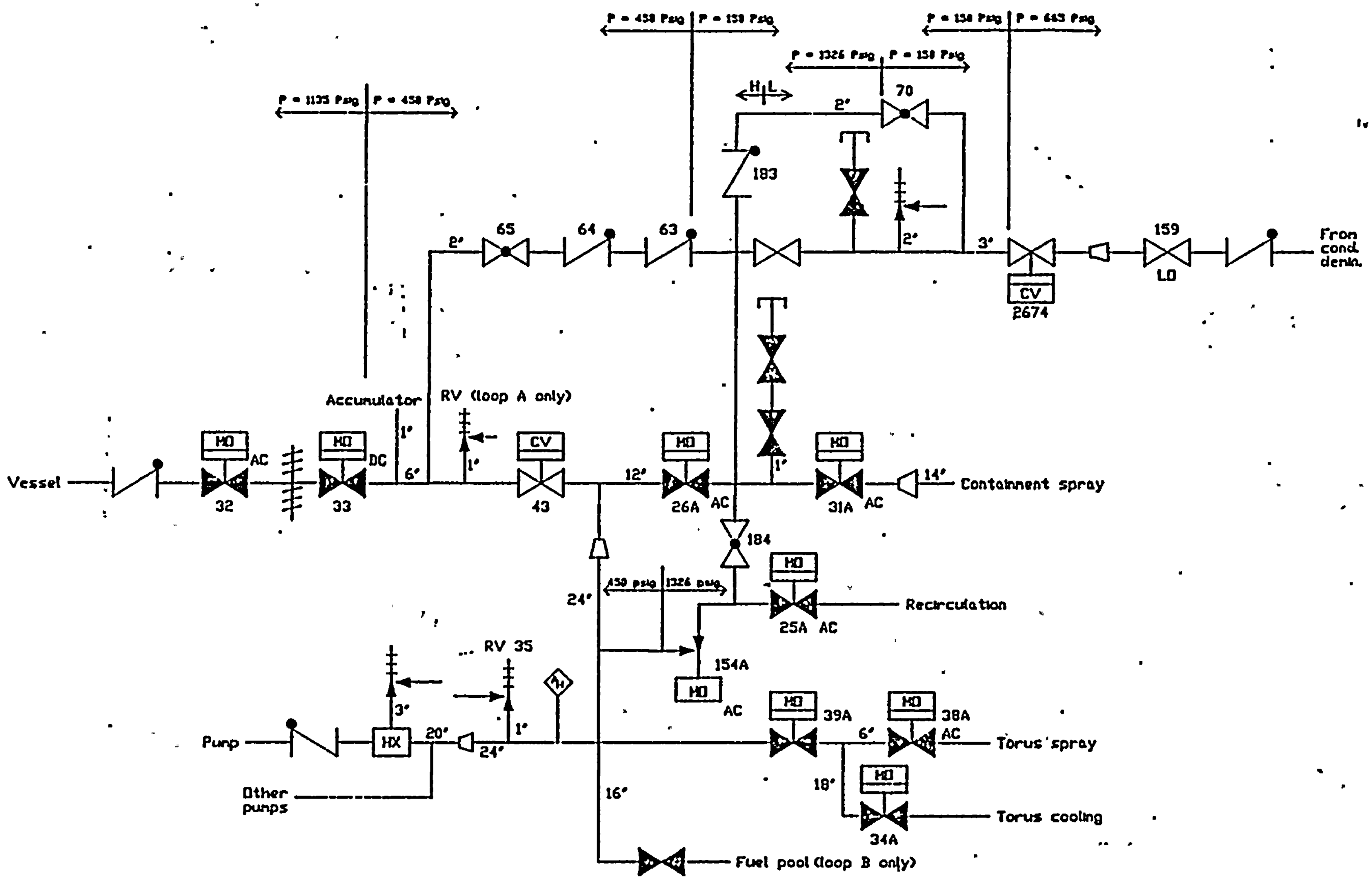

Figure A.1c Vessel head spray (RHR).

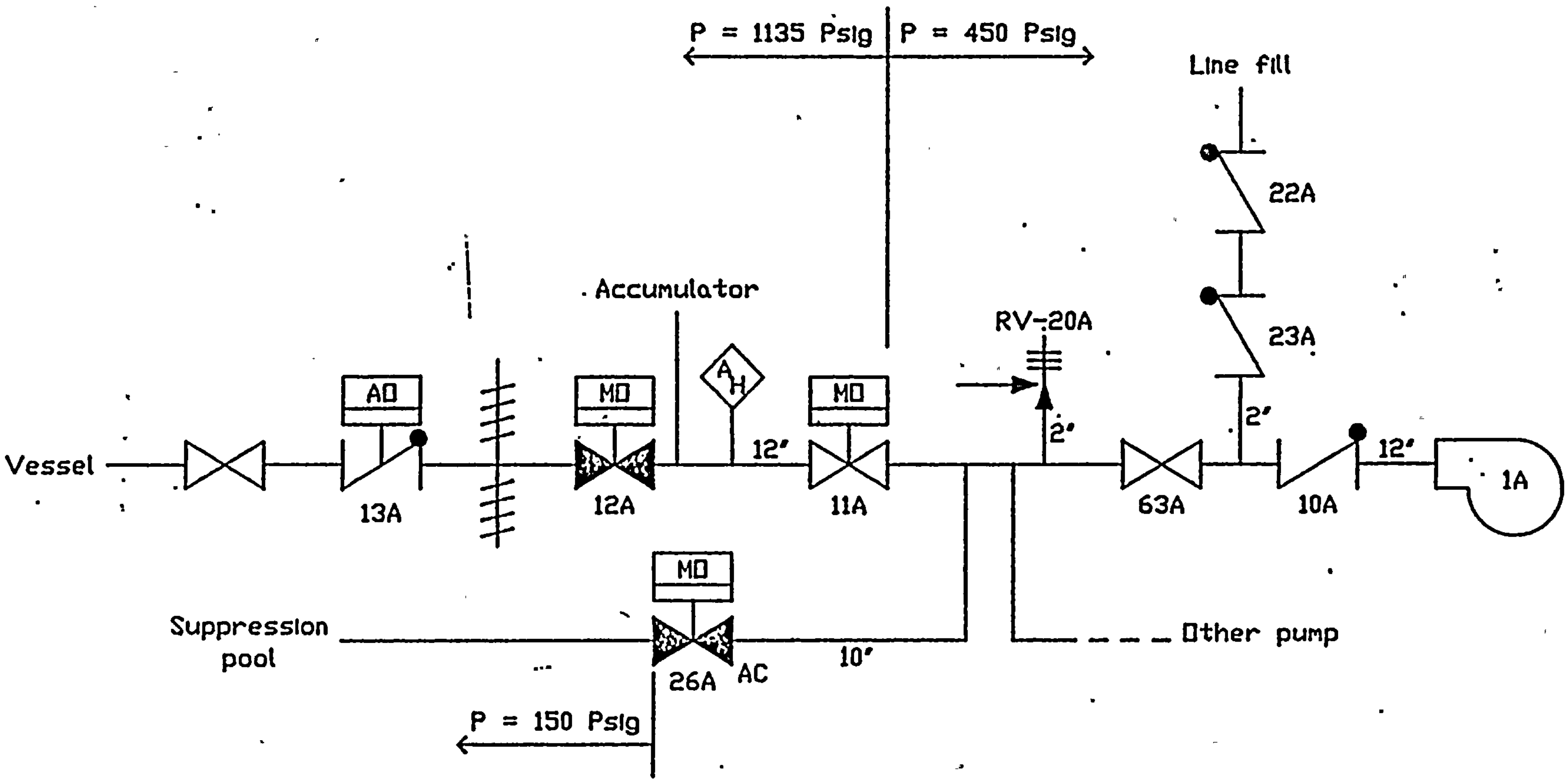

Figure A.1d . Core spray injection lines.

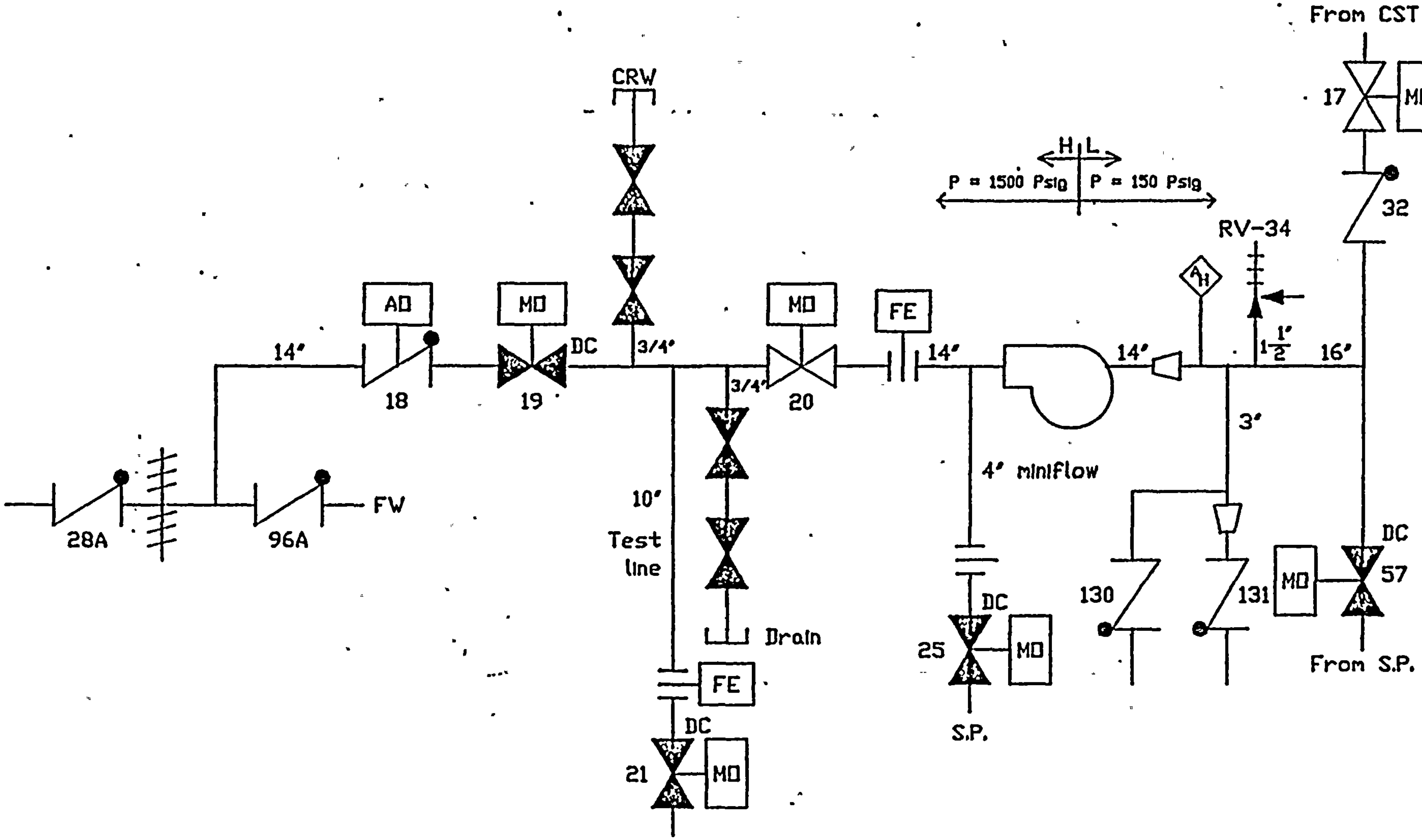

Figure A.1e HPCI suction.

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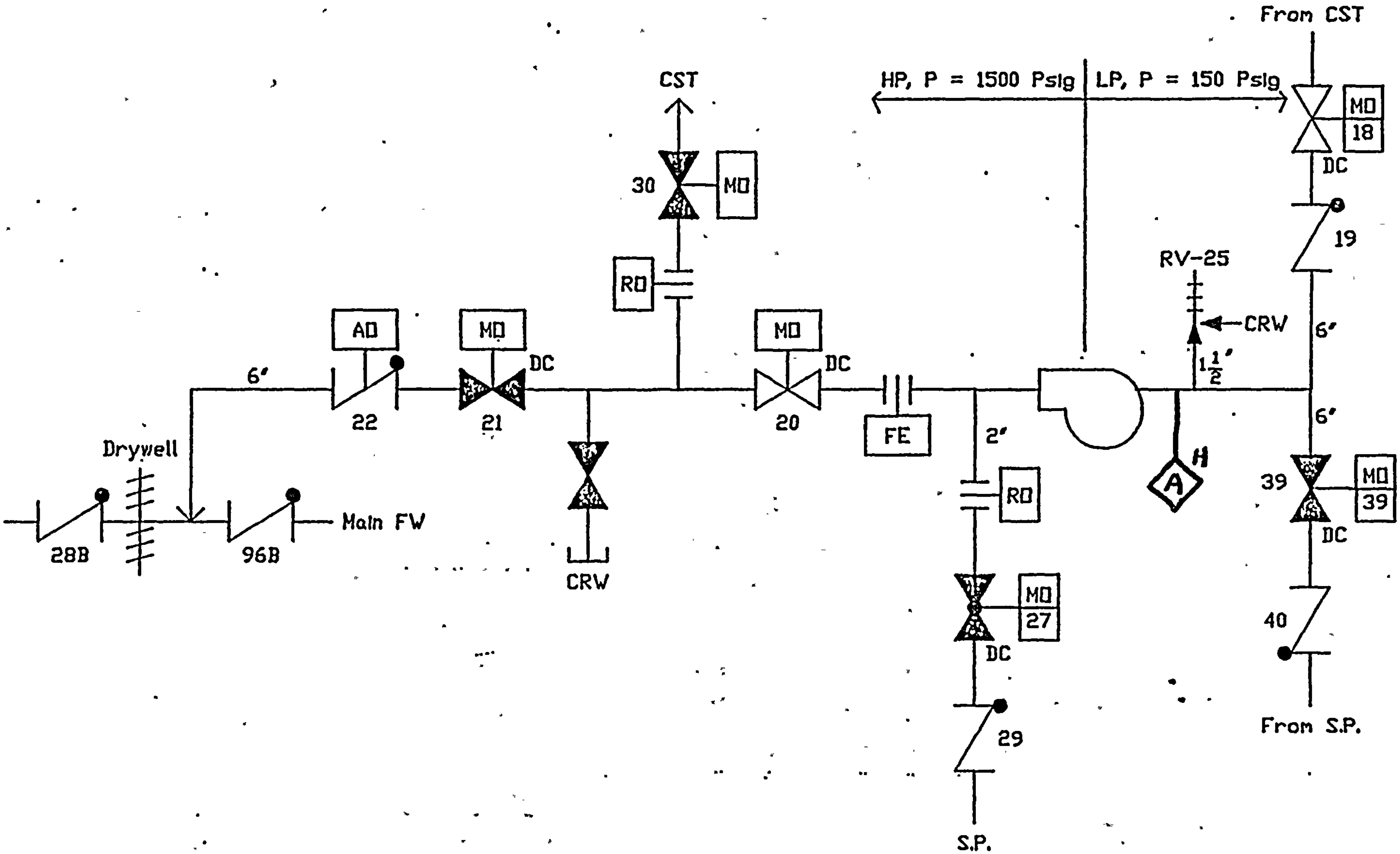

Figure A.1f RCIC suction.

Table A.1.a
LPCI (RHR) Injection Lines

1.	Number of lines -	2		
2.	Line size -	24"		
3.	Valve number -	46A,B	25A,B***	154A,B***
4.	Valve location -	I	0	0
5.	Valve type -	AO Check	MO Gate	MO Globe
6.	Valve operator -	air	ac	ac
7.	Valve normal position -	closed	closed	open
8.	Power failure position -	——	closed	open
9.	Isolation signals -	——	*	*
10.	Normal flow direction -	in	in	in
11.	Surveillance requirement -	+	**	**
12.	Pump surveillance requirement -	manually started monthly, auto actuation/operating cycle, flow tested/ 3 months		
13.	Relief valves -	RV-35A,B 50 gpm at 425 psig, RV-44 50 gpm at 400 psig (Loop A only), and two 3" relief valves.		

*Can be opened manually if reactor pressure is low or the other isolation valve is closed.
**Stroke tested monthly, actuation tested every operating cycle, LLRT/cycle operational hydro test/cycle (25A, B only).
***Valves are interlocked.
+Leak rate tested during operational hydro every cycle.

Table A.1.b
Shutdown Cooling Suction (RHR)

1.	Number of lines -	1	
2.	Line size -	20"	
3.	Valve number -	18	17
4.	Valve location -	in	out
5.	Valve type -	MO Gate	MO Gate
6.	Valve operator -	ac	dc
7.	Valve normal position -	closed	closed
8.	Power failure position -	closed	closed
9.	Isolation signals -	high drywell pressure or low vessel level or high vessel pressure	
10.	Normal flow direction -	out	out
11.	Surveillance requirement -	auto isolation/cycle, stroked/shutdown longer than 48 hours, LLRT/cycle, operational hydro/cycle	
12.	Pump surveillance requirement -	flow tested/3 months, manual started/month, auto actuation/cycle	
13.	Relief valves -	four 1-inch relief valve, RV-72A-D 35 gpm at 158 psig, one 1-inch relief valve, and RV-40 35 gpm at 180 psig	

Table A.1.c
Vessel Head Spray (RHR)

1.	Number of lines –	1		
2.	Line size –	6"		
3.	Valve number –	——	32	33
4.	Valve location –	in	in	out
5.	Valve type –	check	MO	MO
6.	Valve operator –	——	ac	dc
7.	Valve normal position –	C	C	C
8.	Power failure position –	——	C	C
9.	Isolation signals –	low vessel level or high drywell pressure or high vessel pressure		
10.	Normal flow direction –	in	in	in
11.	Surveillance requirement –	stroked/shutdown longer than 48 hours, auto isolation/cycle, LLRT/cycle		
12.	Pump surveillance requirement –	flow tested/3 months, manual start/month, auto actuation/cycle		
13.	Relief valves –	RV-35A,B 50 gpm at 425 psig, RV-44 50 gpm at 400 psig (Loop A only), and two 3" relief valves		

Table A.1.d
Core Spray Injection Lines

1.	Number of lines -	2		
2.	Line size -	12"		
3.	Valve number -	13A,B	12A,B***	11A,B***
4.	Valve location -	I	O	O
5.	Valve type -	AO check	MO Gate	MO Gate
6.	Valve operator -	air	ac	ac
7.	Valve normal position -	C	C	O
8.	Power failure position -	——	C	O
9.	Isolation signals -	——	*	*
10.	Normal flow direction -	in	in	in
11.	Surveillance requirement -	+	**	**
12.	Pump surveillance requirement -	auto actuation test every operating cycle, flow test/3 month, manual start/month		
13.	Relief valves -	RV-20A,B 120 gpm at 435 psig		

*Can be opened only if reactor pressure is low or the other valve is closed.
**Operability test/month, LLRT cycle, operational hydro test/cycle (12A, B only).
***Valves interlocked.
+Cycle/month, operational hydrostatic test/cycle.

Table A.1.f
RCIC Suction

1.	Number of lines -	1		
2.	Line size -	6"		
3.	Valve number -	22	21	20*
4.	Valve location -	0	0	0
5.	Valve type -	AO check	MO	MO
6.	Valve operator -	air	dc	dc
7.	Valve normal position -	C	C	0
8.	Power failure position -	----	C	0
9.	Isolation signals -	----	none	none
10.	Normal flow direction -	in	in	in
11.	Surveillance requirement -	+	**	***
12.	Pump surveillance requirement -	manual start every month, flow test/3 months auto actuation test at refueling		
13.	Relief valves -	one 1-inch relief valve		

*There are valves No.20 in HPCI and RCIC.
**Stroked/month, operational hydro test/cycle.
***Stroked/month.
+Stroked every shutdown greater than 48 hours.

Table 1.g___ Screening of Lines Penetrating Contain[...] for Interfacing Lines at Peach Bottom

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PRINCIPAL PENETRATIONS OF THE PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

					Inner Isolation Valves Per Line (Inboard of Primary Containment Shell)			Outer Isolation Valves Per Line (Outboard of Primary Containment Shell)			
	Type of Service	Primary Containment Penetration	Number of Lines	Pipe Size (Inches)	Number	Valve Type	Normal Status	Number	Valve Type	Normal Status	Remarks and Exceptions
A	Main Steam Line	N-7	4	26	1	AO Globe	Open	1	AO Globe	Open	
A	Main Steam Line Drain	N-8	1	3	1	MO Globe	Open	1	MO Globe	Open	
B	Main Steam Sample	N-57	1	1	1	AO Globe	Closed	1	AO Globe	Closed	
C	Feedwater	N-9	2	24	1	Check	Open	1	Check	Open	
B	Feedwater Flush Return	N-9	2	12	-	--	-	1	MO Gate	Closed	
B	Reactor Water Sample	N-41	1	1	1	AO Globe	Closed	1	AO Globe	Closed	
C	Control Rod Hydraulic Return										Deleted from design.
B	Control Rod Drive Withdraw	N-38	185	1	-	--	-	see note 1			
B	Control Rod Drive Insert	N-37	185	1	-	--	-	see note 1			
C	RHR Reactor Shutdown Cooling Supply	N-12	1	20	1	MO Gate	Closed	1	MO Gate	Closed	
E	RHR to Suppression Spray Header*	N-211	2	10	-	--	-	2	MO Globe	Closed	Second valve is MO gate.
E	RHR Containment Spray-Drywell	N-39	2	16	-	--	-	2	MO Gate	Closed	
C	RHR Reactor Head Spray	N-17	1	6	1	MO Gate	Closed	1	MO Gate	Closed	
E	RHR Test Line to Suppression Pool*	N-210	2	18	-	--	-	2	MO Globe	Closed	Second valve is MO gate.
C	RHR LPCI/Shutdown Cooling to Reactor	N-13	2	24	1	AO Check	Closed	2	MO Gate	Closed	Inner valve is testable check, second outer valve is normally open MO globe
E	RHR Pump Suction*	N-226	4	24	-	--	-	1	MO Gate	Open	
B	Standby Liquid Control	N-42	1	1½	1	Check	Closed	1	Check	Closed	
A	Reactor Water Cleanup Outlet	N-14	1	6	1	MO Gate	Open	1	MO Gate	Open	
A	Reactor Water Cleanup Inlet	N-9	1	4	-	--	-	2	Check	Open	Second valve is MO gate.
A	RCIC Turbine Steam Supply	N-10	1	3	1	MO Gate	Open	1	MO Gate	Open	
E	RCIC Turbine Exhaust*	N-212	1	12	-	--	-	2	StopCheck	Closed	Stop check is normally free to open on forward flow, second valve is swing check.
E	RCIC Pump Suction From Suppression Pool*	N-225	1	6	-	--	-	2	MO Gate	Closed	
C	Core Spray to Reactor	N-16	2	12	1	AO Check	Closed	2	MO Gate	Closed	Second outer valve is normally open.
E	Core Spray Test to Suppression Pool*	N-224,N-234	2	10	-	--	-	1	MO Globe	Closed	
E	Core Spray Pump Suction*	N-228	4	16	-	--	-	1	MO Gate	Open	
E	Torus Water Cleanup Pump Suction*	N-225	1	4	-	--	-	2	MO Gate	Open	
E	Torus Make-up*	N-224,N-234	2	2	-	--	-	2	AO Globe	Open	
E	Drywell Equipment Drain	N-19	1	3	-	--	-	2	AO Gate	Closed	
E	Drywell Floor Drain	N-18	1	3	-	--	-	2	AO Gate	Closed	
A	HPCI Turbine Steam Supply	N-11	1	10	1	MO Gate	Open	1	MO Gate	Open	
E	HPCI Turbine Exhaust*	N-214	1	24	-	--	-	2	StopCheck	Closed	Stop check is normally free to open on forward flow, second valve is swing check.
E	HPCI Pump Suction*	N-227	1	16	-	--	-	2	MO Gate	Closed	
B	Traversing In-core Probe	N-35	5	3/8	-	--	-	1	SO Ball	Closed	
B	Traversing In-core Probe Purge	N-35	1	3/8	-	--	-	1	Check	Closed	
B	Instrument Sensing Line	Typical	-	1	-	--	-	2	Flow Check	Open	Second valve is hand globe. Typical of all instrument lines communicating with reactor coolant.
E	Instrument Sensing Line	Typical	-	1	-	--	-	1	Hand Globe	Open	Typical of all instrument lines communicating with primary containment air space or suppression pool.
E	Instrument Air to Drywell	N-22	1	1	-	--	-	2	Check	Closed	Second valve is normally open AO globe.
E	Instrument Air to Suppression Chamber*	N-218A	1	1	-	--	-	2	Check	Closed	Second valve is normally open AO globe.
E	Chilled Water Inlet	N-53,N-54	2	8	-	--	-	1	MO Gate	Open	
E	Chilled Water Outlet	N-55,N-56	2	8	-	--	-	1	MO Gate	Open	
E	Cooling Water Inlet	N-23	1	4	-	--	-	1	MO Gate	Open	
E	Cooling Water Outlet	N-24	1	4	-	--	-	1	MO Gate	Open	
E	Drywell N_2 Purge Inlet	N-25	1	18	-	--	-	2	AO Butterfly	Closed	
E	Drywell Air Purge Inlet	N-25	1	18	-	--	-	2	AO Butterfly	Closed	
E	Drywell N_2 Make-up	N-25	1	1	-	--	-	2	Check	Closed	Second valve is normally open AO globe.

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Table A.1.g (Continued)

Type of Service	Primary Containment Penetration	Number of Lines	Pipe Size (Inches)	Inner Isolation Valves Per Line (Inboard of Primary Containment Shell) Number	Valve Type	Number Status	Outer Isolation Valves Per Line (Outboard of Primary Containment Shell) Number	Valve Type	Normal Status	Remarks and Exceptions
E Drywell Purge Outlet	N-26	1	18	-	--	-	2	AO Butterfly	Closed	
E Drywell Purge Outlet Bypass	N-26	1	2	-	--	-	2	AO Globe	Closed	
E Drywell O_2 Analyzer	N-51	4	1	-	--	-	2	Hand Globe	Open	Second valve is SO globe.
E Suppression Chamber N_2 Purge Inlet*	N-205B	1	20	-	--	-	2	AO Butterfly	Closed	
E Suppression Chamber Air Purge Inlet*	N-205B	1	18	-	--	-	2	AO Butterfly	Closed	
E Suppression Chamber N_2 Make-up*	N-205B	1	1	-	--	-	2	Check	Closed	Second valve is normally open AO glob-
E Suppression Chamber Purge Outlet*	N-219	1	18	-	--	-	2	AO Butterfly	Closed	
E Suppression Chamber Purge Outlet Bypass*	N-219	1	2	-	--	-	2	AO Globe	Closed	
E Suppression Chamber O_2 Analyzer*	N-218b,N-203	2	1	-	--	-	2	Hand Globe	Open	Second valve is SO globe.
E Suppression Chamber Vacuum Breaker*	N-205	2	20	-	--	-	1	Check	Open	

E Personnel and Equipment Openings:

Drywell Head - 1
Equipment Hatch - 1
Equipment Hatch with Personnel Access Lock - 1
Suppression Chamber Access Hatch - 2
Drive Removal Hatch - 1
Construction Manway - 1
Head Access - 1

NOTES: 1. Control rod hydraulic lines can be isolated by the solenoid valves outside the primary containment. Lines that extend outside the primary containment are of small size and terminate in a system designed to prevent out-leakage. Solenoid valves are normally closed but open on rod movement and during reactor scram.
2. * Denotes suppression chamber penetrations.

Footnotes: *Considered

A - High energy line.
B - Small line ≤ 1-1/2".
C - Small ≤ 3" and frequency of LOCA judged to be small.
D - Failure of PIVs does not result in LOCA, frequency of LOCA judged to be small.
E - Not connected to RCS.

A.2 Interfacing Lines at Nine Mile Point 2

The interfacing lines identified for Nine Mile Point 2 are the following:

a. LPCI Injection Lines
b. Shutdown Cooling Suction Line
c. Reactor Pressure Vessel Head Spray
d. Low Pressure Core Spray Injection Line
e. HPCS Pump Suction
f. RCIC Pump Suction
g. Shutdown Cooling Return to Recirculation
h. Steam Condensing Supply Line to RHR Heat Exchanger

These interfacing lines are shown in Figures A.2.a-A.2.h. Tables A.2.a-A.2.h list some data collected for them. Table A.2.i lists the lines penetrating the containment. The single character code in the first column of the table denotes the disposition of the line. An asterisk denotes that the line is considered in the study. A letter means that the line is not further considered, based on the screening criteria denoted by the same letter in Section 2.1.

A.2.1 LPCI Injection Lines

The RHR system consists of three loops. Each loop consists of one RHR pump and the associated valves and pipes. Loop C is used only in the LPCI mode. Loop A and B are also used in other modes, e.g., shutdown cooling mode, steam condensing mode, and containment spray mode. They are identical and independent except the following:

a. Suction line from the recirculation line is shared.
b. Only loop B has a vessel head spray line.
c. Only loop B has a service water connection.
d. Loop C can not be used for fuel pool cooling.
e. The steam line from the RCIC system is shared.

A.2.1.1 Automatic and Manual Control

The LPCI mode of RHR system is actuated automatically on high drywell pressure and low vessel level. The three RHR pumps will start automatically and the injection valves F042A, B, and C will open when the pressure difference across them is $\leq$ 130 psid. The suction valves from the suppression pool are are normally key locked open. To ensure proper system lineup, the following normally closed valves are signaled to close.

a. MO F026A, B and AO F065A, B in RHR heat exchanger discharge to RCIC suction.
b. MO F011A and B in RHR heat exchanger flush to suppression pool.
c. RHR heat exchanger steam pressure reducing valves AO F051A and B.
d. RHR heat exchanger steam inlet isolation valves MO F052A and B and F087A and B.
e. MO F024A, B and F021 in test return line to the suppression pool.
f. Containment spray to suppression pool valves MO F027A and B.
g. Steam condensing mode drain line valves F106A and B, and F107A and B.
h. RHR sample valves F060A and B, and F025A and B.

The LPCI pump motors and injection valves have manual override control that permit the operator to manually control the system subsequent to automatic initiation.

A.2.1.2 Indications of Overpressurization or Interfacing LOCA

In the case that the isolation valves F041 and F042 fail to isolate, the low pressure piping that will be overpressurized is bounded by valves F042, F021, F053, F063, F025, F016, F027, F023, F086, F024, F049, F089B, F060, F065, F031, F080, F055, F087, F051, F072, F085, and F074, thermal relief valve on heat exchanger vessel. Valve F089B applies only to RHR pump B. For RHR pump C which does not have a heat exchanger the low pressure piping that will be overpressurized is bounded by valves F042, F063, F025, F021, F085, and F031. The design pressure of this section is 500 psig. There are two relief valves in this pipe section. Their combined capacity is approximately 185 gpm. Indications of overpressurization or interfacing LOCA are the following:

1. RHR pump discharge abnormal pressure alarm in the control room.
2. High RHR pump room sump level alarm in the control room.
3. High RHR pump room ambient temperature alarm in the control room.
4. High reactor building ventilation exhaust radiation alarm in the control room.
5. High RHR heat exchanger equipment room radiation alarm in the control room.

A.2.2 Shutdown Cooling Suction

A.2.2.1 Automatic and Manual Control

The suction valves F009 and F008 have pressure interlock so that a valve can not be opened if the inboard pressure is high. They are used during the shutdown cooling mode. Valves F006A and B further down stream are normally closed and are interlocked so that a valve can be opened only if the corresponding suppression pool suction valve is closed.

A.2.2.2 Indications of Overpressurization or Interfacing LOCA

If isolation valves F008 and F009 fail open, the low pressure piping that will be overpressurized is bounded by valves F008, F007, F005, F006A, and F006B. The design pressure of the section is 220 psig. A relief valve F005 is located in this section. High pressure in this pipe section is alarmed in the control room. If an interfacing LOCA occurs, the following indications will be available, in addition to low vessel level alarm:

1. High shutdown suction pressure alarm in the control room.
2. High RHR pump room sump level alarm in the control room.
3. High RHR room ambient temperature alarm in the the control room. It also sends an isolation signal to the following valves.
   a. RHR shutdown return valves F053A and B.
   b. RHR shutdown return line inboard bypass valve F099A and B.
   c. RHR shutdown suction valves F008 and F009.
   d. RCIC steam supply valves F063 and F064.

e. RCIC steam supply bypass to inboard isolation valves F076.

f. RHR head spray valve F023.

4. High reactor building ventilation exhaust radiation alarm in the control room.

5. High RHR heat exchanger equipment room radiation alarm in the control room.

A.2.3 Reactor Vessel Head Spray

A.2.3.1 Manual and Automatic Control

Vessel head spray is used in the shutdown cooling mode of the RHR system. Isolation valve F023 can be manually controlled. It receives automatic isolation signal on low vessel level, high RPV pressure or high area ambient temperature.

A.2.3.2 Indications of Overpressurization or Interfacing LOCA

If the check valves, upstream of the isolation valve F023, as well as valve F023 fail, the section of low pressure piping that will be overpressurized is the same as that for LPCI line. Therefore, the same indications will be available to the operators. The only difference is that the isolation valve F023 in the head spray line receive automatic isolation signals.

A.2.4 Low Pressure Core Spray Injection Line

A.2.4.1 Automatic and Manual Control

Core spray pump starts automatically on high drywell pressure or low vessel level. A "close" signal is also sent to MOV F012 in the test return line. The injection valve, F005, is normally closed. It can be opened manually or automatically only if the pressure difference across it is $\leq$ 88 psid. The testable check valve, F006, is designed for remote opening with zero differential pressure across the valve seat. It will close on reverse flow even though the test switches may be positioned for open. The suction valve, F001, is normally open and can be operated with a key lock switch in the control room.

A.2.4.2 Indication of Overpressurization or Interfacing LOCA

If isolation valves, F005 and F006 fail open, the section of piping that will be overpressurized is bounded by valves F005, F018, F075, F003, F012, F004, and F034. Its design pressure is 550 psig. A relief valve, F018, is located in this section. The following indications are available to the operators, in addition to high drywell pressure and low vessel level:

1. High core spray pump discharge pressure alarm in the control room. The discharge pipe between the discharge check valve, F003, and the injection valve, F005, is normally filled with water by a line-fill pump that takes suction from the core spray pump suction. High or low pressure is alarmed in the control room.
2. High core spray pump room sump level alarm in the control room.
3. High reactor building ventilation exhaust radiation alarm in the control room.

A.2.5 HPCS Pump Suction

A.2.5.1 Automatic and Manual Control

The HPCS pump starts automatically on low vessel level or high drywell pressure. Upon actuation, the normally open suction valve from the condensate storage tank is signaled to open, the test return valves F010, F011, and F023 are signaled to close, the normally closed injection valve F004 is signaled to open. The suction valve, F015, from the suppression pool is normally closed and will open automatically when the CST level is low or the suppression pool level is high. After valve F015 is fully opened, the suction valve from the CST is closed automatically. The injection valve will close automatically when the vessel level reaches level 8. The water leg pump keeps the pipe section between the discharge check valve and the injection valve filled. Low pump discharge pressure is alarmed in the control room. The HPCS pump discharge check valve is located below the minimum suppression pool level and the pipe section between the pump and the check valve is normally filled with water.

A.2.5.2 Indications of Overpressurization or Interfacing LOCA

If containment isolation valves F004 and F005 fail open, the pipe section that will be pressurized is bounded by valves F004, F003, F010, F023, F024, F006, F035, and F026. This section is high pressure designed. Therefore, no overpressurization occurs, additional valve failures must occur to result in overpressurization. If HPCS discharge valve also fails open, then the low pressure piping on the suction side will be overpressurized. The overpressurization is bounded by valves F002, F016, F019, F035, F014, and the HPCS pump. There is a 10 gpm capacity relief valve in this pipe section that discharges to the suppression pool. If an interfacing LOCA occurs as a result of overpressurization the following indications may be available to the operators, in addition to the low vessel level alarm:

1. High HPCS pump suction pressure alarm in the control room.
2. Low condensate storage tank level alarm in the control room.
3. High HPCS pump room sump water level alarm in the control room.
4. High reactor building ventilation exhaust radiation alarm in the control room.

A.2.6 RCIC Pump Suction

A.2.6.1 Automatic and Manual Control

The RCIC system is actuated automatically on low vessel level. The actuation signal sends an open signal to the injection valve F013, the pump suction valve F010 from the condensate storage tank, and the steam supply valve F045. It also sends a close signal to the normally closed test return valve F022. The steam supply valve F045 is normally closed and can be opened if the turbine exhaust valve F068 is fully open. The injection valve F013 is normally closed and can be opened automatically if the steam supply valve F045 is not fully closed. It can be manually closed with valve F045 closed. The pump suction from condensate storage tank F010 is normally open and will close automatically when the suction valve F031 from the suppression pool is open.

The RCIC system is connected with the RHR system at three locations. In the steam condensing mode of RHR system, steam is taken from the RCIC steam supply line outside the drywell. The condensate from the RHR heat exchangers can be supplied to the RCIC pump suction through normally closed valves F026A and B. The discharge from RHR pump B is connected with the RCIC vessel head spray line outside the drywell.

When the vessel level reaches level 8, the steam supply valve F045 will close automatically, which will cause the injection valve F013 to close. The following isolation signals will close the turbine trip and throttle valve which will cause the injection valve to close.

a. High RCIC pump suction pressure.
b. RHR equipment area high temperature.
c. RCIC pipe routing area high temperature.
d. RCIC equipment area high temperature.
e. Steam supply pressure low.
f. Steam line high differential pressure.
g. Instrument line break.
h. Turbine exhaust diaphragm pressure high.

A.2.6.2 <u>Indications of Overpressurization or Interfacing LOCA</u>

If valves F066, F065, and F013 fail open, the reactor pressure will overpressurize the suction side of the RCIC pump. The overpressurization is bounded by valves F013, F006, F022, F011, F061, F026A, F026B, F030, F057, and F019. The design pressure of the pump suction is 100 psig. Three relief valves F036, F017, and F018 are located in the section. If an interfacing LOCA occurs, the following indications will be available, in addition to the low vessel level alarm:

1. High RCIC pump suction pressure alarm in the control room.
2. High RCIC pump room sump level alarm in the control room.
3. High reactor building ventilation exhaust radiation alarm in the control room.

4. High RCIC room temperature alarm in the control room. It will also isolate the RCIC system by closing the steam supply isolation valves F063, F064, and the turbine trip and throttle valve. After the turbine trip and throttle valve is fully closed, the injection shutoff valve F013 will close automatically.

A.2.7 Shutdown Cooling Return to Recirculation

A.2.7.1 Automatic and Manual Control

The shutdown cooling mode of the RHR system is initiated manually after the reactor pressure is 95 psig or less. This condition can be reached approximately 1-1/2 hours after shutdown with the maximum cooldown rate of 100°F/hr. The suppression pool suction valve is closed. The piping is flushed and prewarmed by opening the bypass valve of the testable check valve and the suction valves from the recirculation line. The RHR pump is then started with the heat exchanger bypass valve open and the heat exchanger valves closed. The service water valves and the heat exchanger valves are opened a few minutes later. Valves F053 and F048 are used to control the cool down rate. The containment isolation valve F053 receives automatic isolation signal on low vessel level, high vessel pressure and high RHR equipment room ambient temperature.

A.2.7.2 Indications of Overpressurization or Interfacing LOCA

If the isolation valves F050 and F053 fail open, the low pressure piping that will be overpressurized is identical to that for a LPCI line (see Figure A.2.a1). The same indications will be available.

A.2.8 RHR Steam Condensing Supply Line

A.2.8.1 Automatic and Manual Control

The steam condensing mode of the RHR system can be manually initiated 1-1/2 hours after a reactor trip. It is capable of condensing all the steam generated. It takes steam from the RCIC steam line outside the drywell and

condenses it in the RHR heat exchangers. The condensate can be returned to the RCIC suction or the suppression pool. The containment isolation valves for this line are normally open. The automatic isolation signals are shown in Table A.2h.

A.2.8.2 Indications of Overpressurization or Interfacing LOCA

If the pressure isolation valves F052 and F051 or F087 fail open, the low pressure piping that will be overpressurized is the same as that for LPCI lines. Therefore, the same indications will be available to the operators. The only difference is that the containment isolation valves F063 and F064 should close upon automatic isolation signals.

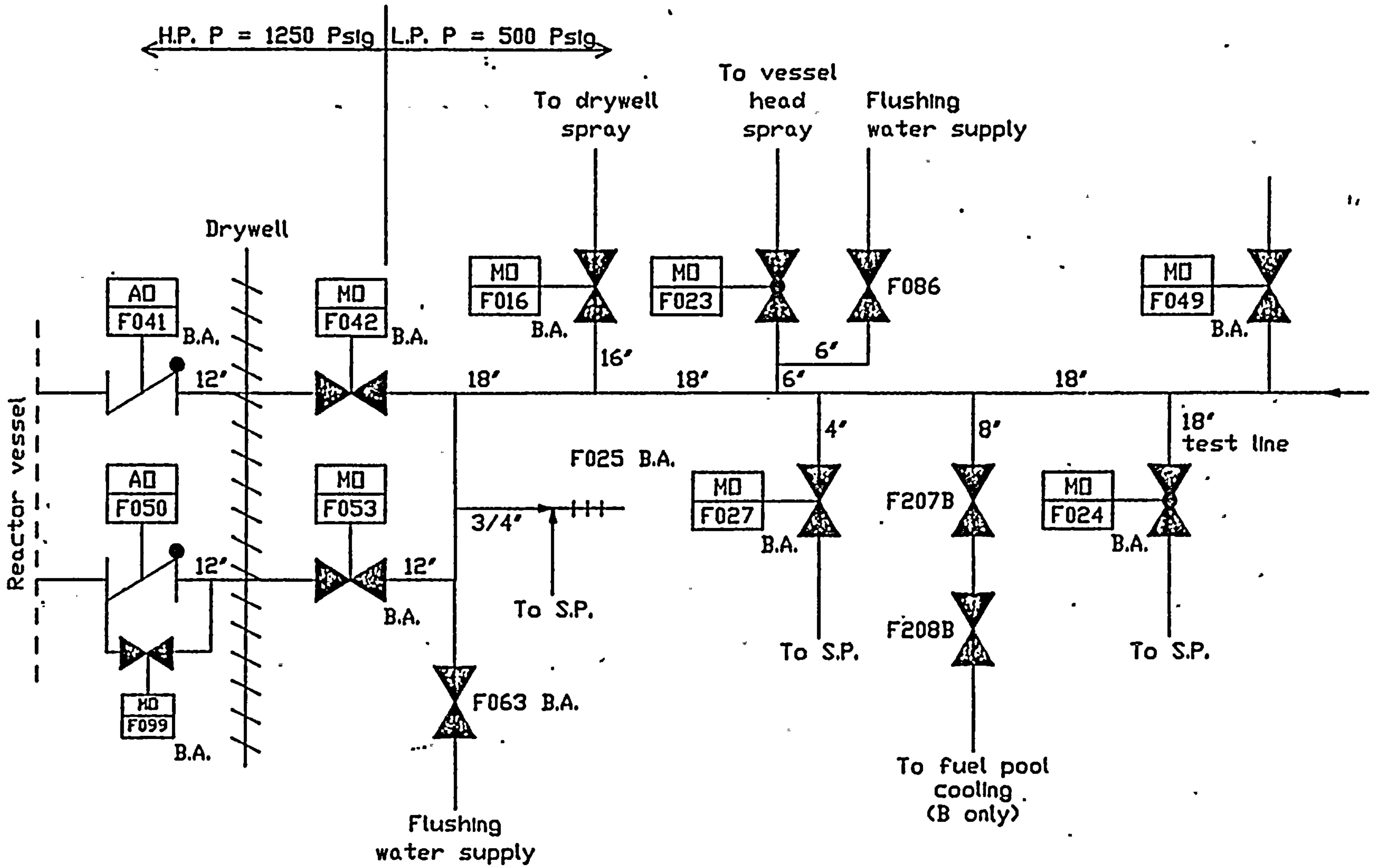

Figure A.2a1 LPCI injection lines for pumps A, B, and shutdown cooling return to recirculation line (sheet 1 of 2).

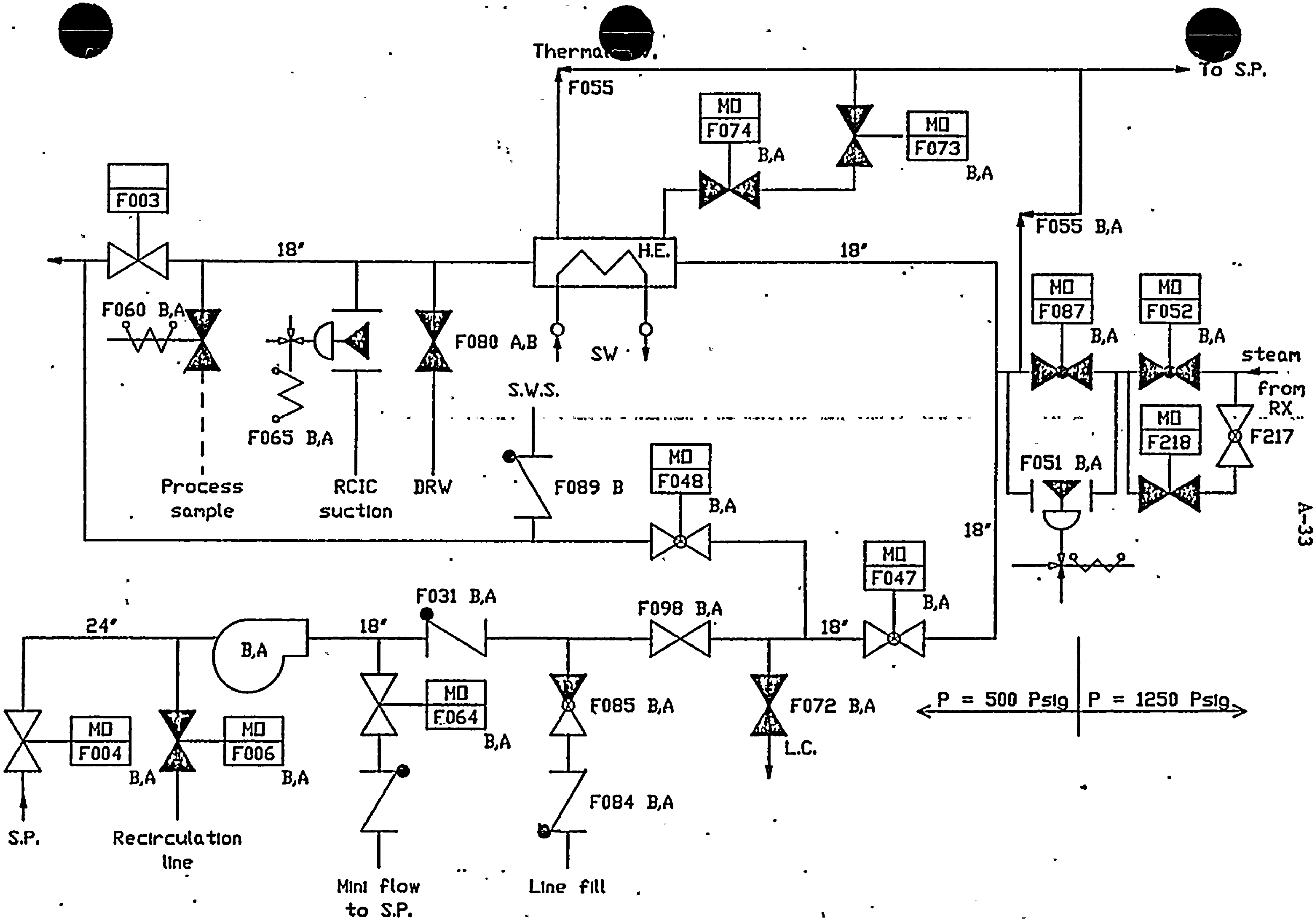

Figure A.2a1 LPCI injection lines for pumps A, B, and shutdown cooling return to recirculation line (sheet 2 of 2).

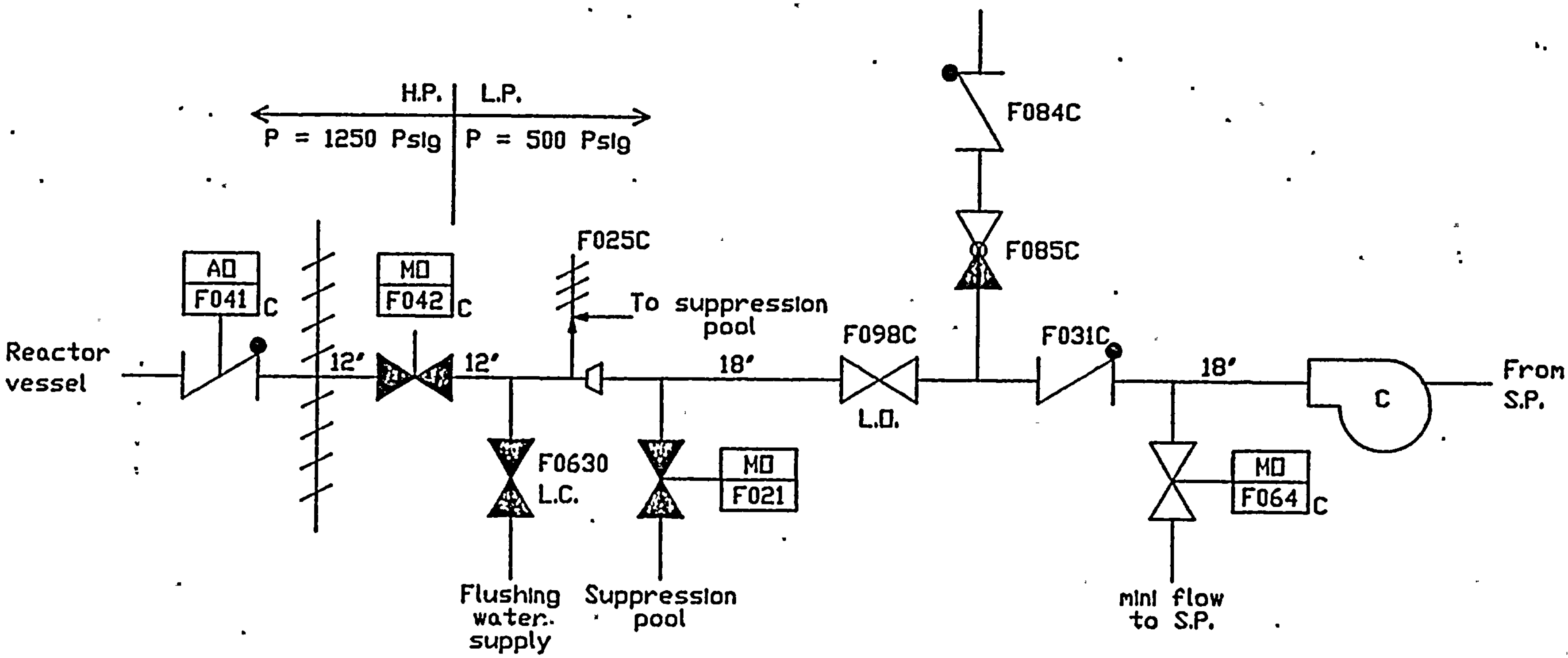

Figure A.2a2 LPCI injection line for pump C.

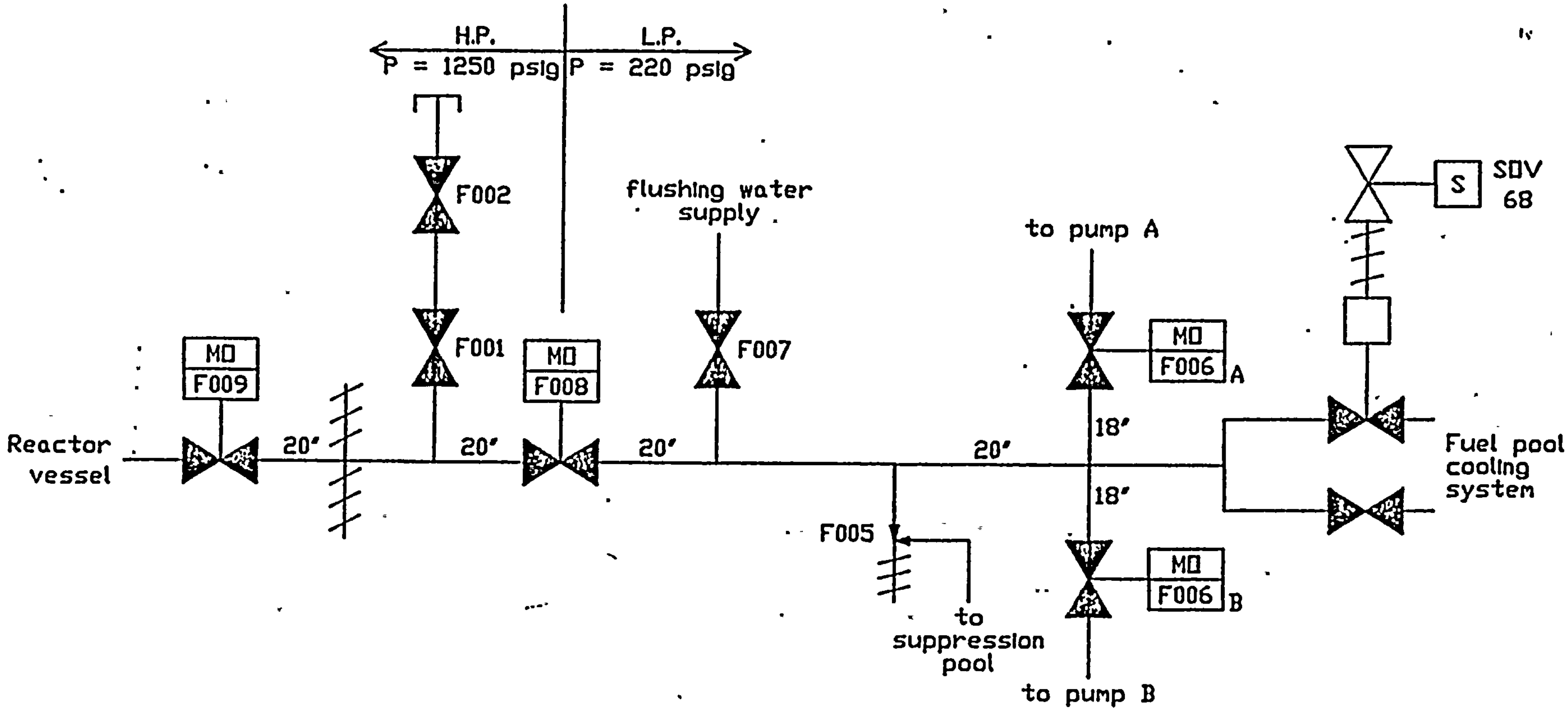

Figure A.2b Shutdown cooling suction.

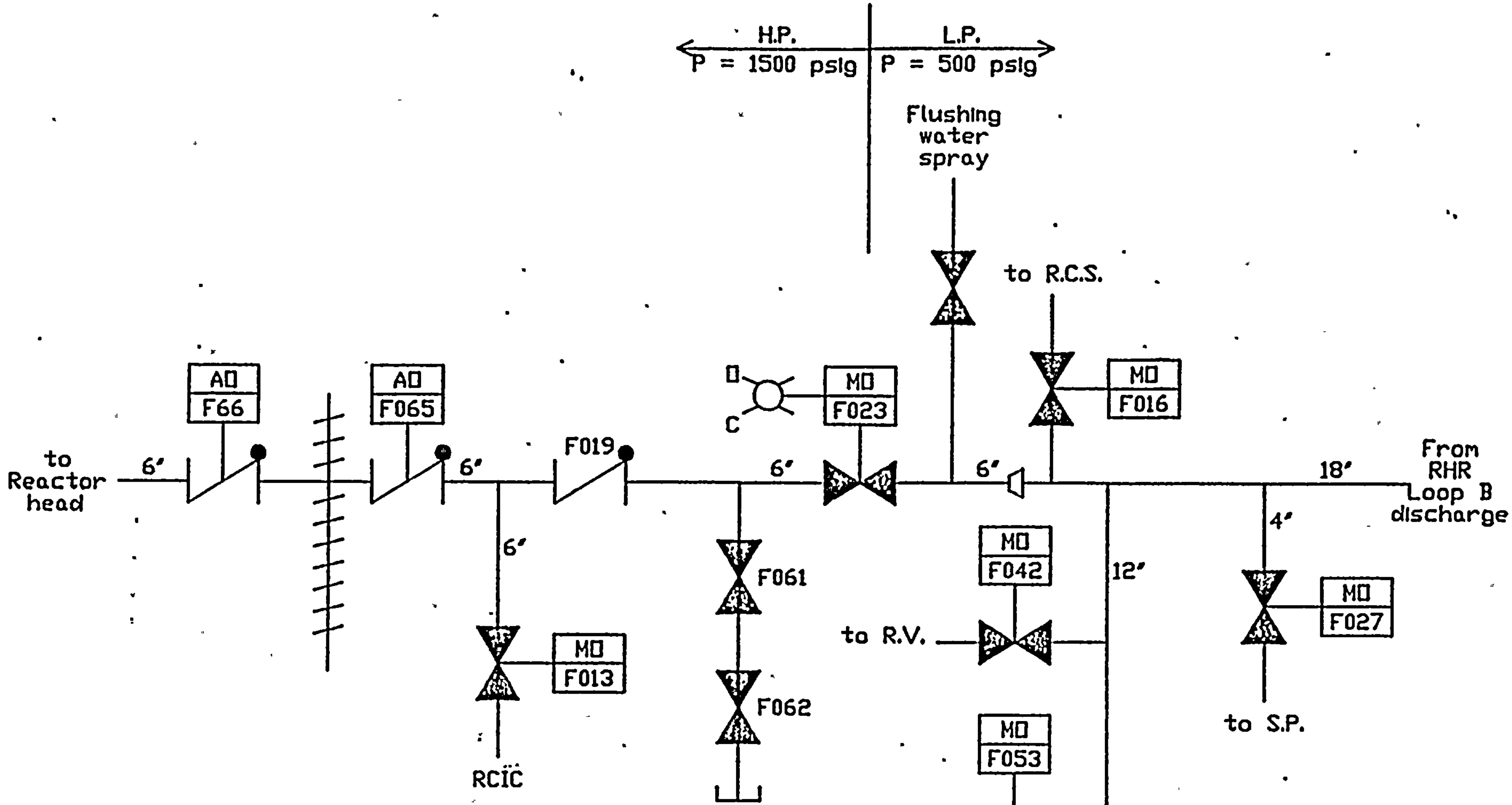

Figure A.2c Reactor vessel head spray line.

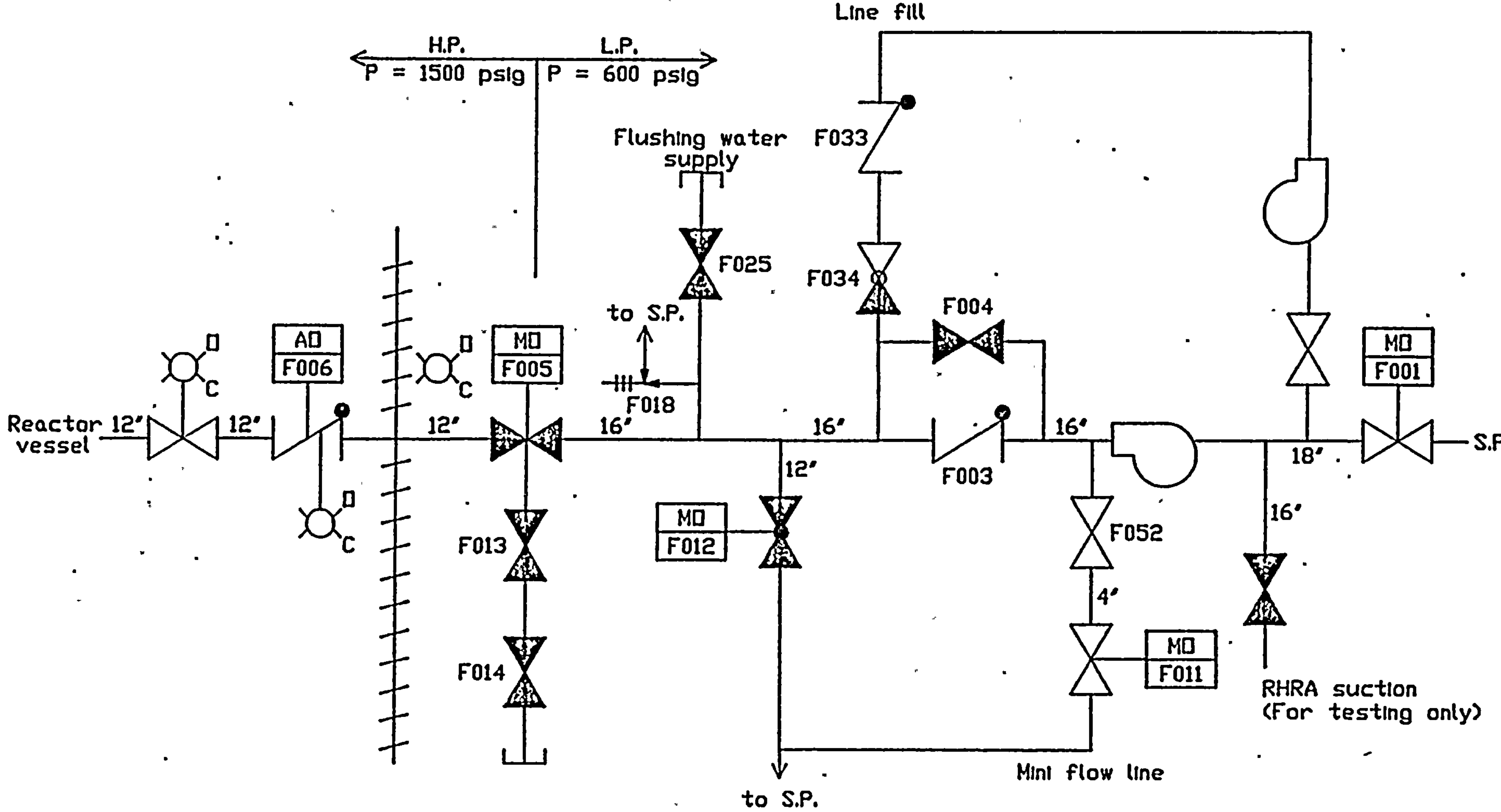

Figure A.2d Low pressure core spray injection line.

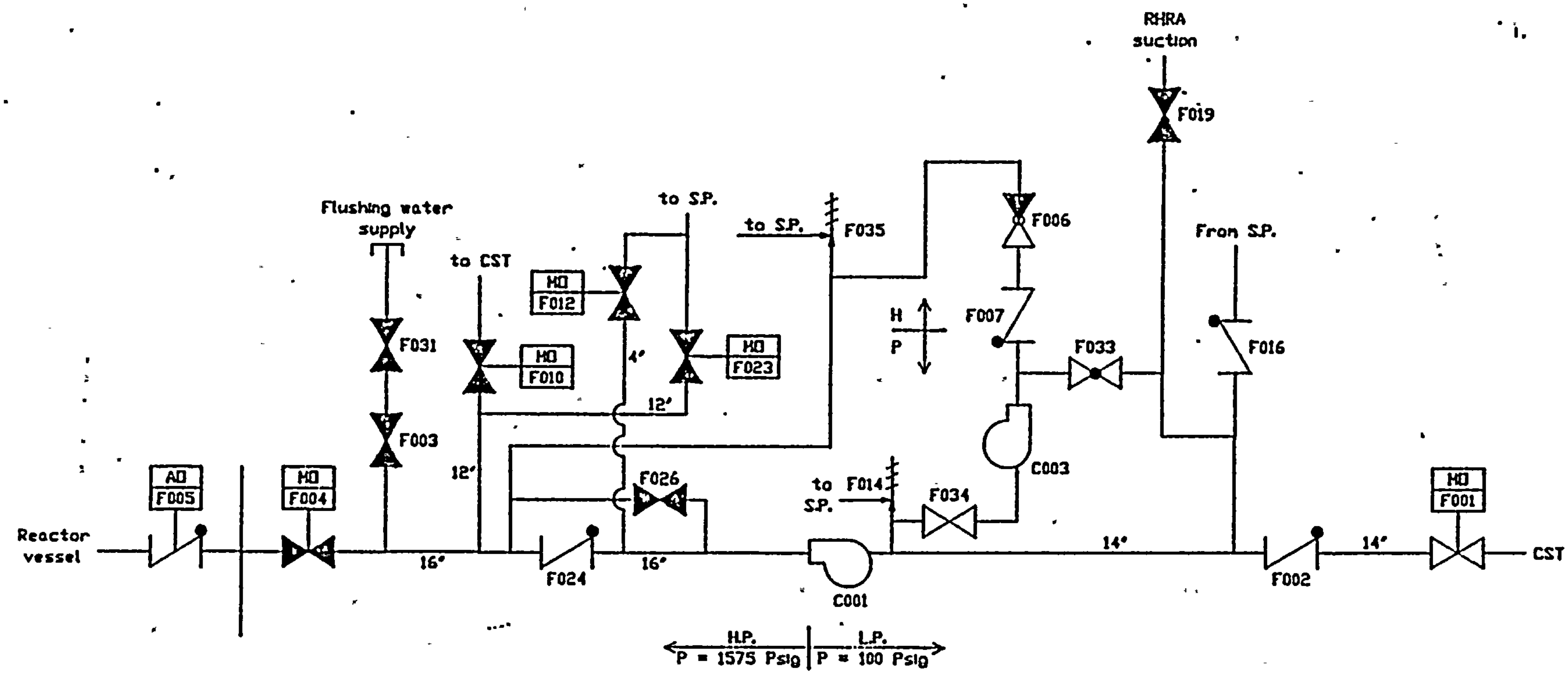

Figure A2e High pressure core spray system.

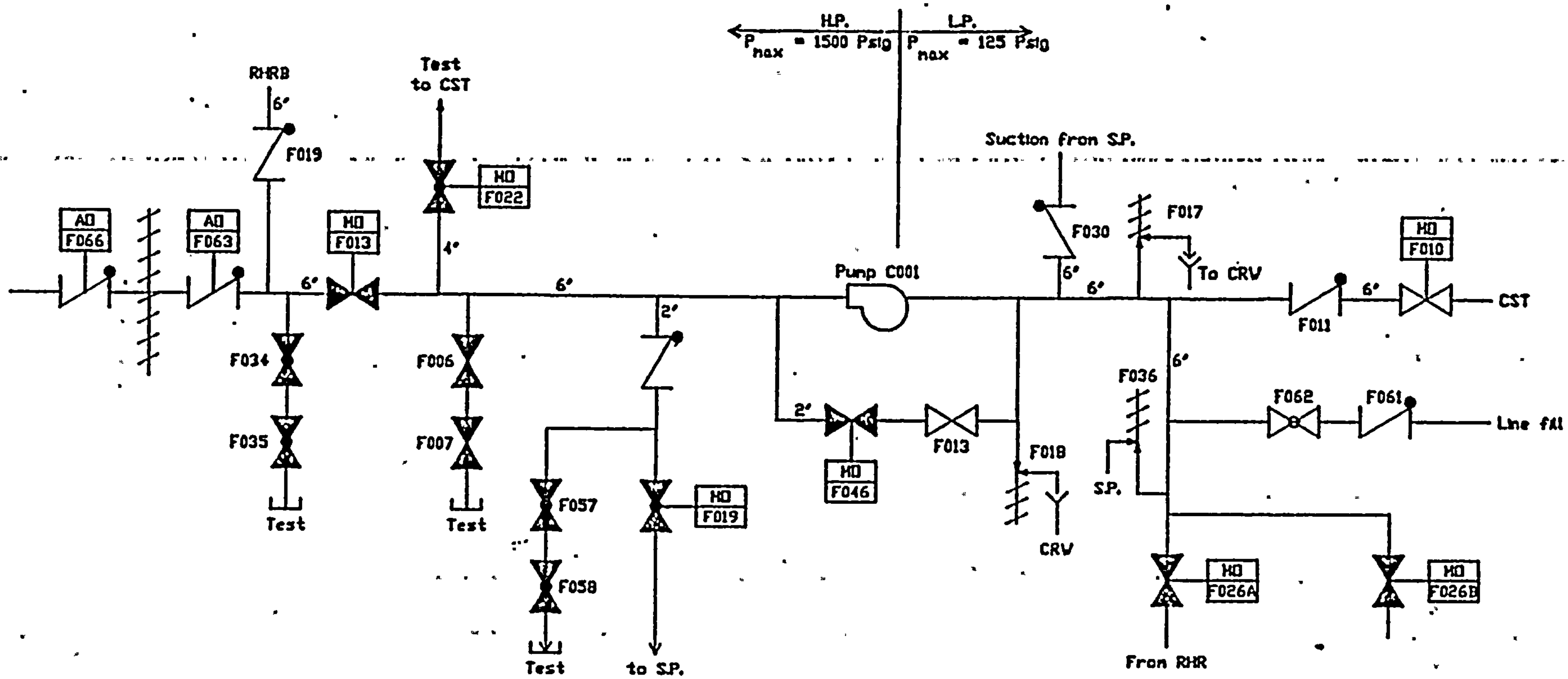

Figure A.2f RCIC pump suction.

Table A.2.a
LPCI Injection Lines

1.	Number of lines -	3	
2.	Line size -	12"	
3.	Valve number -	F041(16)	F042(24)
4.	Valve location -	in	out
5.	Valve type -	AO check	MOV
6.	Valve operator -	(air)	ac
7.	Valve normal position -	C	C
8.	Power failure position -		C
9.	Isolation signals -	None	*
10.	Normal flow direction -	in	in
11.	Surveillance requirement -	**	***
12.	Pump surveillance requirement -	Flow test/3 month, auto actuation/ 18 months	
13.	Relief capacity & setpoint -	F025 10 gpm at 470 psig F055 97000 lb/hr at 500 psig	

*Can be opened only if the pressure difference across the valve is ≤ 130 psid.

**Stroked every cold shutdown if not stroked in 92 days, LLRT/18 months, leak test/18 months and after cycling.

***Stroked every cold shutdown if not stroked in 92 days, position verification/month, auto actuation/18 months, LLRT/18 months, PIV leak test/18 months and after cycling.

Table A.2.b
Shutdown Cooling Suction

1.	Number of lines -	1	
2.	Line size -	20"	
3.	Valve number -	F009(112)	F008(113)
4.	Valve location -	in	out
5.	Valve type -	MOV	MOV
6.	Valve operator -	ac	ac
7.	Valve normal position -	C	C
8.	Power failure position -	C	C
9.	Isolation signals -	*	*
10.	Normal flow direction -	in	in
11.	Surveillance requirement -	**	**
12.	Pump surveillance requirement -	Flow test/3 month, auto actuation/ 18 months	
13.	Relief capacity & setpoint -	F005 1 gpm at 200 psig	

*Low vessel level, high vessel pressure, high area ambient temperature.
**Position verification/month, LLRT/18 months, PIV leak test/18 months, stroke at cold shutdown if not stroked in 92 days.

Table A.2.c
Vessel Head Spray (RCIC)

1.	Number of lines -	1		
2.	Line size -	6"		
3.	Valve number -	F066(157)	F065(156)	F013(126)
4.	Valve location -	in	out	out
5.	Valve type -	Check	Check	MO
6.	Valve operator -	air	air	dc
7.	Valve normal position -	C	C	C
8.	Power failure position -	——	——	C
9.	Isolation signals -	Low RPV level, or high RPV pressure, high area ambient temperature		
10.	Normal flow direction -	in	in	in
11.	Surveillance requirement -	*	*	**
12.	Pump surveillance requirement -	Flow test/3 month, auto actuation/18 months		
13.	Relief capacity & setpoint -	F036 465 gpm at 125 psig F017, F018		

*LLRT/18 months.
**LLRT/18 months, stroke at cold shutdown if not stroked in 92 days, position verification/month, auto actuation/18 months.

Table A.2.d
Low Pressure Core Spray Injection Line

1.	Number of lines -	1	
2.	Line size -	12"	
3.	Valve number -	F006	F005
4.	Valve location -	I	O
5.	Valve type -	AO check	MO gate
6.	Valve operator -	(air)	ac
7.	Valve normal position -	C	C
8.	Power failure position -	-	C
9.	Isolation signals -	None	*
10.	Normal flow direction -	in	in
11.	Surveillance requirement -	***	**
12.	Pump surveillance requirement -	Flow test/3 month, auto actuation/ 18 months	
13.	Relief capacity & setpoint -	F018 100 gpm at 600 psig	

*Can be opened only if pressure differential across the valve is $\leq$ 130 psid.
**Position verification/month, auto actuation/18 months, LLRT/18 months, PIV leak test/18 months stroked at cold shutdown if not stroked in 92 days.
***Stroked at cold shutdown if not stroked in 92, days, LLRT/18 months, PIV leak test/18 months.

Table A.2.e
HPCS Pump Suction

1.	Number of lines -	1	
2.	Line size -	12"	
3.	Valve number -	F005	F004
4.	Valve location -	in	out
5.	Valve type -	AO check	MO gate
6.	Valve operator -	(air)	ac
7.	Valve normal position -	C	C
8.	Power failure position -	-	C
9.	Isolation signals -	None	None
10.	Normal flow direction -	in	in
11.	Surveillance requirement -	**	*
12.	Pump surveillance requirement -	Flow test/3 month, auto actuation/ 18 months at refueling	
13.	Relief capacity & setpoint -	F035 at 1525 psig F014 10 gpm at >100 psig	

*Position verification/month, auto actuation/18 months, LLRT/18 months, PIV leak test/18 months stroked at cold shutdown if not stroked in 92 days.
**LLRT/18 months, PIV leak test/18 months.

Table A.2.f
RCIC Pump Suction

1.	Number of lines –	1		
2.	Line size –	6"		
3.	Valve number –	F066(156)	F065(157)	F013(126)
4.	Valve location –	in	out	out
5.	Valve type –	AO check	AO gate	MO
6.	Valve operator –	(air)	(air)	dc
7.	Valve normal position –	C	C	C
8.	Power failure position –	–	–	C
9.	Isolation signals –	None	None	*
10.	Normal flow direction –	in	in	in
11.	Surveillance requirement –	**	**	***
12.	Pump surveillance requirement –	Flow test/3 month, auto actuation/ 18 months if not tested in past 92 days		
13.	Relief capacity & setpoint –	F036 465 gpm at 125 psig F017, F018		

*It will close automatically if either the turbine steam supply valve or the turbine trip and throttle valve is closed.

**Auto actuation/18 months, LLRT/18 months, PIV leak test/18 months, stroked/cycle at cold shutdown if not tested in past 92 days or refueling.

***Position verification/month, auto actuation/18 months stroked/cycle at cold shutdown if not tested in past 92 days or refueling.

Table A.2.g
Shutdown Cooling Return to Recirculation

1.	Number of lines -	2	
2.	Line size -	12"	
3.	Valve number -	F050(39)	F053(40)
4.	Valve location -	in	out
5.	Valve type -	AO check	MOV
6.	Valve operator -	(air)	ac
7.	Valve normal position -	C	C
8.	Power failure position -	-	C
9.	Isolation signals -	None	*
10.	Normal flow direction -	in	in
11.	Surveillance requirement -	**	***
12.	Pump surveillance requirement -	Flow test/3 month, auto actuation/ 18 months	
13.	Relief capacity & setpoint -	F025 10 gpm at 470 psig F055 97000 lb/hr at 500 psig	

*Low vessel level or high reactor pressure or high area temperature.
**LLRT/18 months, PIV leak test/18 months strok/cold shutdown, 92 days.
***LLRT/18 months, PIV leak test/18 months, strok/cold shutdown if not tested in 92 days, position verification/month.

Table A.2.h
RHR Steam Condensing Supply Line

1.	Number of lines -	1						
2.	Line size -	8"						
3.	Valve number -	F087(23)	F052(23)	F218(80)	F051(21)	F063	F064	F076
4.	Valve location -	out	out	out	out	in	out	in
5.	Valve type -	Globe	Globe	Globe	Diaph.	Gate	Gate	Globe
6.	Valve operator -	ac	ac	ac	air	ac	ac	ac
7.	Valve normal position -	C	C	C	C	O	O	C
8.	Power failure position -	C	C	C	C	O	O	O
9.	Isolation signals -					*	*	*
10.	Normal flow direction -	out	out	out	out	out	out	out
11.	Surveillance requirement -	**	**	****	**	***	***	***
12.	Pump surveillance requirement -	Flow test/month, auto actuation/18 months						
13.	Relief capacity & setpoint -	F025 10 gpm at 470 psig F055 97000 lb/hr at 500 psig						

*High RCIC pipe routing or equipment area ambient temperature, low RCIC steam supply pressure, high steam line differential pressure, high RCIC turbine exhaust diaphragm pressure, high RHR equipment area temperature.

**PIV leak test/18 months after maintenance, after cycling.

***LLRT/18 months.

****PIV leak test/18 months, after maintenance, after cycling, stroke/3 months at power.

Table A.2.1
Screening of Lines Penetrating Containment for Interfacing Lines at Nine Mile Point-2

CONTAINMENT ISOLATION PROVISIONS FOR FLUID LINES

	Penetration No.	System Identification	GDC or Reg. Guide	ESF System	Fluid	Size (in.)	FSAR Arrangement Figure	Location of Valve Inside/Outside Primary Containment	Length of Pipe - Containment to Outside Isolation Valve	Type Test	Potential Bypass Leakage Path	Valve Number	Valve Number	Type	Operator	Actuator Mode Primary	Actuator Mode Secondary	Position Normal	Position Shutdown	Position Post-Accident	Position Power Failure	Isolation Signal	Closure Time	Power Source	Notes
A	[illegible]	Main steam line A	55	No	Steam	26	6.2-70 Sh. 1	Inside Outside	5'-2"	C C	Yes	[illegible] [illegible]	[illegible] [illegible]	Ball Ball	[illegible] [illegible]	Hydraulic to open; spring to close	N/A	Open	Closed	Closed	Closed	[illegible]	3 to 5 sec	N/A	[illegible]
B		Main steam line A drain line				2 3/4		Outside Outside	36'-0" [illegible]	C		[illegible] [illegible]	– [illegible]	Globe Globe	[illegible] [illegible]	Elec. Elec.	Manual N/A	Closed Closed	Closed Closed	Closed Closed	[illegible] Closed	[illegible]	[illegible] N/A	[illegible] N/A	
A	[illegible]	Main steam line B	55	No	Steam	26	6.2-70 Sh. 1	Inside Outside	5'-2"	C C	Yes	[illegible] [illegible]	[illegible] [illegible]	Ball Ball	[illegible] [illegible]	Hydraulic to open; spring to close	N/A	Open	Closed	Closed	Closed	[illegible]	3 to 5 sec	N/A N/A	[illegible]
B		Main steam line B drain line				2 3/4		Outside Outside	36'-0" [illegible]	C		[illegible] [illegible]	– [illegible]	Globe Globe	[illegible] [illegible]	Elec. Elec.	Manual N/A	Closed Closed	Closed Closed	Closed Closed	[illegible] Closed	[illegible]	[illegible] N/A	[illegible] N/A	
A	[illegible]	Main steam line C	55	No	Steam	26	6.2-70 Sh. 1	Inside Outside	5'-2"	C C	Yes	[illegible] [illegible]	[illegible] [illegible]	Ball Ball	[illegible] [illegible]	Hydraulic to open; spring to close	N/A	Open	Closed	Closed	Closed	[illegible]	3 to 5 sec	N/A	[illegible]
B		Main steam line C drain line				2 3/4		Outside Outside	36'-0" [illegible]	C		[illegible] [illegible]	– [illegible]	Globe Globe	[illegible] [illegible]	Elec. Elec.	Manual N/A	Closed Closed	Closed Closed	Closed Closed	[illegible] Closed	[illegible]	[illegible] N/A	[illegible] N/A	
A	[illegible]	Main steam line D	55	No	Steam	26	6.2-70 Sh. 1	Inside Outside	5'-2"	C C	Yes	[illegible] [illegible]	[illegible] [illegible]	Ball Ball	[illegible] [illegible]	Hydraulic to open; spring to close	N/A	Open	Closed	Closed	Closed	[illegible]	3 to 5 sec	N/A	[illegible]
B		Main steam line D drain line				2 3/4		Outside Outside	36'-0" [illegible]	C		[illegible] [illegible]	– [illegible]	Globe Globe	[illegible] [illegible]	Elec. Elec.	Manual N/A	Closed Closed	Closed Closed	Closed Closed	[illegible] Closed	[illegible]	[illegible] N/A	[illegible] N/A	
A	[illegible]	Main steam drain line	55	No	Steam	6	6.2-70 Sh. 2	Inside Outside	[illegible]	C C	Yes	[illegible] [illegible]	[illegible] [illegible]	Globe Globe	[illegible] [illegible]	Elec. Elec.	Manual Manual	Closed Closed	Closed Closed	Closed Closed	[illegible] [illegible]	[illegible]	[illegible]	[illegible]	
	[illegible]	Spare								[illegible]															

Table A.2.1 (Continued)

	Penetration No.	System Description	GDC or Reg. Guide	ESF System	Fluid	Line Size (in)	FSAR Arrangement Figure	Location of Valve Inside/Outside Primary Containment	Length of Pipe - Containment to Outside Isolation Valve	Type Test	Potential Bypass Leakage Path	Valve Number (MPL)	Valve Number (GE)	Valve Type	Operator	Actuation Mode Primary	Actuation Mode Secondary	Normal Position	Shutdown Position	Post-Accident Position	Power Failure Position	Isolation Signal	Closure Time	Power Source	Notes
*	Z-4A	Feedwater line A to RPV	55	No	Water	24	6.2-70 Sh. 3	Outside	[illegible]	C	Yes	[illegible]	[illegible]	Swing Check	AOT	Process	Spring (test only)	Open	Closed	Closed	N/A	Reverse flow	The line is taken for one valve volume to pass through the valve	N/A	11,32
								Inside		C		[illegible]	[illegible]	Swing Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow			
								Outside	[illegible]	C		[illegible]	[illegible]	Gate	MOT	Elec.	Manual	Open	Closed	Closed	FAI	[illegible]	N/A	Div I	
					Water	8	6.2-70 Sh. 3	Outside	[illegible]	C		[illegible]	[illegible]	Globe	MOT	Elec.	Manual	Open	Open	Closed	FAI	[illegible]	N/A	Div I	
*	Z-4B	Feedwater line B to RPV	55	No	Water	24	6.2-70 Sh. 3	Inside		C	Yes	[illegible]	[illegible]	Swing Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow	The line is taken for one valve volume to pass through the valve	N/A	11,32
								Outside	[illegible]	C		[illegible]	[illegible]	Swing Check	AOT	Process	Spring (test only)	Open	Closed	Closed	N/A	Reverse flow			
								Outside	[illegible]	C		[illegible]	[illegible]	Gate	MOT	Elec.	Manual	Open	Closed	Closed	FAI	[illegible]	N/A	Div II	
					Water	8	6.2-70 Sh. 3	Outside	[illegible]	C		[illegible]	[illegible]	Globe	MOT	Elec.	Manual	Open	Open	Closed	FAI	[illegible]	N/A	Div I	
E	Z-5A	RHS Pump A suction from suppression pool	56	Yes	Water	24	6.2-70 Sh. 4	Outside	[illegible]	C	No	[illegible]	[illegible]	Tricentric butterfly	MOT	Elec.	Manual	Open	Closed	Open	FAI	[illegible]	[illegible]	Div I	[illegible]
E	Z-5B	RHS Pump B suction from suppression pool	56	Yes	Water	24	6.2-70 Sh. 4	Outside	[illegible]	C	No	[illegible]	[illegible]	Tricentric butterfly	MOT	Elec.	Manual	Open	Closed	Open	FAI	[illegible]	[illegible]	Div II	[illegible]
E	Z-5C	RHS Pump C suction from suppression pool	56	Yes	Water	24	6.2-70 Sh. 4	Outside	[illegible]	C	No	[illegible]	[illegible]	Tricentric butterfly	MOT	Elec.	Manual	Open	Closed	Open	FAI	[illegible]	[illegible]	Div II	[illegible]
E	Z-6A	RHS test line loop B to suppression pool	56	Yes	Water	18	6.2-70 Sh. 4	Outside	[illegible]	C	No	[illegible]	[illegible]	Tricentric butterfly	MOT	Elec.	Manual	Open	Closed	Open	FAI	[illegible]	[illegible]	Div I	[illegible]

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Table A.2.1 (Continued)

	Penetration No.	System Designation	GDC or Reg. Guide	ESF System	Fluid	Size (in.)	FSAR Arrangement Figure	Location of Valve Inside/Outside Primary Containment	Length of Pipe - Containment to Outside Isolation Valve	Type Test	Potential Bypass Leakage Path	Valve Number	Valve Number	Valve Type	Operator	Actuation Mode Primary	Actuation Mode Secondary	Position Normal	Position Shutdown	Position Post-Accident	Position Power Failure	Isolation Signal	Closure Time (sec)	Power Source	Notes
E	[illegible]	RHS test line loop A to suppression pool	56	Yes	Water	18	6.2-70 Sh. 6	Outside	10'-6"	C	No	[illegible]	[illegible]	Tricentric Butterfly	MOV	Elec.	Manual	Open	Closed	Open	FAI	[illegible]	45	Div II	15
E	[illegible]	RHS containment spray loop A to suppression pool	56	Yes	Water	[illegible]	6.2-70 Sh. 7	Outside	10'-3"	C	No	[illegible]	[illegible]	Globe	MOV	Elec.	Manual	Closed	Closed	Open	FAI	[illegible]	15	Div I	10,15
E	[illegible]	RHS containment spray loop B to suppression pool	56	Yes	Water	[illegible]	6.2-70 Sh. 7	Outside	[illegible]	C	No	[illegible]	[illegible]	Globe	MOV	Elec.	Manual	Closed	Closed	Open	FAI	[illegible]	15	Div II	10,15
E	[illegible]	RHS containment spray loop A to drywell	56	Yes	Water	14	6.2-70 Sh. 8	Outside Outside	2'-0" 11'-3"	C C	No	[illegible]	[illegible]	Gate Gate	MOV MOV	Elec. Elec.	Manual Manual	Closed Closed	Closed Closed	Open Open	FAI FAI	[illegible]	[illegible]	Div I Div I	10,15
E	[illegible]	RHS containment spray loop B to drywell	56	Yes	Water	16	6.2-70 Sh. 8	Outside Outside	2'-0" 9'-6"	C C	No	[illegible]	[illegible]	Gate Gate	MOV MOV	Elec. Elec.	Manual Manual	Closed Closed	Closed Closed	Open Open	FAI FAI	[illegible]	[illegible]	Div II Div II	[illegible],15
*	[illegible]	RHS/LPCI Loop A to RPV	55	Yes	Water	12	6.2-70 Sh. 9	Outside Inside	[illegible]	C C	No	[illegible]	[illegible]	Gate Check	MOV AOV	Elec. Process	Manual Air (Test only)	Closed Closed	Closed Closed	Open Open	FAI Closed flow	[illegible] Reverse flow	[illegible] N/A	Div I Div I	11,13,15
*	[illegible]	RHS/LPCI Loop B to RPV	55	Yes	Water	12	6.2-70 Sh. 9	Outside Inside	[illegible]	C C	No	[illegible]	[illegible]	Gate Check	MOV AOV	Elec. Process	Manual Air (Test only)	Closed Closed	Closed Closed	Open Open	FAI Closed	[illegible] Reverse flow	[illegible] N/A	Div II Div II	11,13,15
*	[illegible]	RHS/LPCI Loop C to RPV	55	Yes	Water	12	6.2-70 Sh. 9	Outside Inside	[illegible]	C C	No	[illegible]	[illegible]	Gate Check	MOV AOV	Elec. Process	Manual Air (Test only)	Closed Closed	Closed Closed	Open Open	FAI Closed	[illegible] Reverse flow	[illegible] N/A	Div II Div II	11,13,15

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Table A.2.i (Continued)

[illegible]

[illegible] 6.2-[illegible] (Cont)

	Pen. No.	System Description	[illegible]	ESF System	Fluid	Size (in.)	FSAR Arrangement	Location of Valve Inside/Outside Primary Containment	Length of Pipe - Containment to Outside Isolation Valve	Type Test	Potential Bypass Leakage Path	Valve [illegible]	[illegible]	Type	Operator	Actuation Primary	Actuation Secondary	Normal	Shutdown	Post-Accident	Power Failure	Isolation Signal	Closure Time	Power Source	Notes
[illegible]	[illegible]	[illegible]	55	No	Water	12	6.2-70 Sh. 13	Outside	6'-0"	C	[illegible]	[illegible]	[illegible]	Globe	MOV	Elec.	Manual	Closed	Open	Closed	FAI	[illegible]	25	Div I	11
								Inside		C		[illegible]	[illegible]	Check	AOV	Process	Air (Test only)	Closed	Open	Closed	Closed	[illegible]	N/A	Div I	
[illegible]		[illegible]	55	No	Water	2	6.2-70 Sh. 13	Inside		C		[illegible]	[illegible]	Globe	MOV	Elec.	Manual	Closed	Closed	Closed	FAI	[illegible]	9	Div I	
[illegible]		[illegible]	55	No	Water	12	6.2-70 Sh. 13	Outside	6'-0"	C	[illegible]	[illegible]	[illegible]	Globe	MOV	Elec.	Manual	Closed	Open	Closed	FAI	[illegible]	25	Div II	11
								Inside		C		[illegible]	[illegible]	Check	AOV	Process	Air (Test only)	Closed	Open	Closed	Closed	[illegible]	N/A	Div II	
[illegible]		[illegible]	55	No	Water	2	6.2-70 Sh. 13	Inside		C		[illegible]	[illegible]	Globe	MOV	Elec.	Manual	Closed	Closed	Closed	FAI	[illegible]	9	Div II	
[illegible]	[illegible]	[illegible]	55	No	Water	20	6.2-70 Sh. 16	Outside	6'-0"	C	[illegible]	[illegible]	[illegible]	Gate	MOV	Elec.	Manual	Closed	Open	Closed	FAI	[illegible]	27	Div I	
								Inside		C		[illegible]	[illegible]	Gate	MOV	Elec.	Manual	Closed	Open	Closed	FAI	[illegible]	27	Div II	
								Inside		C		[illegible]	-	Relief	N/A	Auto	N/A	Closed	Closed	Closed	Closed	N/A	N/A	N/A	
[illegible]	[illegible]	[illegible]	56	Yes	Water	20	6.2-70 Sh. 5	Outside	2'-2"	C C	Yes[illegible]	[illegible]	[illegible]	Gate	MOV	Elec.	Manual	Closed	Closed	Open	FAI	[illegible]	10	Div III	11
[illegible]	[illegible]	[illegible]	56	Yes	Water	12	6.2-70 Sh. 35	Outside	58'-0"	C	[illegible]	[illegible]	[illegible]	Globe	MOV	Elec.	Manual	Closed	Closed	Closed	FAI	[illegible]	60	Div III	
		[illegible]		Yes	Water	[illegible]		Outside	[illegible]	C		[illegible]	[illegible]	Gate	MOV	Elec.	Manual	Closed	Closed	Closed	FAI	[illegible]	5	Div III	

Table A.2.1 (Continued)

	Penetration No.	System Description	GDC or Reg. Guide	ESF System	Fluid	Size (in.)	FSAR Arrangement Figure	Location of Valve Inside/Outside Primary Containment	Length of Pipe - Containment to Outside Isolation Valve	Type Test	Potential Bypass Leakage Path	Valve Number MPL	Valve Number SS	Valve Type	Operator	Actuation Mode Primary	Actuation Mode Secondary	Position Normal	Position Shutdown	Position Post-Accident	Position Power Failure	Isolation Signal	Closure Time	Power Source	Notes	
*	Z-14	CSH to RPV	55	Yes	Water	12	6.2-70 Sh. 9	Inside		C	No	2CSH*AOV108	E22-F005	Check	AOV	Process	Air (Test only)	Closed	Closed	Open	Closed	Reverse flow	N/A	Div III	11,13	
								Outside	2'-0"	C		2CSH*MOV107	E22-F004	Gate	MOV	Elec.	Manual	Closed	Closed	Open	FAI	RM	12	Div III		
E	Z-15	CSL suction from suppression pool	56	Yes	Water	20	6.2-70 Sh. 8	Outside	3'-9"	C	No	2CSL*MOV112	E21-F001	Butterfly	MOV	Elec.	Manual	Open	Open	Open	FAI	RM	90	Div I	11	|
*	Z-16	CSL to RPV	55	Yes	Water	12	6.2-70 Sh. 10	Inside		C	No	2CSL*AOV101	E21-F006	Check	AOV	Process	Air (Test only)	Closed	Closed	Open	Closed	Reverse flow	N/A	Div I	11,13	
								Outside	1'-0"	C		2CSL*MOV104	E21-F005	Gate	MOV	Elec.	Manual	Closed	Closed	Open	FAI	RM	16	Div I		
E	Z-17	ICS suction line suppression pool	56	Yes	Water	6	6.2-70 Sh. 5	Outside	0'-9"	C	Yes	2ICS*MOV136	E51-F031	Gate	MOV	Elec.	Manual	Closed	Closed	Open	FAI	RM	19	125VDC		|
E	Z-18	ICS minimum flow line to suppression pool	56	Yes	Water	2	6.2-70 Sh. 11	Outside	0'-6"	C	No	2ICS*MOV143	E51-F019	Globe	MOV	Elec.	Manual	Closed	Closed	Closed	FAI	RM	5	125VDC		|
E	Z-19	ICS turbine exhaust to suppression pool	56	Yes	Steam	12	6.2-70 Sh. 12	Outside	1'-6"	C	No	2ICS*MOV122	E51-F068	Gate	MOV	Elec.	Manual	Open	Open	Open	FAI	RM	65	125VDC	16	|
	Z-20	Spare		No		3/4				A																

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Table A.2.1 (Continued)

	Penetration No.	System Description	GDC or Reg. Guide	ESF System	Fluid	Size (in)	FSAR Arrangement Figure(s)	Location of Valve Inside/Outside Primary Containment	Length of Pipe – Containment to Outside Isolation Valve	Type Test	Potential Bypass Leakage Path	Valve Number [illegible]	Valve Number [illegible]	Type	Operator	Actuation Mode Primary	Actuation Mode Secondary	Position Normal	Position Shutdown	Position Post-Accident	Position Power Failure	Isolation Signal	Closure Time	Power Source	Notes
A	[illegible]	[illegible]	55	Yes	Steam	10	6.2-70 Sh. 16	Outside Inside	[illegible]	C C	[illegible]	2ICS*MOV121 2ICS*MOV128	[illegible]	Gate Gate	MOV MOV	Elec. Elec.	Manual Manual	Open Open	Closed Closed	Open Open	FAI FAI	[illegible]	10 10	Div I Div. II	
A		[illegible]			Steam			Inside		C	[illegible]	2ICS*MOV170	[illegible]	Globe	MOV	Elec.	Manual	Closed	Closed	Closed	FAI	[illegible]	5	Div. II	
	[illegible]	Spare		No		[illegible]				A															
*	[illegible]	[illegible]	55	Yes	Water	6	6.2-70 Sh. 17	Outside	[illegible]	C	[illegible]	2ICS*AOV156	[illegible]	Check	AOV	Process	Air (Test only)	Closed	Open	Open	Closed	Rev flow N/A		125VDC	
								Inside Outside	 [illegible]	C C		2ICS*AOV157 2ICS*MOV126	[illegible] [illegible]	Check Gate	AOV MOV	Process Elec.	Air (Test only) Manual	Closed Closed	Open Closed	Open Open	Closed FAI	Rev flow N/A [illegible]	 12	125VDC	[illegible]
*		[illegible]			Water	6	6.2-70 Sh. 17	Outside	[illegible]	C		[illegible]	[illegible]	Globe	MOV	Elec.	Manual	Closed	Open	Closed	FAI	[illegible]	[illegible]	Div I	[illegible]
A	[illegible]	[illegible]	55	No	Water Water	8 8	6.2-70 Sh. 18	Inside Outside	 [illegible]	C C	[illegible]	[illegible] [illegible]	[illegible] [illegible]	Globe Globe	MOV MOV	Elec. Elec.	Manual Manual	Open Open	Open Open	Closed Closed	FAI FAI	[illegible] [illegible]	[illegible] [illegible]	Div II Div I	[illegible]
	[illegible]	Spare		No		3				A															
B	[illegible]	[illegible]		Yes	Water	1 3/4	N/A	Outside Outside	[illegible] [illegible]		[illegible]							See Note 17							
B	[illegible]	[illegible]		Yes	Water	1 3/4	N/A	Outside Outside	[illegible] [illegible]		[illegible]							See Note 17							
B	[illegible]	[illegible]		Yes	Water	1 3/4	N/A	Outside Outside	[illegible] [illegible]		[illegible]							See Note 17							

Table A.2.1 (Continued)

	Pene-tration No.	System Description	GDC or Reg. Guide	ESF System	Fluid	Line Size (in)	FSAR Arrange-ment Figure	Location of Valve Inside/Outside Primary Contain-ment	Length of Pipe - Containment to Outside Isolation Valve	Type Test	Potential Bypass Leakage Path	Valve No. P&ID	Valve No. SS	Type	Oper-ator	Actuation Mode Primary	Actuation Mode Secondary	Position Normal	Position Shutdown	Position Post-Accident	Position Power Failure	Isolation Signal	Closure Time (sec)	Power Source	Notes
B	Z-28	[illegible] to [illegible] 10 lines at [illegible]		Yes							[illegible]							See Note 17							
					Water	1 3/8	N/A	Outside Outside	125'-0" 125'-0"																
B	Z-29	SLCS to RPV	55	Yes	Boron solu-tion	1 1/2	6.2-70 Sh. 43	Inside Outside	2'-10"	C C	No(3)	2SLS*V10 2SLS*MOV5A	C41-F007 C41-F006A	Check Stop check globe	N/A MOV	Process Elec.	N/A Manual	Closed Closed	Closed Closed	Closed Closed	N/A Closed	Reverse flow Reverse flow	N/A N/A	N/A N/A	
								Outside	2'-10"	C		2SLS*MOV5B	C41-F006B	Stop check globe	MOV	Elec.	Manual	Closed	Closed	Closed	Closed	Reverse flow	N/A	N/A	
	Z-30A	Spare		No		3				A															
	Z-30B	Spare		No		3				A															
B	Z-31A	TIP drive guide tube to RPV	57	No	Note 19	1 1/2	6.2-70 Sh. 19	Outside Outside	2'-0"	C C	No(3)	N/A N/A	C51-J004 C51-J004	Ball Shear	SOV N/A	Elec. N/A	N/A N/A	Closed Open	Closed Open	Closed Open	Closed Open	B,F,RM RM	N/A N/A	120 VAC 125 VDC	18,19, 20,16
B	Z-31B	TIP drive guide tube to RPV	57	No	Note 19	1 1/2	6.2-70 Sh. 19	Outside Outside	2'-0"	C C	No(3)	N/A N/A	C51-J004 C51-J004	Ball Shear	SOV N/A	Elec. N/A	N/A N/A	Closed Open	Closed Open	Closed Open	Closed Open	B,F,RM RM	N/A N/A	120 VAC 125 VDC	18,19 20,16
B	Z-31C	TIP drive guide tube to RPV	57	No	Note 19	1 1/2	6.2-70 Sh. 19	Outside Outside	2'-0"	C C	No(3)	N/A N/A	C51-J004 C51-J004	Ball Shear	SOV N/A	Elec. N/A	N/A N/A	Closed Open	Closed Open	Closed Open	Closed Open	B,F,RM RM	N/A N/A	120 VAC 125 VDC	18,19 20,16
B	Z-31D	TIP drive guide tube to RPV	57	No	Note 19	1 1/2	6.2-70 Sh. 19	Outside Outside	2'-0"	C C	No(3)	N/A N/A	C51-J004 C51-J004	Ball Shear	SOV N/A	Elec. N/A	N/A N/A	Closed Open	Closed Open	Closed Open	Closed Open	B,F,RM RM	N/A N/A	120 VAC 125 VDC	18,19 20,16
B	Z-31E	TIP drive guide tube to RPV	57	No	Note 19	1 1/2	6.2-70 Sh. 19	Outside Outside	2'-0"	C C	No(3)	N/A N/A	C51-J004 C51-J004	Ball Shear	SOV N/A	Elec. N/A	N/A N/A	Closed Open	Closed Open	Closed Open	Closed Open	B,F,RM RM	N/A N/A	120 VAC 125 VDC	18,19, 20,16
B	Z-32	N_2 purge to TIP index mechanism	56	No	N_2	1 1/2	6.2-70 Sh. 42	Outside	7'-6"	C	No(3)	2GSN*V160	-	Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow	N/A	N/A	30
								Outside	6'-3"	C		2GSN*V169	-	Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow	N/A	N/A	
								Inside	-	C		2GSN*V170	-	Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow	N/A	N/A	
E	Z-33A	CCP supply to RCS Pump A	56	No	Water	8	6.2-70 Sh. 20	Inside Outside	3'-0"	C C	No(3)	2CCP*MOV94A 2CCP*MOV17A	- -	Gate Gate	MOV MOV	Elec. Elec.	Manual Manual	Open Open	Open Open	Closed Closed	FAI FAI	B,F,RM B,F,RM	28 33	Div II Div I	6

Table A.2.1 (Continued)

	Penetration No.	System Description	GDC or Reg. Guide	ESF System	Fluid	Size (in)	FSAR Arrangement Figure	Location of Valve Inside/Outside Primary Containment	Length of Pipe	Type Test	Potential Bypass Leakage Path	Valve Number		Type	Operator	Actuator Mode Primary	Actuator Mode Secondary	Position Normal	Position Shutdown	Position Post-Accident	Position Power Failure	Isolation Signal	Closure Time	Power Source	Notes
E	[illegible]	[illegible]	56	No	Water	6	6.2-70 Sh. 20	Inside		C	[illegible]	[illegible]	-	Gate	MOT	Elec.	Manual	Open	Open	Closed	[illegible]	[illegible]	40	Div II	
								Outside	[illegible]	C		[illegible]	-	Gate	MOT	Elec.	Manual	Open	Open	Closed	[illegible]	[illegible]	20	Div I	
								Inside		N/A		[illegible]	-	Relief	N/A	Auto	N/A	Closed	Closed	Closed	N/A	N/A	N/A	N/A	
E	[illegible]	[illegible]	56	No	Water	6	6.2-70 Sh. 21	Inside		C	[illegible]	[illegible]	-	Gate	MOT	Elec.	Manual	Open	Open	Closed	[illegible]	[illegible]	20	Div II	
								Outside	[illegible]	C		[illegible]	-	Gate	MOT	Elec.	Manual	Open	Open	Closed	[illegible]	[illegible]	20	Div I	
E	[illegible]	[illegible]	56	No	Water	6	6.2-70 Sh. 21	Inside		C	[illegible]	[illegible]	-	Gate	MOT	Elec.	Manual	Open	Open	Closed	FAI	[illegible]	20	Div II	
								Outside	[illegible]	C		[illegible]	-	Gate	MOT	Elec.	Manual	Open	Open	Closed	FAI	[illegible]	20	Div I	
								Inside		N/A		[illegible]	-	Relief	N/A	Auto	N/A	Closed	Closed	Closed	N/A	N/A	N/A	N/A	
	[illegible]	Spare																							
E	[illegible]	Service air to drywell	56	No	Air	2	6.2-70 Sh. 22	Outside	[illegible]	C	[illegible]	[illegible]	-	Globe	Manual	Manual	N/A	Closed	Open	Closed	N/A	[illegible]	N/A	Div I	
								Inside				[illegible]	-	Globe	Manual	Manual	N/A	Closed	Open	Closed	N/A	[illegible]	N/A	Div II	
E	[illegible]	Breathing air to drywell	56	No	Air	2	6.2-70 Sh. 22	Outside	[illegible]	C	[illegible]	[illegible]	-	Globe	Manual	Manual	N/A	Closed	Open	Closed	N/A	[illegible]	N/A	Div I	
								Inside		C		[illegible]	-	Globe	Manual	Manual	N/A	Closed	Open	Closed	N/A	[illegible]	N/A	Div II	
B	[illegible]	[illegible]	55	No	Water	3/4	6.2-70 Sh. 23	Inside		C	[illegible]	[illegible]	[illegible]	Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow	N/A	N/A	
								Outside	[illegible]	C		[illegible]	[illegible]	Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow	N/A		
								Outside	[illegible]			[illegible]	[illegible]	Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow	N/A		
B	[illegible]	[illegible]	55	No	Water	3/4	6.2-70 Sh. 23	Inside		C	[illegible]	[illegible]	[illegible]	Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow	N/A	N/A	
								Outside	[illegible]	C		[illegible]	[illegible]	Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow	N/A		
								Outside	[illegible]			[illegible]	[illegible]	Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow	N/A		
E	[illegible]	Drywell floor drain tank [illegible]	56	No	Air	6	6.2-70 Sh. 24	Inside		C	[illegible]	[illegible]	-	Gate	MOT	Elec.	Manual	Open	Closed	Closed	FAI	[illegible]	20	Div II	
								Outside	[illegible]	C		[illegible]	-	Gate	MOT	Elec.	Manual	Open	Closed	Closed	FAI	[illegible]	20	Div I	
E	[illegible]	[illegible] drains from drywell	56	No	Water	4	6.2-70 Sh. 24	Inside		C	[illegible]	[illegible]	-	Gate	MOT	Elec.	Manual	Open	Closed	Closed	FAI	[illegible]	[illegible]	Div II	
								Outside	[illegible]	C		[illegible]	-	Gate	MOT	Elec.	Manual	Open	Closed	Closed	FAI	[illegible]	[illegible]	Div I	

Table A.2.1 (Continued)

	Penetration No.	System Description	GDC or Reg. Guide	ESF System	Fluid	Line Size (in)	FSAR Arrangement Figure	Location of Valve Inside/Outside Primary Containment	Length of Pipe - Containment to Outside Isolation Valve	Type Test	Potential Bypass Leakage Path
E	Z-41	Reactor coolant sample to sample cooler	55	No	Water	3/4	6.2-70 Sh. 23	Inside Outside	0'-0"	C C	No
E	Z-42B	Fire protection for reactor recirc pump	56	No	Water	2	6.2-70 Sh. 26	Inside Outside	3'-8"	C C	No
E	Z-42A	Fire protection water for reactor recirc pump	56	No	Water	2	6.2-70 Sh. 26	Inside Outside	3'-8"	C C	No
E	Z-43	Drywell floor drains	56	No	Water	4	6.2-70 Sh. 27	Inside Outside	30'-10"	C C	Yes
	Z-44A	Capped spare				3				A	
	Z-44B	Capped spare				3				A	
	Z-44C	Capped spare				3				A	
	Z-44D	Capped spare				3				A	
E	Z-46	Service air to drywell	56	No	Air	2	6.2-70 Sh. 22	Outside Inside	0'-5"	C C	No
E	Z-44	Breathing air to drywell	56	No	Air	2	6.2-70 Sh. 22	Outside Inside	0'-5"	C C	No
E	Z-45	Equipment drain sump (2DFR-TK1) vent to drywell	56	No	Air	2	6.2-70 Sh. 27	Inside Outside	0'-0"	C C	Yes
E	Z-46A	CCP supply to drywell space cooler	56	No	Water	6	6.2-70 Sh. 28	Inside Outside	3'-0"	C C	No

Penetration No.	Valve Number	Valve Mark No.	Type	Operator	Actuation Mode Primary	Actuation Mode Secondary	Position Normal	Position Shutdown	Position Post-Accident	Position Power Failure	Isolation Signal	Closure Time (s)	Power Source	Notes
Z-41	2RCS*SOV104 2RCS*SOV105	B35-F019 B35-F020	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Closed Closed	Closed Closed	Closed Closed	Closed Closed	B,C,RM B,C,RM	N/A N/A	Div II Div I	
Z-42B	2FPW*SOV219 2FPW*SOV218	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Closed Closed	Closed Closed	Closed Closed	Closed Closed	B,F,RM B,F,RM	N/A N/A	Div II Div I	
Z-42A	2FPW*SOV221 2FPW*SOV220	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Closed Closed	Closed Closed	Closed Closed	Closed Closed	B,F,RM B,F,RM	N/A N/A	Div II Div I	
Z-43	2DFR*MOV120 2DFR*MOV119	- -	Gate Gate	MOT MOT	Elec. Elec.	Manual Manual	Open Open	Closed Closed	Closed Closed	FAI FAI	B,F,RM B,F,RM	13 13	Div II Div I	
Z-44A														
Z-44B														
Z-44C														
Z-44D														
Z-46	2SAS*MCV160 2SAS*MCV162	- -	Globe Globe	Manual Manual	Manual Manual	N/A N/A	Closed Closed	Open Open	Closed Closed	N/A N/A	LNC,LC LNC,LC	N/A N/A	Div I Div II	
Z-44	2IAS*MCV135 2IAS*MCV137	- -	Globe Globe	Manual Manual	Manual Manual	N/A N/A	Closed Closed	Open Open	Closed Closed	N/A N/A	LNC,LC LNC,LC	N/A N/A	Div I Div II	
Z-45	2DER*AOV110 2DER*AOV131	- -	Globe Globe	AOV AOV	Elec. Elec.	Manual Manual	Open Open	Closed Closed	Closed Closed	FAI FAI	B,F,RM B,F,RM	9 9	Div II Div I	
Z-46A	2CCP*MOV273 2CCP*MOV265	- -	Gate Gate	MOT MOT	Elec. Elec.	Manual Manual	Open Open	Open Open	Closed Closed	FAI FAI	B,F,RM B,F,RM	36 36	Div II Div I	

Table A.2.1 (Continued)

Penetration Number	System Description	GDC or Reg. Guide	ESF System	Fluid	Line Size (in.)	FSAR Arrangement Figure	Location of Valve Inside/Outside Primary Containment	Length of Pipe - Containment to Outside Isolation Valve	Type Test	Potential Bypass Leakage Path	Valve Mark No.	Note	Type	Operator	Actuator Mode Primary	Actuator Mode Secondary	Position Normal	Position Shutdown	Position Post-Accident	Position Power Failure	Isolation Signal	Closure Time (sec)	Power Source	Notes
Z-46A	Capped spare				[illegible]				A															
E Z-46C	Fire protection water for containment hose reel standpipe						See Note 30			No														
Z-46D	Capped spare				[illegible]				A															
E Z-47	CCP return from drywell space cooler	57	No	Water	8	6.2-70 Sh. 20	Inside Outside	 7'-3"	C C	No	2CCP*MOV122 2CCP*MOV124	- -	Gate Gate	MOV MOV	Elec. Elec.	Manual Manual	Open Open	Open Open	Closed Closed	FAI FAI	B,F,RM B,F,RM	36 36	Div II Div I	
E Z-48	Purge exhaust from drywell	56	No	Air	14	6.2-70 Sh. 29	Inside Outside	- 7'-6"	C C	No	2CPS*AOV108 2CPS*AOV110	- -	Butterfly Butterfly	AOV AOV	Pneumatic Pneumatic	Manual Manual	Closed Closed	Closed Closed	Closed Closed	Closed Closed	B,F,Z,RM B,F,Z,RM	5 5	Div II Div I	
E Z-49	Purge inlet to drywell	56	No	Air/N_2	14	6.2-70 Sh. 29	Inside Outside	- 6'-0"	C C	Yes	2CPS*AOV106 2CPS*AOV104	- -	Butterfly Butterfly	AOV AOV	Pneumatic Pneumatic	Manual Manual	Closed Closed	Closed Closed	Closed Closed	Closed Closed	B,F,Z,RM B,F,Z,RM	5 5	Div II Div I	21
E Z-50	Purge inlet to wetwell	56	No	Air/N_2	12	6.2-70 Sh. 29	Inside Outside	- 6'-3"	C C	Yes	2CPS*AOV107 2CPS*AOV105	- -	Butterfly Butterfly	AOV AOV	Pneumatic Pneumatic	Manual Manual	Closed Closed	Closed Closed	Closed Closed	Closed Closed	B,F,Z,RM B,F,Z,RM	5 5	Div II Div I	
E Z-51	Purge exhaust from wetwell	56	No	Air	12	6.2-70 Sh. 29	Inside Outside	- 6'-6"	C C	No	2CPS*AOV109 2CPS*AOV111	- -	Butterfly Butterfly	AOV AOV	Pneumatic Pneumatic	Manual Manual	Closed Closed	Closed Closed	Closed Closed	Closed Closed	B,F,Z,RM B,F,Z,RM	5 5	Div II Div I	
Z-52A	Capped spare				1				A															
Z-52B	Capped spare				1				A															
E Z-52[illegible]	Instrument air to ADS valve accumulators	56	No	N_2	1 1/2	6.2-70 Sh. 30	Outside Inside	1'-6" 	C C	 Yes	2IAS*SOV164 2IAS*V448	- -	Globe Check	AOV N/A	Elec. Process	N/A N/A	Open Open	Open Open	Open Open	Closed N/A	B,F,RM Reverse flow	N/A N/A	Div I N/A	

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Table A.2.1 (Continued)

	Penetration No.	System Description	GDC or Reg. Guide	ESF System	Fluid	Line Size (in)	FSAR Arrangement Figure	Location of Valve Inside/Outside Primary Containment	Length of Pipe - Containment to Outside Isolation Valve	Type Test	Potential Bypass Leakage Path	Valve Number	SI	Type	Operator	Actuation Mode Primary	Actuation Mode Secondary	Position Normal	Position Shutdown	Position Post-Accident	Position Power Failure	Isolation Signal	Closure Time (sec)	Power Source	Notes
E	Z-53B	Instrument air to ADS valve accumulators	56	No	N_2	1 1/2	6.2-70 Sh. 30	Outside Inside	1'-0"	C C	Yes(40)	2IAS*SOV165 2IAS*V449	- -	Globe Check	SOV N/A	Elec. Process	N/A N/A	Open Open	Open Open	Open Open	Closed N/A	B,F,RM Process flow	N/A N/A	Div II N/A	
E	Z-53C	Instrument air to ADS accumulator tank	56	No	N_2	1 1/2	6.2-70 Sh. 30	Outside Inside	1'-0"	C C	Yes(40)	2IAS*SOV166 2IAS*SOV184	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Open Open	Closed Closed	Closed Closed	B,F,RM B,F,RM	N/A N/A	Div I Div II	
	Z-54A	Capped Spare				3				A															
E	Z-55A	Hydrogen recombiner 1A supply to wetwell	56	Yes	Air	3	6.2-70 Sh. 31	Inside Outside	2'-0"	A, C A, C	No(31)	2HCS*MOV4A 2HCS*MOV1A	- -	Globe Globe	MOT MOT	Elec. Elec.	Manual Manual	Closed Closed	Closed Closed	Open Open	FAI FAI	B,F,RM B,F,RM	19 19	Div I Div I	12, 22
E	Z-55B	Hydrogen recombiner 1B supply to wetwell	56	Yes	Air	3	6.2-70 Sh. 31	Inside Outside	2'-0"	A, C A, C	No(31)	2HCS*MOV4B 2HCS*MOV1B	- -	Globe Globe	MOT MOT	Elec. Elec.	Manual Manual	Closed Closed	Closed Closed	Open Open	FAI FAI	B,F,RM B,F,RM	19 19	Div II Div II	12, 22
E	Z-56A	Hydrogen recombiner 1A return from drywell	56	Yes	Air	3	6.2-70 Sh. 31	Inside Outside	2'-0"	A, C A, C	No(31)	2HCS*MOV6A 2HCS*MOV3A	- -	Globe Globe	MOT MOT	Elec. Elec.	Manual Manual	Closed Closed	Closed Closed	Open Open	FAI FAI	B,F,RM B,F,RM	19 19	Div I Div I	12, 22
E	Z-56B	Hydrogen recombiner 1B return from drywell	56	Yes	Air	3	6.2-70 Sh. 31	Inside Outside	2'-0"	A, C A, C	No(31)	2HCS*MOV6B 2HCS*MOV3B	- -	Globe Globe	MOT MOT	Elec. Elec.	Manual Manual	Closed Closed	Closed Closed	Open Open	FAI FAI	B,F,RM B,F,RM	19 19	Div II Div II	12, 22
E	Z-57A	Hydrogen recombiner 1A return from wetwell	56	Yes	Air	3	6.2-70 Sh. 31	Inside Outside	2'-0"	A, C A, C	No(31)	2HCS*MOV5A 2HCS*MOV2A	- -	Globe Globe	MOT MOT	Elec. Elec.	Manual Manual	Closed Closed	Closed Closed	Open Open	FAI FAI	B,F,RM B,F,RM	19 19	Div I Div I	12, 22
E	Z-57B	Hydrogen recombiner 1B return from wetwell	56	Yes	Air	3	6.2-70 Sh. 31	Inside Outside	2'-0"	A, C A, C	No(31)	2HCS*MOV5B 2HCS*MOV2B	- -	Globe Globe	MOT MOT	Elec. Elec.	Manual Manual	Closed Closed	Closed Closed	Open Open	FAI FAI	B,F,RM B,F,RM	19 19	Div II Div II	12, 22
E	Z-58	Containment purge to drywell	56	No	Air	2	6.2-70 Sh. 29	Inside Outside	2'-0"	C C	Yes	2CPS*SOV122 2CPS*SOV120	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Closed Closed	Closed Closed	Closed Closed	Closed Closed	B,D,F RM B,F,Z RM	N/A N/A	Div II Div I	

Table A.2.1 (Continued)

	Penetration No.	System Description	GDC or Reg. Guide	ESF System	Fluid	Size (in.)	FSAR Arrangement Figure	Location of Valve Inside/Outside Primary Containment	Length of Pipe - Containment to Outside Isolation Valve	Type Test	Potential Bypass Leakage Path	Valve Number	Note	Valve Type	Operation	Actuation Mode Primary	Actuation Mode Secondary	Position Normal	Position Shutdown	Position Post-Accident	Position Power Failure	Isolation Signal	Closure Time	Power Source	Notes
E	2-59	Containment purge to wetwell	56	No	Air	2	6.2-70 Sh. 29	Inside Outside	 10'-6"	C C	Yes	2CPS*SOV121 2CPS*SOV119	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Closed Closed	Closed Closed	Closed Closed	Closed Closed	[illegible] [illegible]	N/A N/A	Div II Div I	
E	2-60A	CMS from drywell	56	No	Air	3/4	6.2-70 Sh. 32	Inside Outside	 1'-2"	C C	No(11)	2CMS*SOV61A 2CMS*SOV60A	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Closed Open	Closed Closed	[illegible] [illegible]	N/A N/A	Div II Div I	
E	2-60B	CMS from drywell	56	Yes	Air	3/4	6.2-70 Sh. 32	Inside Outside	 1'-2"	C C	Yes(11)	2CMS*SOV74A 2CMS*SOV74C	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Open Open	Closed Closed	[illegible] [illegible]	N/A N/A	Div I Div I	
E	2-60C	CMS to drywell	56	No	Air	3/4	6.2-70 Sh. 32	Inside Outside	 8'-3"	C C	No(11)	2CMS*SOV63A 2CMS*SOV62A	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Closed Closed	Closed Closed	[illegible] [illegible]	N/A N/A	Div II Div I	
E	2-60D	CMS to drywell	56	Yes	Air	3/4	6.2-70 Sh. 32	Inside Outside	 8'-6"	C C	Yes(11)	2CMS*SOV73A 2CMS*SOV72A	- -	Globe Globe	SOV SOV	Elec. Elec.	Elec. N/A	Open Open	Closed Closed	Open Open	Closed Closed	[illegible] [illegible]	N/A N/A	Div I Div I	
E	2-60E	CMS from drywell	56	No	Air	3/4	6.2-70 Sh. 32	Inside Outside	 8'-3"	C C	No(11)	2CMS*SOV61B 2CMS*SOV60B	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Closed Closed	Closed Closed	[illegible] [illegible]	N/A N/A	Div II Div I	
E	2-60F	CMS from drywell	56	Yes	Air	3/4	6.2-70 Sh. 32	Inside Outside	 8'-3"	C C	Yes(11)	2CMS*SOV74B 2CMS*SOV74D	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Open Open	Closed Closed	[illegible] [illegible]	N/A N/A	Div II Div II	
E	2-60G	CMS to drywell	56	No	Air	3/4	6.2-70 Sh. 32	Inside Outside	 6'-3"	C C	No(11)	2CMS*SOV63B 2CMS*SOV62B	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Closed Closed	Closed Closed	[illegible] [illegible]	N/A N/A	Div II Div I	
E	2-60H	CMS to drywell	56	Yes	Air	3/4	6.2-70 Sh. 32	Inside Outside	 1'-6"	C C	Yes(11)	2CMS*SOV73B 2CMS*SOV72B	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Open Open	Closed Closed	[illegible] [illegible]	N/A N/A	Div II Div II	
	2-61A	Capped spare				3/4				A															
E	2-61B	CMS from wetwell	56	Yes	Air	3/4	6.2-70 Sh. 32	Inside Outside	 15'-6"	C C	No(11)	2CMS*SOV76A 2CMS*SOV76C	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Open Open	Closed Closed	[illegible] [illegible]	N/A N/A	Div I Div I	
E	2-61C	CMS to wetwell	56	Yes	Air	3/4	6.2-70 Sh. 32	Inside Outside	 10'-3"	C C	No(11)	2CMS*SOV[illegible]A 2CMS*SOV[illegible]A	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Open Open	Closed Closed	[illegible] [illegible]	N/A N/A	Div I Div I	
	2-61D	Capped spare				3/4				A															
E	2-61E	CMS from wetwell	56	Yes	Air	3/4	6.2-70 Sh. 32	Inside Outside	 6'-6"	C C	No(11)	2CMS*SOV76B 2CMS*SOV76D	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Open Open	Closed Closed	[illegible] [illegible]	N/A N/A	Div II Div II	

Table A.2.1 (Continued)

	Penetration No.	System Description	GDC or Reg. Guide	ESF System	Fluid	Size (in.)	FSAR Arrangement Figure	Location of Valve Inside/Outside Primary Containment	Length of Pipe - Containment to Outside Isolation Valve	Type Test	Potential Bypass Leakage Path	Valve No.		Valve Type	Operator	Actuation Mode Primary	Actuation Mode Secondary	Normal Position	Shutdown Position	Post-Accident Position	Power Failure Position	Isolation Signal	Closure Time	Power Source	Notes
E	[illegible]	[illegible]	56	Yes	Air	3/4	6.2-70 Sh. 32	Inside Outside	[illegible]	C C	No(3)	[illegible] [illegible]	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Open Open	Closed Closed	[illegible] [illegible]	N/A N/A	[illegible] [illegible]	
	2-67	Spare				10				A															
	2-68	Capped spare				10				A															
	2-69	Spare				6																			
	2-70	Capped spare				6				A															
	2-71	Spare				3				A															
	2-72	Capped spare				10				A															
E	2-73	[illegible]	56	No	Water	6	6.2-70 Sh. 13	Outside	[illegible]	A	No(3)	[illegible] [illegible]	[illegible] [illegible]	[illegible]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	[illegible]	N/A	N/A	
	2-74	Capped spare				6				A															
	2-75	Capped spare				3				A															
	2-76	Capped spare				3				A															
	2-77	Capped spare				1 1/2				A															
	2-78	Capped spare				1 1/2				A															
	2-79	Capped spare				1 1/2				A															
E	2-80	Spent fuel pool cooling	56	No	Water	1 1/2	6.2-70 Sh. 40	Outside Inside	[illegible]	C C	No(3)	[illegible] [illegible]	- -	Globe Globe	Manual Manual	Manual Manual	N/A N/A	Closed Closed	Closed Closed	Closed Closed	N/A N/A	LC LC	N/A N/A	N/A N/A	
	2-81	Capped spare				1 1/2				A															
	2-82	Capped spare				1				A															

Table A.2.1 (Continued)

Nine Mile Point Unit 2 FSAR

	Penetration No.	System Description	GDC or Reg. Guide	ESF System	Fluid	Size (in)	FSAR Arrangement Figure	Location of Valve Inside/Outside Primary Containment	Length of Pipe - Containment to Outside Isolation Valve	Type Test	Potential Bypass Leakage Path	Valve Mark No.	Valve Notes	Type	Operator	Actuation Mode Primary	Actuation Mode Secondary	Position Normal	Position Shutdown	Position Post-Accident	Position Power Failure	Isolation Signal	Closure Time	Power Source	Notes
	Z-53	Capped spare				1				A															
	Z-65	Capped spare				1				A															
	Z-66	Capped spare				1				A															
	Z-67	Capped spare				1				A															
E	Z-44A	RHS safety valve discharge to suppression pool	56	Yes	Steam	12	6.2-70 Sh. 34	Outside	116'-3"	A	No(19)	See Note 23													
E	Z-39B	RHS safety valve discharge to suppression pool	56	Yes	Steam	12	6.2-70 Sh. 34	Outside	186'-3"	A	No(19)	See Note 24													
E	Z-89A	ISS from dry-well	56	No	Air	3/4	6.2-70 Sh. 35	Inside Outside	0'-2"	C C	No(19)	2ISS*SOV152 2ISS*SOV153	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Closed Closed	Closed Closed	Closed Closed	Closed Closed	B,F,RM B,F,RM	N/A N/A		Div II Div I
	Z-89B	Capped spare				3/4				A															
E	Z-89C	ISS from wet-well	56	No	Air	3/4	6.2-70 Sh. 35	Inside Outside	0'-2"	C C	No(19)	2ISS*SOV156 2ISS*SOV157	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Closed Closed	Closed Closed	Closed Closed	Closed Closed	B,F,RM B,F,RM	N/A N/A		Div II Div I
	Z-93B	Capped spare				3/4				A															
E	Z-93	ICS oxygen [illegible]	56	Yes	Air	1 1/2	6.2-70 Sh. 36	Outside Outside	23'-10" 23'-11"	C C	No(19)	2ICS*MOV158 2ICS*MOV160	ESI-F086 ESI-F000	Globe Globe	MOV MOV	Elec. Elec.	Manual Manual	Open Open	Closed Closed	Open Open	FAI FAI	FCM,RM FCM,RM	9 9		Div II Div I
E	Z-91A	Instrument air to dry-well	56	No	N_2	1 1/2	6.2-70 Sh. 37	Outside Inside	1'-0"	C C	Yes(19)	2IAS*SOV167 2IAS*SOV135	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Open Open	Closed Closed	Closed Closed	B,F,RM B,F,RM	N/A N/A		Div I Div II
E	Z-91B	Instrument air to dry-well	56	No	N_2	1 1/2	6.2-70 Sh. 37	Outside Inside	1'-0"	C C	Yes(19)	2IAS*SOV168 2IAS*SOV166	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Open Open	Closed Closed	Closed Closed	B,F,RM B,F,RM	N/A N/A		Div I Div II
	Z-91C	Capped spare				1 1/2				A															
	Z-91D	Capped spare				1 1/2				A															

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Table A.2.1 (Continued)

Nine Mile Point Unit 2 FSAR

	Pene-tration No.	System Description	GDC or Reg. Guide	ESF System	Fluid	Size (in.)	FSAR Arrange-ment Figure	Location of Valve Inside/Outside Primary Contain-ment	Length of Pipe - Con-tainment to Outside Isolation Valve	Type Test	Potential Bypass Leakage Path	Valves: Number		Type	Oper-ator	Actuator Mode: Primary	Secondary	Position: Normal	Shutdown	Post-Accident	Power Failure	Isola-tion Signal	Closure Time	Power Source	Notes
	Z-52	Spare				3				A															
	Z-96	Spare								A															
E	Z-97A	RHS relief valve discharge to suppression pool	56	Yes	Water	3	6.2-70 Sh. 38	Outside	207'-6"	A	[illegible]	[illegible]	[illegible]	Relief Valves	N/A	N/A	N/A	N/A	N/A	N/A	N/A	None	N/A	N/A	
E	Z-90B	RHS relief valve discharge to suppression pool	56	Yes	Water	3	6.2-70 Sh. 38	Outside	89'-8"	A	[illegible]	[illegible]	[illegible]	Relief Valves	N/A	N/A	N/A	N/A	N/A	N/A	N/A	None	N/A	N/A	
E	Z-99A	Hydraulic unit from recirc flow control valve RCS 37A (close line)	56	No	Hy-draulic	3/8	6.2-70 Sh. 39	Outside Inside	0'-0" 0'-0"	N/A	[illegible]	[illegible]		Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Closed Closed	Closed Closed	[illegible]	N/A N/A	Div I Div II	26
E	Z-99B	Hydraulic unit to recirc flow control valve RCS 37A (open line)	56	No	Hy-draulic	1	6.2-70 Sh. 39	Outside Inside	0'-0" 0'-0"	N/A	[illegible]	[illegible]		Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Closed Closed	Closed Closed	[illegible]	N/A N/A	Div I Div II	26
E	Z-99C	Hydraulic unit to recirc flow control valve RCS 37A (pilot line)	56	No	Hy-draulic	1	6.2-70 Sh. 39	Outside Inside	0'-0" 0'-0"	N/A	[illegible]	[illegible]		Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Closed Closed	Closed Closed	[illegible]	N/A N/A	Div I Div II	26

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Table A.2.1 (Continued)

	Penetration No.	System Description	GDC or Reg. Guide	ESF System	Fluid	Size (in)	FSAR Arrangement Figure	Location of Valve Inside/Outside Primary Containment	Length of Pipe - Containment to Outside Isolation Valve	Type Test	Potential Bypass Leakage Path	Valve Mark No.	SI	Type	Operator	Actuator Primary	Actuator Secondary	Position Normal	Shutdown	Post-Accident	Power Failure	Isolation Signal	Closure Time	Power Source	Notes
E	Z-[illegible]	Hydraulic unit to recirc flow control valve HYV 17A (closed line)	56	No	Hydraulic	1	6.2-70 Sh. 39	Outside Inside	0'-0" 0'-0"	N/A	No	2RCS*SOV[illegible]A 2RCS*SOV[illegible]A	-	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Closed Closed	Closed Closed	B,F,PR B,F,PR	N/A N/A	Div I Div II	26
E	Z-100A	Hydraulic unit from recirc flow control valve HYV 17B (drain line)	56	No	Hydraulic	3/4	6.2-70 Sh. 39	Outside Inside	0'-0" 0'-0"	N/A	No	2RCS*SOV[illegible]B 2RCS*SOV[illegible]B	-	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Closed Closed	Closed Closed	B,F,PR B,F,PR	N/A N/A	Div I Div II	26
E	Z-[illegible]	Hydraulic unit to recirc flow control valve HYV 17B (open line)	56	No	Hydraulic	1	6.2-70 Sh. 39	Outside Inside	0'-0" 0'-0"	N/A	No	2RCS*SOV[illegible]B 2RCS*SOV[illegible]B	-	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Closed Closed	Closed Closed	B,F,PR B,F,PR	N/A N/A	Div I Div II	26
E	Z-104C	Hydraulic unit to recirc flow control valve HYV 17B (pilot line)	56	No	Hydraulic	1	6.2-70 Sh. 39	Outside Inside	0'-0" 0'-0"	N/A	No	2RCS*SOV[illegible]B 2RCS*SOV[illegible]B	-	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Closed Closed	Closed Closed	B,F,PR B,F,PR	N/A N/A	Div I Div II	26
E	Z-104B	Hydraulic unit to recirc flow control valve HYV 17B (closed line)	56	No	Hydraulic	1	6.2-70 Sh. 39	Outside Inside	0'-0" 0'-0"	N/A	No	2RCS*SOV[illegible]B 2RCS*SOV[illegible]B	-	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Closed Closed	Closed Closed	B,F,PR B,F,PR	N/A N/A	Div I Div II	26
		All instrument lines from reactor vessel	R.G. 1.11	No	Air/Water	3/4	6.2-70 Sh. 41	Outside	<10'-0"	A	No	EF check valves	-	EFV	N/A	Auto	N/A	Open	Open	Open	Open	Excess flow	N/A	N/A	27
		All instrument lines penetrating primary containment	R.G. 1.11	No	Air/Water	3/4	6.2-70 Sh. 41	Outside	<10'-0"	A	No	EFV	-	EFV	N/A	Auto	N/A	Open	Open	Open	Open	Excess flow	N/A	N/A	27

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A.3 Interfacing Lines at Quad Cities

The interfacing lines identified for Quad Cities are the following:

a. Shutdown Cooling Suction Line
b. Reactor Pressure Vessel Head Spray
c. LPCI Injection Lines
d. RCIC Pump Suction
e. Core Spray Injection Lines
f. HPCI Pump Suction

The interfacing lines are shown in Figures A.3.a-A.3.d. Tables A.3.1-A.3.8 list some data collected for them. Table A.3.9 lists the lines penetrating the containment. The single character code in the first column of the table denotes the disposition of the line. An asterisk denotes that the line is considered in the study. A letter means that the line is not further considered, based on the screening criterion denoted by the same letter in Section 2.1.

A.3.1 RHR-Reactor Shutdown Cooling

A.3.1.1 Automatic and Manual Control

The shutdown cooling mode of the RHR system is manually initiated from the control room and the two normally closed suction valves (1001-47 and 1001-50) leading to the RHR pumps are interlocked with RPV pressure. These valves can not be signaled open unless vessel pressure is at or below 100 psi. These valves perform the containment isolation function, from there the line splits into four lines and there is a third valve in each leg which then feeds one each of the four RHR pumps (see Figure A.3.a). The two isolation valves will automatically close on low reactor water level "A" or high RPV pressure (see Table A.3.1).

A.3.1.2 Indications of Overpressurization or Interfacing LOCA

The RHR shutdown cooling line is a 20" line from the B recirculation loop. This line becomes a low pressure line just downstream of the second isolation

valve (MOV 47). The low pressure piping that is vulnerable to full reactor pressure is bounded by the second isolation valve on one end and by the four normally closed RHR pump suction valves (MOV's 43A, B, C, and D) on the other. This section of piping is protected from moderate pressure excursions by a 1" pipe feeding a 1-1/2" valve set at 150 psig. Failure of this piping creates an unisolable LOCA outside the primary containment and all inventory out the break will be lost to the suppression pool for subsequent recirculation. Because MOVs 43A, B, C, and D are normally closed, the LPCI function of the RHR system will not be directly affected (i.e., the necessary piping will be intact). However, further information must be obtained from Quad Cities before a definitive statement can be made as to any failures that may occur due to the blowdown itself.

High space temperature alarms are provided along the shutdown cooling line to alert the operator to a break or leak in this line. It is not currently known if the instrumentation is qualified to function in the presence of the blowdown from an interfacing system LOCA.

A.3.2 Reactor Pressure Vessel Head Spray

A.3.2.1 Automatic and Manual Control

The reactor head spray line is used as part of the reactor shutdown cooling mode of the RHR systems. There are two normally closed motor-operated isolation valves in this line that can be opened manually from the control room when vessel pressure is less than 100 psi. There is also a check valve located downstream of the two isolation valves and nearest to the vessel (see Figure A.3.a). The two isolation valves will automatically close on either reactor low water level "A" or high reactor pressure (see Table A.3.2).

A.3.2.2 Indications of Overpressurization or Interfacing LOCA

The reactor head spray line is a 4" line that becomes low pressure just upstream of the two isolation valves (MOVs 60 and 63). The section of low pressure piping exposed by the failure of check valve 64 and the two isolation valves is protected by five relief valves. RV-59 is the first valve encountered

and is a 1" line set at 406 psig. The next two relief valves are on the loop A and loop B 18" headers (RV-22A and B, respectively) and are both 1" valves set at 408 psig. In parallel with RV-22A and B are the two RHR heat exchanger relief valves (RV-166A and B). These valves are each 1" with a setpoint of 450 psig.

For this particular 4" line, there would appear to be sufficient relief capacity to possibly prevent any pipe/equipment damage. However, in order to use the LPCI system, the loop crosstie would have to be closed by the operator so that the A loop would be isolated from the blowdown and the A loop relief valves would have to reseat. Operator awareness of this event could come from the high space temperature alarms associated with this line; however, with no line break, the temperature rise could be slow.

LPCI loop B piping can not be isolated from the interfacing valve failures. Depending on the actual failure modes of these valves, loop B may be rendered partially to fully impaired.

A.3.3 LPCI Injection Lines

A.3.3.1 Automatic and Manual Control

There are two LPCI injection lines and these lines are also used during the reactor shutdown cooling mode. The valve lineup for each line consists of an air operated check valve inside the drywell, a normally closed motor operated gate valve just outside the drywell and then, a normally open motor operated globe valve as the outboard isolation valve (see Figure A.3.a). The two series MOVs can be opened manually from the control room or automatically upon a safeguards initiation, however, RPV pressure must be below 375 psi.

A.3.3.2 Indications of Overpressurization or Interfacing LOCA

The LPCI lines are 16" and each comes off its own 18" header. the only difference between loop A and loop B is that the vessel head spray line also comes off the B header. Failure of the check valve and normally closed MOV will overpressurize both loops of LPCI as they are connected through a normally open

18" crosstie line. Each header has a relief valve sized at 1" and set at 408 psig. The vessel head spray line relief valve (RV-59) is also 1" and set at 408 psig. The piping back to the RHR pump discharge check valves will also be overpressurized. In each of these lines is a 1" relief valve on the RHR heat exchangers that will also provide some protection for this event. Given a small LOCA event, both LPCI loops are assumed unavailable due to the open crosstie piping.

A.3.4 RCIC Pump Suction

A.3.4.1 Automatic and Manual Control

The RCIC injection line feeds into the feedwater line at a point upstream of that lines' containment isolation valves. Therefore, in order to have an interfacing system LOCA, the two normally open (during operation) feedwater isolation valves (check valves) must fail to close in addition to the overpressurization failure of the RCIC system (see Table A.3.5). The valve lineup in the RCIC injection line consists of an air operated check valve, a normally closed MOV and a normally open MOV with both MOVs utilizing dc power (see Figure A.3.b). Both MOVs are automatically signaled to open on reactor vessel low level. These valves may also be opened or closed by remote manual switches (see Table A.3.4).

No information has been found concerning the automatic closing of these two MOVs. [The steam supply line to the RCIC turbine requires containment isolation protection and thereby receives the attention in the FSAR.]

A.3.4.2 Indications of Overpressurization or Interfacing LOCA

Overpressurization of the low pressure RCIC pump suction piping would be alarmed in the control room. There is also a pressure indicator for that line in the control room. The 6" suction line is protected by a 1" relief valve set at 150 psig. The low pressure piping is bounded by the pump on one end and by closed valves to the two possible suction sources the CST (closed valve) and suppression pool (N.C. MOV). Area radiation monitoring is also available in the RCIC pump room.

A.3.5 Core Spray Injection Lines

A.3.5.1 Automatic and Manual Control

The core spray system is part of the ECCS and is not used under normal circumstances. There are two core spray lines which feed directly into the reactor. The valve lineup from the vessel outwards includes an air operated check valve inside the drywell, a normally closed MOV and then a normally open MOV both outside the drywell (see Figure A.3.c). Both MOVs receive automatic open signals upon either low-low reactor water level or high drywell pressure, however, these isolation valves are interlocked so that they can not be opened (if closed) unless vessel pressure is below approximately 350 psi. Both sets of valves can be manually controlled from the control room (see Table A.3.6).

A.3.5.2 Indications of Overpressurization or Interfacing LOCA

There is a pressure sensor upstream of the inboard isolation valve (MOV 25A, B) which is set to provide an alarm on high pressure and there is a 2" relief valve set at 475 psig upstream of the outboard isolation valve. The vulnerable piping is from the upstream isolation valve (MOV 24A, B) back through to the pump discharge stop check valves (8A and 8B).

A.3.6 HPCI Pump Suction

A.3.6.1 Automatic and Manual Control

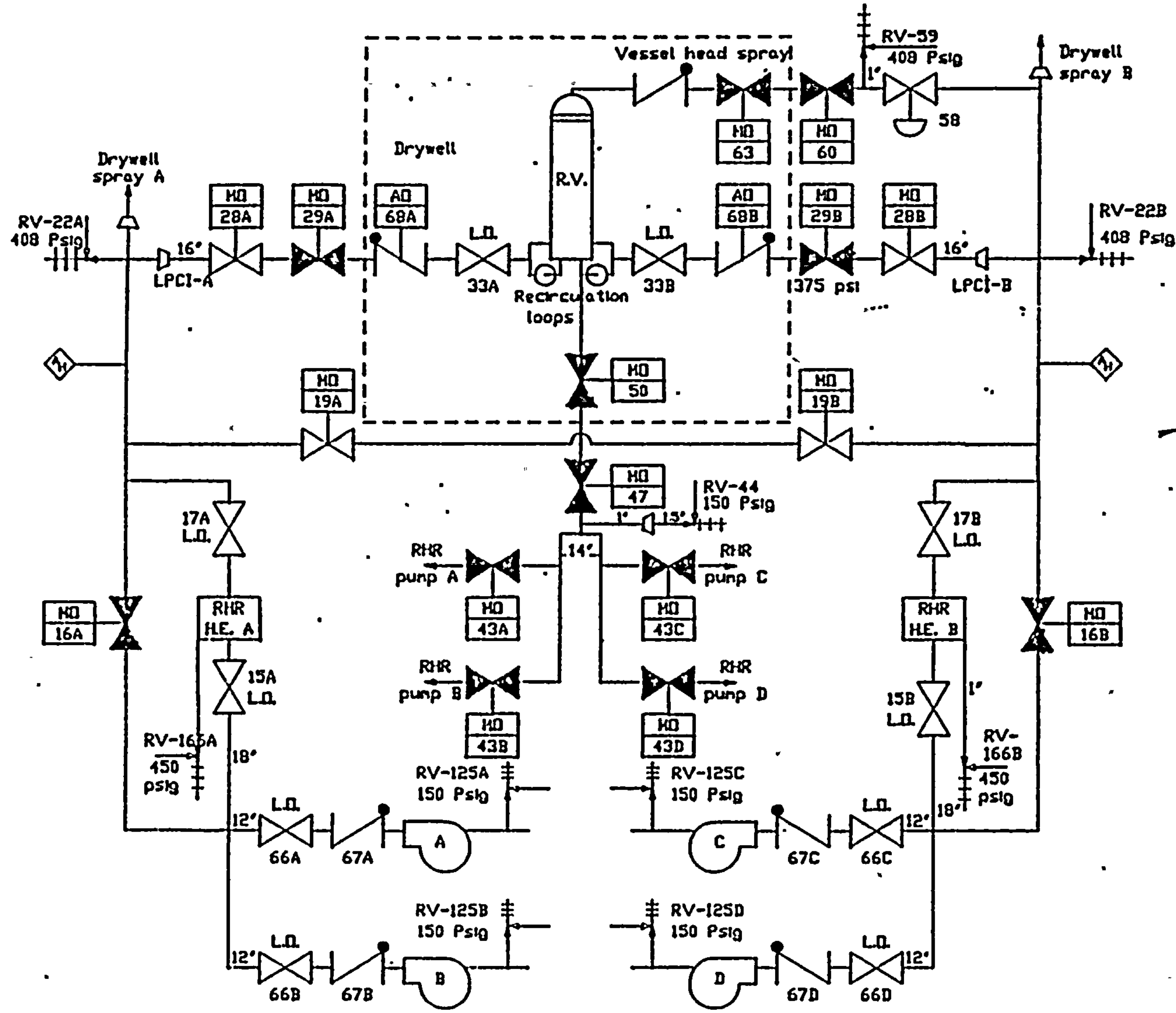
The HPCI injection line feeds into the feedwater line upstream of that lines containment isolation valves. Therefore, in order to have an interfacing system LOCA, the two normally open (during operation) feedwater isolation valves (check valves) must fail to close in addition to the overpressurization failure of the HPCI system (see Table A.3.8). The HPCI valve lineup from the feedwater line to the pump consists of an air operated check valve, a normally closed MOV and a normally open MOV (see Figure A.3.d). Both MOVs are automatically signaled to open upon reactor vessel low level or high drywell pressure. The normally closed inboard isolation valve is also automatically signaled to close signaled to trip (see Table A.3.7). Automatic tripping of the HPCI turbine

occurs when either of two high turbine exhaust pressure switches are actuated, or two reactor high water level switches are both actuated, or on low HPCI pump section pressure, however, these tripping mechanisms are only active when the turbine stop valve is open (i.e., the pump is operating).

The HPCI injection line has undergone a recent design modification in which a new safe shutdown system had been added. The safe shutdown system consists of one motor-operated pump and functions in a similar manner to the RCIC. The one pump is capable of injecting into either units' HPCI injection line upstream of the HPCI air-operated check valve (see Figure A.3.d). The system configuration from the pump consists of a discharge check valve and a normally closed motor operated globe valve, then the line splits into two lines (one to each unit) and these two lines each have a normally closed gate valve and a check valve. This configuration yields seven high pressure valves and piping between the low pressure pump suction and the reactor coolant system of either unit. Therefore, this line has not been analyzed further with respect to interfacing system LOCA.

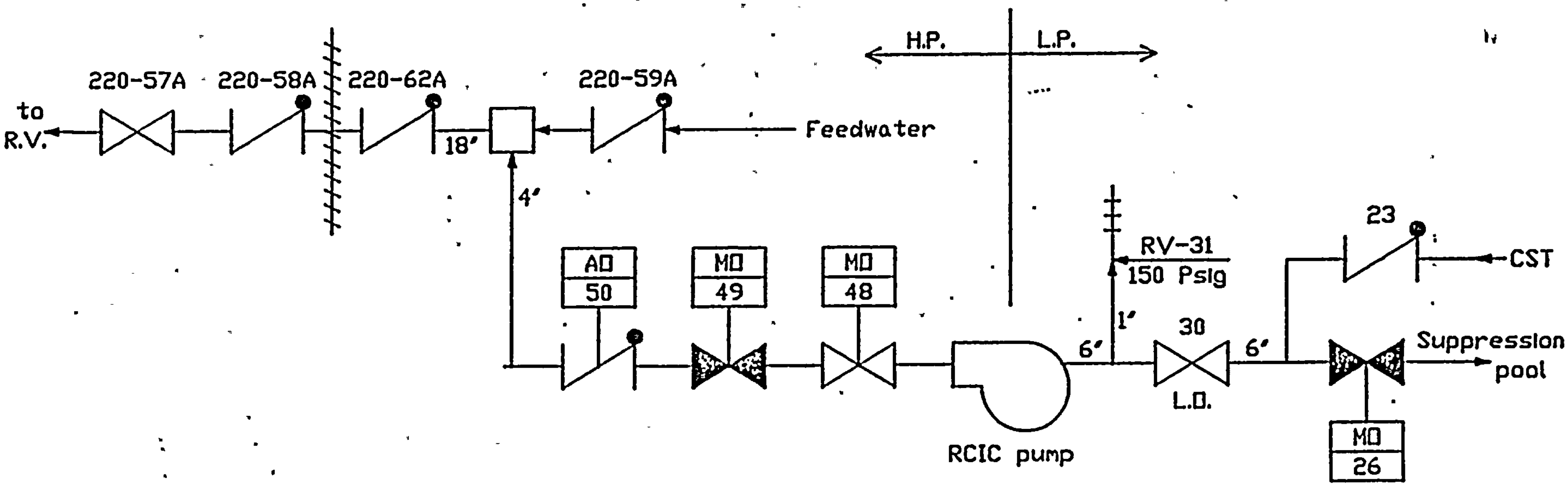
A.3.6.2 Indication of Overpressurization or Interfacing LOCA

There are two pressure indicators in the control room, one for pump suction and one for pump discharge. There is a separate pressure sensor on the suction piping which alarms in the control room. It is the low pressure suction piping that is at risk and it is protected by a 1.5" relief valve set at 150 psig. The low pressure piping is bounded by the pump on one end and by closed valves in the two possible suction source lines in the CST (check valve) and the suppression pool (N.C. MOV). There are four sets of four high temperature sensors connected in one-out-of-two-twice logic for monitoring HPCI steam line leaks/breaks. This would alarm to the operator. There is also area radiation monitoring availabe in the HPCI pump room.



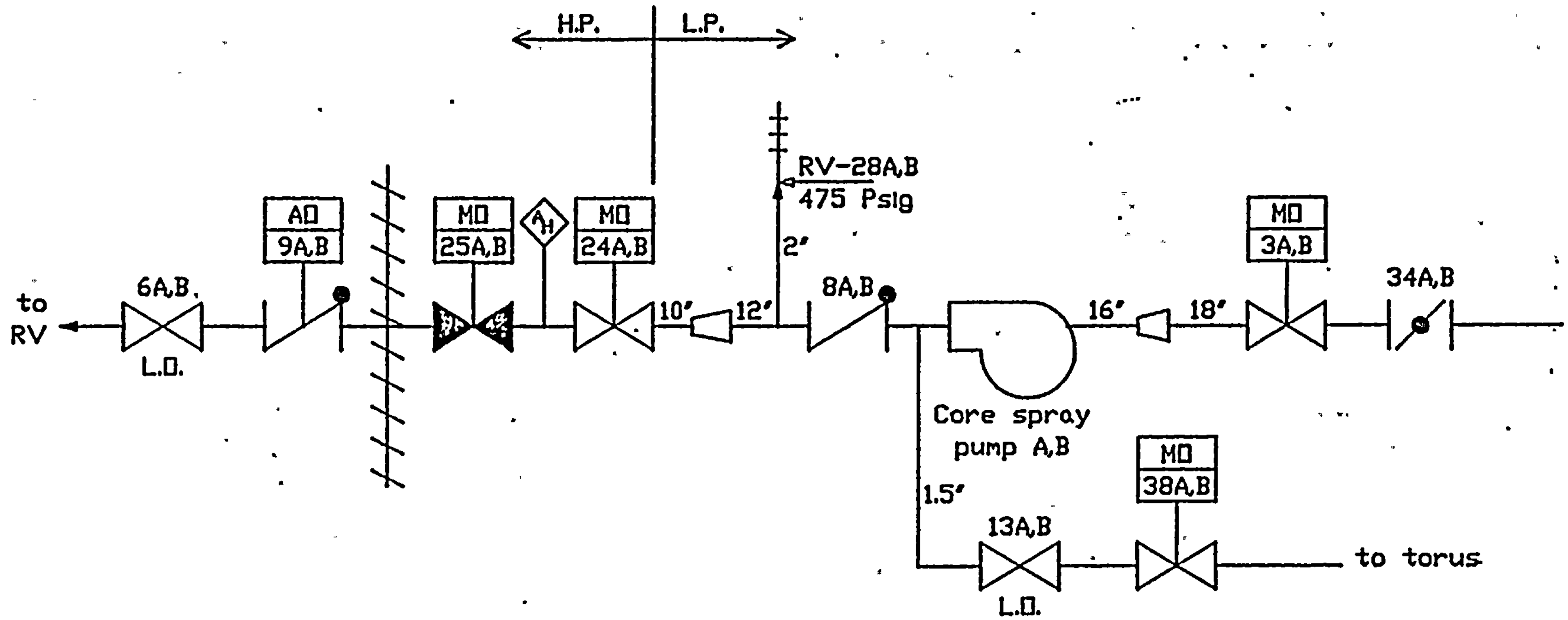
Note: All equipment have the following prefix 1001-.

Figure A.3a Residual heat removal system.



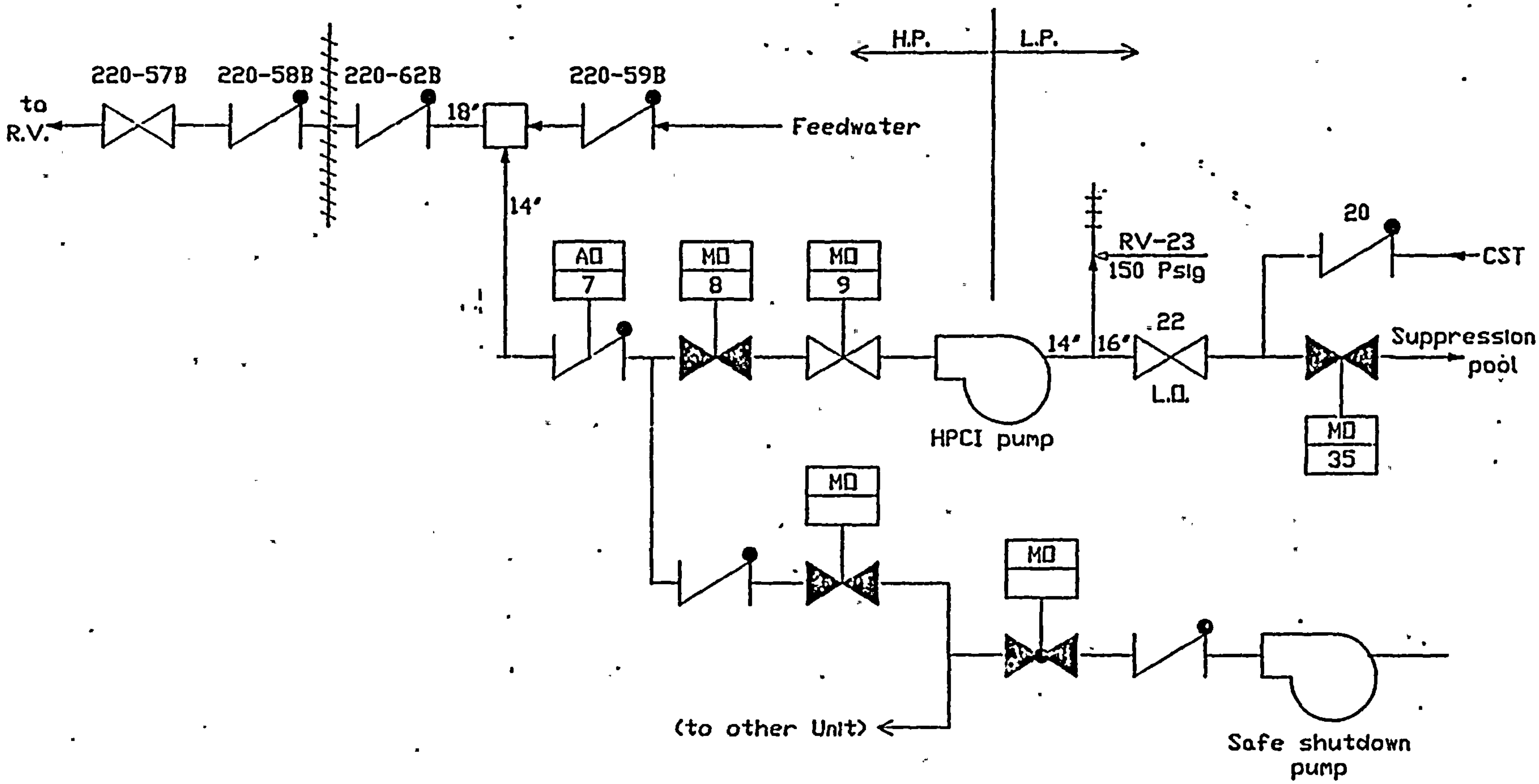
Note: All equipment has the following prefix, 1301, if other prefix is not shown.

Figure A.3b RCIC system.



Note: All equipment has the following prefix, 2301, if other prefix not shown.

Figure A.3c LPCS system.



Note: All equipment have the following prefix 2301- (if other prefix not shown).

Figure A.3d HPCI system.

Table A.3.1
Shutdown Cooling Supply (RHR)

1.	Number of lines -	1	
2.	Line size -	20"	
3.	Valve number -	1001-47*	1001-50*
4.	Valve location -	Outside	Inside
5.	Valve type -	MO gate	MO gate
6.	Valve operator -	dc	ac
7.	Valve normal position -	Closed	Closed
8.	Power failure position -	Closed	Closed
9.	Isolation signals -	A,U,$\overline{M}$**	A,U,$\overline{M}$**
10.	Normal flow direction -	out	out
11.	Surveillance requirement -	CI	CI
12.	Pump surveillance requirement -	N/A to this mode of operation	
13.	Relief capacity & setpoint -	RV-44 1.5" @ 150 psig	

*Interlocked to prevent opening with primary pressure $\geq$ 100 psig.
**See Table A.3.10.
CI:LLRT and position indication once per operating cycle; stroked at each cold shutdown.

Table A.3.2
Reactor Head Spray (RHR)

1.	Number of lines -	1		
2.	Line size -	4"		
3.	Valve number -	1001-64	1001-63*	1001-60*
4.	Valve location -	Inside	Inside	Outside
5.	Valve type -	Check	MO gate	MO gate
6.	Valve operator -	----	ac	dc
7.	Valve normal position -	Closed	Closed	Closed
8.	Power failure position -		Closed	Closed
9.	Isolation signals -	---- **	A,U	A,U
10.	Normal flow direction -	In	In	In
11.	Surveillance requirement -	None	CI	CI
12.	Pump surveillance requirement -	N/A to this mode of operation		
13.	Relief capacity & setpoint -	RV-59 1" @ 408 psig	RV-22A&B 1" @ 408 psig	RV-166A&B 1" @ 450 psig

*Interlocked to prevent opening with primary pressure $\geq$ 100 psig.
**See Table A.3.10.
CI:LLRT and position indication once per operating cycle; stroked at each cold shutdown.

Table A.3.3
LPCI to Reactor (RHR)

1.	Number of lines -	2		
2.	Line size -	16 in.		
3.	Valve number -	1001-68A,B	1001-29A,B*	1001-28A,B
4.	Valve location -	Inside	Outside	Outside
5.	Valve type -	AO check	MO gate	MO globe
6.	Valve operator -	air	ac	ac
7.	Valve normal position -	Closed	Closed	Open
8.	Power failure position -	/	Closed	Open
9.	Isolation signals -	--- **	RM,H,$\overline{V}$	RM,H,$\overline{V}$
10.	Normal flow direction -	In	In	In
11.	Surveillance requirement -	R	SAA/MO/C	SAA/MO
12.	Pump surveillance requirement -	SAA/FRT/PO		
13.	Relief capacity & setpoint -	RV-22A,B 1" @ 408 psig	RV-59 1" @ 408 psig	RV-166A&B 1" @ 450 psig

*Interlocked to prevent opening with primary pressure $\geq$ 375 psig.
**See Table A.3.10.
SAA: Simulated Automatic Actuation - each refueling.
FRT: Flow Rate Test - after pump maintenance and every 3 months.
PO: Pump operability - once per month.
MO: MOV operability - once per month; position indication at refueling.
R: Stroked at refueling.
C: LLRT at refueling.

Table A.3.4
RCIC Injection Line*

1.	Number of lines -	1		
2.	Line size -	6" (pump suction)		
3.	Valve number -	1301-50	1301-49	1301-48
4.	Valve location -	Out	Out	Out
5.	Valve type -	AO check	MO gate	MO gate
6.	Valve operator -	air	dc	dc
7.	Valve normal position -	Closed	Closed	Open
8.	Power failure position -		Closed	Open
9.	Isolation signals -			
10.	Normal flow direction -	In	In	In
11.	Surveillance requirement -	MO	SAA/MO	SAA/MO
12.	Pump surveillance requirement -	SAA/FRT/PO		
13.	Relief capacity & setpoint -	1 @ RCIC pump suction (RV-31) 1" @ 150 psig		

*RCIC injection line connects to the feedwater system piping outside the drywell. In order to have an interfacing systems LOCA the valves in Table A.3.5 must also fail.

SAA: Simulated Automatic Actuation - each refueling.
FRT: Flow Rate Test - after pump maintenance and every 3 months.
PO: Pump operability - once per month.
MO: MOV operability - once per month.

Table A.3.5
Feedwater Connection from RCIC to RPV

1.	Number of lines -	1	
2.	Line size -	18"	
3.	Valve number -	220-58A	220-62A
4.	Valve location -	Inside	Outside
5.	Valve type -	check	check
6.	Valve operator -		
7.	Valve normal position -	Closed	Closed
8.	Power failure position -	—	—
9.	Isolation signals -		
10.	Normal flow direction -	In	In
11.	Surveillance requirement -	C	C
12.	Pump surveillance requirement -	N/A	N/A
13.	Relief capacity & setpoint -	None	

C: LLRT at refueling.

Table A.3.6
Core Spray to Reactor

1.	Number of lines –	2		
2.	Line size –	10" from RPV thru CI valves, then 12" to pump		
3.	Valve number –	1402-9A,B	1402-25A,B	1402-24A,B
4.	Valve location –	Inside	Outside	Outside
5.	Valve type –	AO check	MO gate	MO gate
6.	Valve operator –	air	ac	ac
7.	Valve normal position –	Closed	Closed	Open
8.	Power failure position –	——	Closed	Open
9.	Isolation signals –	——*	RM,$\overline{V}$	RM,$\overline{V}$
10.	Normal flow direction –	In	In	In
11.	Surveillance requirement –	R	SAA/MO	SAA/MO
12.	Pump surveillance requirement –	SAA/FRT/PO		
13.	Relief capacity & setpoint –	RV-28A,B 2" @ 475 psig		

SAA: Simulated Automatic Actuation – each refueling.
FRT: Flow Rate Test – after pump maintenance and every 3 months.
PO: Pump operability – once per month.
MO: MOV operability – once per month.
R: Stroke at refueling.
* See table A.3.10.

Table A.3.7
HPCI Injection Line*

1.	Number of lines –	1		
2.	Line size –	14" (pump discharge), 16" (pump suction)		
3.	Valve number –	2301-7	2301-8	2301-9
4.	Valve location –	Out	Out	Out
5.	Valve type –	AO check	MO gate	MO gate
6.	Valve operator –	air	dc	dc
7.	Valve normal position –	Closed	Closed	Open
8.	Power failure position –	——	Closed	Open
9.	Isolation signals –	——	HPCI turbine trip	——
10.	Normal flow direction –	In	In	In
11.	Surveillance requirement –	S	SAA/MO	SAA/MO
12.	Pump surveillance requirement –	SAA/FRT/PO		
13.	Relief capacity & setpoint –	1 @ HPCI pump suction (RV-23) 1.5" @ 150 psig		

*HPCI injection line connects to the feedwater system piping outside the drywell. In order to have an interfacing system LOCA the valves in Table A.3.8 must also fail.

SAA: Simulated Automatic Actuation – each refueling.
FRT: Flow Rate Test – after pump maintenance and every 3 months.
PO: Pump operability – once per month.
MO: MOV operability – once per month.
S: Stroke every cold shutdown (need not be more frequent than once per 90 days).

Table A.3.8
Feedwater Connection from HPCI to RPV

1.	Number of lines -	1	
2.	Line size -	18"	
3.	Valve number -	220-58B	220-62B
4.	Valve location -	Inside	Outside
5.	Valve type -	check	check
6.	Valve operator -		
7.	Valve normal position -	Closed	Closed
8.	Power failure position -	----	----
9.	Isolation signals -		
10.	Normal flow direction -	In	In
11.	Surveillance requirement -	C	C
12.	Pump surveillance requirement -	N/A	N/A
13.	Relief capacity & setpoint -	None	

C: LLRT at refueling.

Table A.3.9
Screening of Lines Penetrating Containment for Interfacing Lines at Quad Cities

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

	Valve Part Number	Line Isolated	Drywell Penetration Number[1]	Valve Type	Class[2]	Location Ref to Drywell	Normal Status	Isolation Signal	Power to Close	Power to Open
A	203-1 A, B, C, D	Main steam line	X-7	AO Globe	A	Inside	Open	B, C, D, P	air & spring	air & ac, dc
A	203-2 A, B, C, D	Main steam line	X-7	AO Globe	A	Outside	Open	B, C, D, P	air & spring	air & ac, dc
A	220-1	Main steam line drain	X-8	MO Gate	A	Inside	Closed	B, C, D, P	ac	ac
A	220-2	Main steam line drain	X-8	MO Gate	A	Outside	Closed	B, C, D, P	dc	dc
*	220-59 A, B	From reactor feedwater	X-9	Check	A-X	Outside	Open	Rev. flow	Process	-
*	220-58 A, B	From reactor feedwater	X-9	Check	A-X	Inside	Open	Rev. flow	Process	-
B	220-44	Reactor water sample	X-41	SO Valve	A	Inside	Closed	B, C, D, P	Spring	ac
B	220-45	Reactor water sample	X-41	SO Valve	A	Outside	Closed	B, C, D, P	Spring	ac
C	301-95	Control rod hydraulic ret	X-36	Check	A-X	Outside	Opens on rod move- ment & closed at all other times -	Rev. flow	Process	-
C	301-98	Control rod hydraulic ret	X-36	Check	A-X	Inside		Rev. flow	Process	-
B	SO-120	Control rod drive exhaust	None	SO Valve	A-X	Outside		None - see Normal Status	Spring	ac
B	SO-121	Control rod drive exhaust	None	SO Valve	A-X	Outside			Spring	ac
B	SO-122	Control rod drive inlet	None	SO Valve	A-X	Outside			Spring	ac
B	SO-123	Control rod drive inlet	None	SO Valve	A-X	Outside			Spring	ac
*	1001-47	RHR Reactor shutdown cooling supply	X-12	MO Gate	A	Outside	Closed	A, U, M	dc	dc
*	1001-50	RHR Reactor shutdown cooling supply	X-12	MO Gate	A	Inside	Closed	A, U, M	ac	ac
E	1001-37 A, B	RHR to suppression spray header	X-211	MO Globe	B-X	Outside	Closed	G, S	ac	ac
E	1001-26 A, B	RHR - containment spray	X-39	MO Gate	B-X	Outside	Closed	G, S	ac	ac
E	1001-23 A, B	RHR - containment spray	X-39	MO Gate	B-X	Outside	Closed	G, S	ac	ac
*	1001-63	RHR - reactor head spray	X-17	MO Gate	A	Inside	Closed	A, U	ac	ac
*	1001-60	RHR - reactor head spray	X-17	MO Gate	A	Outside	Closed	A, U	dc	dc
E	1001-36 A, B	RHR test line to suppression pool	X-210	MO Globe	B-X	Outside	Closed	G	ac	ac
E	1001-34 A, B	RHR - suppression pool test return	X-211	MO Gate	B-X	Outside	Closed	G	ac	ac
*	1001-29 A, B	RHR - LPCI to reactor	X-13	MO Gate	A-X	Outside	Closed	RM, H, V	ac	ac
*	1001-28 A, B	RHR - LPCI to reactor	X-13	MO Globe	A-X	Outside	Open	RM, H, V	ac	ac

Table A.3.9 (Continued)

	Valve Part Number	Line Isolated	Drywell Penetration Number[1]	Valve Type	Class[2]	Location Ref to Drywell	Normal Status	Isolation Signal	Power to Close	Power to Open
*	1001-68 A, B	RHR - LPCI to reactor	X-13	AO Check	A-X	Inside	Closed		Note (3)	(3)
E	1001-7 A, B, C, D	RHR pump suction	X-204	MO Gate	B-X	Outside	Open	RM, G	ac	ac
E	1001-20	RHR to radwaste	-	MO Gate	A	Outside	Closed	A, U	ac	ac
E	1001-21	RHR to radwaste	-	MO Gate	A	Outside	Closed	A, U	dc	dc
B	1101-16	Standby liquid control	X-110	Check	A-X	Outside	Closed	Rev. flow	Process	-
B	1101-15	Standby liquid control	X-110	Check	A-X	Inside	Closed	Rev. flow	Process	-
A	1201-2	Reactor water cleanup supply	X-14	MO Gate	A	Inside	Open	A, W, Y, J, RM	ac	ac
A	1201-5	Reactor water cleanup supply	X-14	MO Gate	A	Outside	Open	A, W, Y, J, RM	dc	dc
A	1201-80	Reactor water cleanup ret	X-15	MO Globe	A	Outside	Open	A, W, Y, J, RM	ac	ac
A	1201-81	Reactor water cleanup ret	X-15	Check	A-X	Inside	Open	Rev. flow	Process	-
A	1301-16	RCIC - turbine steam supply	X-10	MO Gate	A-X	Inside	Open	K, B	ac	ac
A	1301-17	RCIC - turbine steam supply	X-10	MO Gate	A-X	Outside	Open	K, B	dc	dc
E	1301-41	RCIC - turbine exhaust	X-212	Check	B-X	Outside	Closed	Rev. flow	Process	fwd flow
E	1301-64	RCIC - turbine exhaust	X-212	Stop Check	B-X	Outside	Closed	Rev. flow	Process	fwd flow
E	1301-55	RCIC - vacuum pump discharge to suppression chamber	X-222	Stop Check	B-X	Outside	Closed	Rev. flow	Process	fwd flow
E	1301-40	RCIC - vacuum pump discharge to suppression chamber	X-222	Check	B-X	Outside	Closed	Rev. flow	-	-
E	1301-12, 13	RCIC - steam line drain	None	AO Globe	B-X	Outside	Open	B	Spring	air/dc
E	1301-34, 35	RCIC - steam line drain	None	AO Globe	B-X	Outside	Open	B	Spring	air/dc
E	1301-25	RCIC - pump suction from suppression chamber	X-227	MO Gate	B-X	Outside	Closed	RM	dc	dc
E	1301-27	RCIC - pump suction from suppression chamber	X-227	Check	B-X	Outside	Closed	Rev. flow	-	-

Table A.3.9 (Continued)

	Valve Part Number	Line Isolated	Drywell[1] Penetration Number	Valve Type	Class[2]	Location Ref to Drywell	Normal Status	Isolation Signal	Power to Close	Power to Open
*	1400-24 A, B	Core spray to reactor	X-16	MO Gate	A-X	Outside	Open	RM, V	ac	ac
*	1400-25 A, B	Core spray to reactor	X-16	MO Gate	A-X	Outside	Closed	RM, V	ac	ac
*	1400-9 A, B	Core spray to reactor	X-16	AO Check	A-X	Inside	Closed		Note (3)	(3)
E	1400-4 A, B	Core spray test to suppression pool	X-210	MO Globe	B	Outside	Closed	G	ac	ac
E	1400-3 A, B	Core spray pump suction	X-204	MO Gate	B-X	Outside	Open	RM, G	ac	ac
E	2001-3	Drywell equipment drain discharge	X-19	AO Gate	B	Outside	Open	A, F	Spring	air/ac
E	2001-4	Drywell equipment drain discharge	X-19	AO Gate	B	Outside	Open	A, F	Spring	air/ac
E	2001-15	Drywell floor drain discharge	X-18	AO Gate	B	Outside	Open	A, F	Spring	air/ac
E	2001-16	Drywell floor drain discharge	X-18	AO Gate	B	Outside	Open	A, F	Spring	air/ac
A	2301-4	HPCI - turbine steam	X-11	MO Gate	A-X	Inside	Open	L, RM, G	ac	ac
A	2301-5	HPCI - turbine steam	X-11	MO Gate	A-X	Outside	Open	L, RM, G	dc	dc
E E E E	2301-29 2301-30 2301-64 2301-65	HPCI - steam line drains	None	AO Globe	A-X	Outside	Open	G	Spring	air/dc
E	2301-45	HPCI - turbine exhaust	X-220	Check	B-X	Outside	Closed	Rev. flow	Process	fwd flow
E	2301-74	HPCI - turbine exhaust	X-220	Stop Check	B-X	Outside	Closed	Rev. flow	Process	fwd flow
E	2301-36	HPCI pump suction from suppression chamber	X-225	MO Gate	B-X	Outside	Closed	RM, L	dc	dc
E	2301-39	HPCI pump suction from suppression chamber	X-225	Check	B-X	Outside	-	Rev. flow	Process	fwd flow
E	2301-71	HPCI turbine exhaust drain	X-221	Stop Check	B-X	Outside	Closed	Rev. flow	Process	fwd flow
E	2301-34	HPCI turbine exhaust drain	X-221	Check	B-X	Outside		Rev. flow	Process	fwd flow
B	700-736	Traversing in-core probe	X-35	Squib Shear	A-X	Outside	Open	RM	dc	dc
B	700-733	Traversing in-core probe	X-35	SO Ball	A-X	Outside	Closed	AF	ac	ac

Table A.3.9 (Continued)

	Valve Part Number	Line Isolated	Drywell[1] Penetration Number	Valve Type	Class[2]	Location Ref to Drywell	Normal Status	Isolation Signal	Power to Close	Power to Open
B	220-18 A	Instrument sensing line	X-29, -50	Hand Globe	A-X	Outside	Open		Hand	Hand
B	220-12 A	Steam flow measurement	X-29, -50	Flow Check	A-X	Outside	Open	Rev. flow	Hand	Spring
E	1001-38 A	Instrument sensing drywell pressure	X-32	Hand Globe	B-X	Outside	Open	Rev. flow	Hand	Hand
E	By AE	Service air to drywell	X-21	Check	B	Outside	Closed	Rev. flow	Spring	-
E	By AE	Service air to drywell	X-21	AO Globe	B	Outside	Closed	RM	Spring	air
E	By AE	Instrument air to drywell	X-22	Check	B	Outside	Open	Rev. flow	Spring	-
E	By AE	Instrument air to drywell	X-22	AO Globe	B	Outside	Open	RM	Spring	air
E	By AE	Reactor building close cooling water in	X-23	Check	C-X	Outside	Open	Rev. flow	Process	-
E	By AE	Reactor building close cooling water out	X-24	MO Gate	C-X	Outside	Open	RM	ac	ac
E	By AE	Service water in	X-20	Check	C-X	Outside	-	Rev. flow	Process	-
E	1601-20 A, B	Vacuum breaker sec. cont. to suppression	X-205	Check	B	Outside	-		Suppression pool pressure	-
E	1601-33	Vacuum breaker suppression to drywell	X-202	Vac Bkr	B	Inside suppression chamber	-	-	Drywell pressure	-
E	1601-32	Vacuum breaker suppression to drywell	X-202	Vac Bkr	B		-	-	Drywell pressure	-
E	1601-21, -22	Drywell purge inlet	X-26	AO Butterfly	B	Outside	Closed	FA	Spring	air/ac
E	1601-23	Drywell main exhaust	X-25	AO Butterfly	B-X	Outside	Closed	FA	Spring	air/ac
E	1601-61	Suppression chamber exhaust valve bypass	X-203	AO Gate	B-X	Outside	Closed	FA	Spring	air/ac
E	1601-56	Suppression chamber purge inlet	X-205	AO Butterfly	B-X	Outside	Closed	FA	Spring	air/ac
E	1601-60	Suppression chamber main exhaust	X-203	AO Butterfly	B-X	Outside	Closed	FA	Spring	air/ac
E	1601-24	Main primary containment exhaust	X-202 X-25	AO Butterfly	B-X	Outside	Closed	FA	Spring	air/ac

Table A.3.10
Key to the Isolation Signal Codes in the Tables

Signal Code	Description
A	Reactor low water level "A" - scram and close isolation valves except main steam lines.
B	Reactor low water level "B" - initiate RCIC and close main steam line isolation valves.
(B)	Valve opens on signal "B".
C	High radiation - main steam line.
D	Line break - main steam line (steam line high space temperature or excess steam flow).
F	High drywell pressure - close drywell atmospheric control and secondary containment isolation valves, scram reactor.
G	Reactor low water level "G" or high drywell pressure - initiate core spray, RHR, and HPCI systems.
(G)	Valve opens on signal "G". Signal "L" overrides signal (G).
H	Line break in recirculation loop - close corresponding RHR-LPCI loop valves and open valves in opposite loop.
(J)	Line break in cleanup system - high space temperature; alarm only; no auto closure.
K	Line break in RCIC system steam line to turbine (high steam line space temperature or excess steam (low or low steam line pressure) - overrides signal B.
L	Line break in HPCI system steam line to turbine (high steam line space temperature or excess steam (low or low steam line pressure).
(M)	Line break in RHR shutdown and head cooling (high space temperature; alarm only; no auto closure).
P	Low main steam line pressure at inlet to main turbine (run mode only).
S	Low drywell pressure - close containment spray and suppression cooling valves.
T	Low reactor pressure permissive to open core spray and RHR-LPCI valves.
U	High reactor pressure - close RHR-shutdown cooling valves and head cooling valves.
(V)	Valve opens on coincident signals "G" and "T". Signal "H" overrides signal (V).
W	High temperature at outlet of cleanup system nonregenerative heat exchanger.
Y	Standby liquid control system actuated.
Z	High radiation, process rad monitor, reactor building ventilation exhaust plenum.
RM	Remote manual switch from control room.

*Encircled letters appear with a bar over them in some of the tables.

Table A.3.10 (Continued)

Notes for Tables:

1 Basic penetration numbers are shown. Suffix letters that follow the basic number are given on the appropriate piping and instrumentation diagram.

2 Class A valves are on process lines that communicate directly with the reactor vessel and penetrate the containment.

Class B valves are on process lines that do not directly communicate with the reactor vessel, but penetrate the primary containment and communicate with the containment free space.

Class C valves are on process lines that penetrate the primary containment but do not directly communicate with the reactor vessel or with the primary containment free space and are not on lines that communicate with the environs.

A fourth class of valves are exceptions to the above definitions. Their class designations are followed by an "X" suffix; for example, A-X. These valves either can be opened after a containment signal or are opened automatically on certain containment signals to permit the operation of the control rods, the standby liquid control system and the various core and containment cooling systems.

Minimum closing rates for each isolation valve shall be:

Class A valves shall be closed prior to the start of uncovering of fuel caused by blowdown from that line. The main steam isolation valves closing time shall be adjustable between 3 and 10 seconds during specified flow and temperature.

Class B and C valves closure times shall be selected to limit radioactivity release from containment to below permissible limits in the event of a loss-of-coolant accident blowdown within the primary containment.

(The closure rates given are as required for containment isolation only—system operational requirements may be more restrictive.)

3 Testable check valves are designed for remote opening with approximately zero differential pressure across the valve seat. The valves will close on reverse flow even though the test switches may be calling for open. The valves will open when pump pressure exceeds reactor pressure even though the test switch may be calling for close.

APPENDIX B: Description of Incidents Involving Failure of Pressure Isolation Valves at BWRs

In this appendix, detailed descriptions of the incidents identified in Section 3 are provided. The valve arrangements for the interfacing lines involved are shown in Figures B.1 through B.11.

B.1 Vermont Yankee (LER 77-04)

On December 12, 1975, with the plant at 99% power, monthly operability surveillance testing was being conducted on Loop "A" LPCI injection valve V-10-25A. Initially, injection valve V-10-25A failed to respond to an open signal from its remote control switch. To determine if the motor-operated valve failure was caused by excessive differential pressure across the valve disk or a specific mechanical or electrical malfunction, plant personnel first manually cracked open V-10-25A. Then the valve was successfully cycled fully open and closed. During this time, unknown to the plant personnel, testable isolation check valve V-10-46 downstream of the injection valve was not seating properly, and the supposedly closed motor-operated valve (V-10-27A) upstream of the injection valve was partially open. With a partially open flow path between the RCS and RHR system unknowingly established, RCS water at operating pressure and temperature flowed into the low-pressure LPCI Loop "A" system piping, pressurizing it in excess of its design pressure. High pressure in the line caused a mixture of steam and water to be discharged from each of the three RHR system relief valves and the RHR heat exchanger tube sheet-to-shell flange area. The gasket in the tube sheet-to-shell flange area began leaking as a result of the elevated pressure conditions.

The exact cause for the testable isolation check valve not seating properly was not reported at the time of the event in 1975. The upstream injection valve (V-10-27A) had been closed from the control room prior to opening V-10-25A as part of the surveillance test sequence, but failed to fully shut. The partial opening of the motor-operated valve was not known by plant personnel at the time of the event due to a false closed position indication. The exact causes for the faulty position indication also were not reported at the time of the event.

Following successful pressure and operability testing of the subsystems involved in the overpressurization event, the subsystems were declared operable.

B.2 Cooper Station (LER 77-04)

On January 21, 1977, with the plant operating at 97% power, plant personnel were in the process of performing high pressure coolant injection (HPCI) system turbine trip and initiation logic surveillance testing. When the injection valve was opened, as required by the surveillance test, feedwater flowed backwards through the injection line, pressurizing the HPCI system close to operating pressure. It was not reported whether the low-pressure suction piping of the HPCI system also was pressurized in excess of its design pressure during the event.

The licensee determined that the HPCI testable check valve (AO-18), downstream of the injection valve, had been stuck open during the test allowing feedwater to backflow into the system when the injection valve was cycled open. The extent of flow through the open check valve was not known.

The testable isolation check valve was disassembled following shutdown of the reactor about two weeks later and was found to be blocked open by a 14-1/2" long sample probe which had wedged under the edge of the valve disk.

This prevented the check valve from fully closing. It was determined that the broken probe had come from a sample point on a 24" feedwater line upstream of the HPCI injection line junction. The length of time that the check valve had been stuck open was not determined.

B.3 LaSalle-1 (LER 82-115)

On October 5, 1982, with the plant operating at 20% power, quarterly surveillance testing on the high pressure core spray system (HPCS) was being conducted. The testable isolation check valve 1E22-F005 and its associated bypass valve 1E22-F354 failed to indicate completely closed after they were opened fro the test. Both the testable isolation check valve and its bypass valve are situated on the HPCS injection line inside primary containment. The

HPCS system was declared inoperable. The motor-operated HPCS injection valve was closed and deactivated.

During the surveillance test, the check valve bypass valve 1E22-F354 was first opened to equalize the pressure on both sides of the testable check valve disk. The testable check valve was then tested open by operating a remote hand switch. This hand switch energized a solenoid valve to allow instrument air to be supplied to one side of the piston cylinder of the air operator of the testable check valve, causing the piston cylinder to move a rack and gear assembly against spring tension. The rack and gear assembly movement rotated the actuator rod which lifted the valve disk off its seat. When the hand switch was returned to its closed position, the solenoid valve was de-energized, cutting off instrument air supply to the piston cylinder. This should have allowed the spring (tension) to return the rack and gear assembly to its normal position. This, in turn, should have rotated the actuator rod back to its original position, allowing the valve disk to reclose by its own weight and differential pressure.

The failure of testable check valve 1E22-F005 to reclose was investigated by the licensee and was determined to have been caused by (1) dried lubricant on the actuator piston cylinder; (2) insufficient preload on the actuator spring assembly; and (3) the stuck open testable check valve bypass valve 1E22-F354. Together, these causes prevented the piston cylinder of the check valve air operator from returning to its fully retracted position.

B.4 LaSalle-1 (LER 83-066)

On June 17, 1983, with the plant at 48% power and quarterly operating surveillance of the HPCS system in progress, HPCS testable isolation check valve 1E22-F005 and its associated bypass valve 1E22-F354 failed to indicate closed after being tested open. The HPCS system was declared inoperable and was isolated by deactivating the normally closed motor-operated HPCS injection valve.

The licensee determined that the failure of the testable isolation check valve to reclose was caused by (1) the stuck open bypass valve 1E22-F354 which

prevented a pressure differential from developing across the valve disk of the testable check valve, and (2) possibly thermal binding of the check valve disk. With respect to the latter cause, the licensee indicated that the Anchor Darling check valve and bypass valve have a tendency if tested hot to remain partially open after being cycled. The failure of the bypass valve to reclose was traced to insufficient return spring tension in the bypass valve. While shutting down the plant, both the bypass valve and the testable check valve closed without any assistance as reactor pressure and temperature decreased. Subsequent to an analysis of the event, the licensee submitted a request to conduct surveillance testing of testable check valve 1E22-E005 only during cold shutdown.

B.5 LaSalle-1 (LER 83-105)

On September 14, 1983, the plant staff was in the process of performing a routine RHR system relay logic surveillance test with the plant in cold shutdown. At the time of the test, the "B" RHR loop was lined up with both drywell spray valves 1E12-F016B and 1E12-F-17B open, the suppression pool spray valve 1E12-F027B open, the test return to the suppression pool valve 1E12-F024B open, and the "C" RHR loop injection valve 1E12-F042C open. Unaware that the LPCI loop "B" testable isolation check valve 1E12-F041B was stuck open, the plant staff opened (as required by the test precheck) the "B" RHR loop injection valve 1E12-F042B. When the injection valve was opened a rapid decrease in reactor vessel water level was observed. Water level dropped quickly from +50" to 0" causing a Group VI primary containment isolation at +12.5". The operator quickly secured the valve line-up stopping the water level decrease. Most of the water lost from the reactor vessel went to the suppression pool. while some went to the drywell.

The cause of the draindown was determined to be the stuck open testable isolation check valve 1E12-F041B on the loop "B" LPCI injection line. Thus, when the injection valve was opened during the test, an open flow path between the reactor vessel and the suppression pool and drywell was established which allowed backflow of reactor water into the drywell and torus. The isolation check valve also provides the first isolation barrier between the high-pressure RCS and the low-pressure RHR system when the plant is at power.

The testable isolation check valve was stuck open due to two causes. First, it was held open by its attached air operator as a result of a misalignment of the interfacing gears between the check valve and the air operator. The misalignment resulted from maintenance errors on the air operator that were made earlier in the outage. During the maintenance, a score mark on the spline shaft of the check valve was used instead of a timing mark for aligning the gears. This resulted in the air operator holding the check valve disk in the open position and inhibiting disk movement in the closed direction during the draindown. Additionally, the packing gland on the check valve shaft was found to be too tight, inhibiting free movement of the valve disk.

B.6 Pilgrim (LER 83-48)

On September 29, 1983, during HPCI system logic testing while the plant was at 98% power, the low-pressure suction piping of the HPCI system was overpressurized to near operating reactor pressure and temperature. The event occurred when two HPCI pump discharge motor-operated valves were simultaneously opened as a result of personnel errors. The errors consisted of conducting more than one surveillance test at the same time and not ensuring that test prerequisites and initial test conditions for all steps in the test procedures were met. The overpressurization occurred, when the pump discharge valves were opened, because the testable isolation check valve downstream of the discharge valves was also partially stuck open at the time. The overpressurization of the suction piping (which is designed for 150 psi) ruptured the gland seal condenser gasket on the HPCI turbine. This in turn caused a mixture of water and steam to spray from the condenser onto a limit switch. The water spray resulted in a 250-V dc battery ground and a large amount of water on the HPCI room floor. Smoke detector alarms also were set off by the vapors from the heated paint on the low-pressure piping. A high suction pressure alarm and a lube oil high temperature alarm were also actuated.

The exact cause for the testable check valve being partially open was not determined. There was some evidence that a rusted linkage between the valve steam and the attached air operator had contributed to the testable check valve being partially open. In the short term, the licensee repaired the linkage and returned the valve to its correct position. The licensee decided to replace the

check valve with a new design as a long term solution. To prevent a recurrence of the personnel errors, instructions for verbal communications were to be implemented at the plant.

B.7 Hatch-2 (LER 83-112)

On October 28, 1983, with the plant in cold shutdown, the testable isolation check valve on a 24" LPCI injection line of the RHR system was found open and could not be closed. It was determined that the valve was being held open by its attached air operator. The licensee's investigation revealed that the air supply line to the air operator had been connected backwards in a prior maintenance on the valve on June 7, 1983. The resultant pneumatic pressure reversal caused the air operator to hold the check valve open even though the check valve was not being tested. The mispositioned check valve was not detected for a four-month period during which the plant operated at close to full power. The failure to detect the mispositioned valve was attributed to a reversal of the electrical leads for the valve position indicator following the June 7, 1983 maintenance. This had apparently been done by plant personnel in the belief that the valve was actually closed. Inadequate post maintenance testing also contributed to the error not being detected.

During the four-month period when the testable check valve was held open, the normally closed motor-operated LPCI injection valve upstream of the check valve remained closed. As a result, inadvertent overpressurization of the LPCI/RHR system did not occur during this period.

An immediate corrective action taken by the licensee following discovery of the maintenance error was to correctly reconnect the air supply lines to the check valve air operator. This placed the check valve in its correct position. The licensee also counseled plant maintenance personnel on the importance of performing equipment maintenance correctly. For the long-term, the licensee was to consider adopting an alternative testing method for the check valve which would not require the use of the air operator.

B.8 Susquehanna 2 (LER 84-006)

On May 21, 1984, a dual indication was received on testable check valve HV-2F050B and its associated bypass valve HV-2F122B. LPCI injection valve (Anchor Darling, horizontally mounted gate valve) HV-2F015B was closed and deenergized. Later that day, RHR throttle valve HV-2F017B was closed and -2F015B was cycled in an attempt to seal -2F050B; when -2F017B was reopened the 'B' RHR primary side HX pressure was observed increasing and -2F017B was closed. Since -2F015B was deenergized, the 'B' LPCI was inoperable and an LCO was entered.

On May 24, 1984, an LLRT showed that leakage was occurring through -2F015B and the leakage was the source of pressurization in the HX. Valve -2F017B was deenergized to ensure separation between the HP and LP portions of the 'B' RHR. Loop 'B' of the LPCI remained inoperable and the reactor shutdown was commenced on May 28 in accordance with Tech Spec.

Shutdown proceeded normally until it was observed that the No. 1 turbine bypass valve would not close below the 18% open position. Shutdown was halted and control rods in Group 5 were pulled sequentially to maintain reactor pressure with the No. 1 turbine bypass valve controller at a position slightly greater than 18%. It was determined that the best means for accomplishing shutdown would be through an RPS manual scram. The plant control operator tripped the 'B' reactor FW pump and closed all inboard MSIVs at ~700 psig.

Upon disassembly and inspection of LPCI valve -2F015B it was found that the valve's disc would not center on its seat due to the dimensions of the disc guide bearing surface. This resulted in the valve's disc sitting low in the body. Due to machining tolerance during mfg the disc would not seat in the same location each time it was stroked. To stop leakage through the valve, its seat was lapped and its lower disc guide bearing surface was built up 1/4". The valve was reassembled and an LLRT and hydro were completed on June 7 and 8, respectively.

The cause of the dual indication on the testable check valve's bypass, -2F122B, was attributable to a loose diaphragm plate connector that resulted in

improper contact with the limit switches on the bypass valve. The plate connector and its set screws were tightened and the operator was reconnected.

B.9 Browns Ferry-1 (LER 84-032)

On August 14, 1984, while at 100% power and during the performance of a six-month surveillance test of the core spray system logic, the normally closed motor-operated core spray system injection valve was inadvertently opened. When the valve opened, reactor coolant at operating pressure and temperature backflowed into the low pressure core spray system pressurizing the system piping close to full reactor pressure. The backflow also heated portions of the system piping to about 400 F. A mixture of hot water and steam sprayed from the pump seal of pump "A" of Train 1 of the core spray system. A fire alarm was set off by the plant vapors from the hot piping. Thirteen workers were contaminated by the sprayed water while responding to the fire alarm. The overpressurization, which lasted about 13 minutes, was terminated when plant personnel reclosed the injection valve.

An investigation by the licensee following the event determined that the normally closed testable isolation check valve, downstream of the injection valve, had also been open during the event. With the check valve open, a flow path between the high-pressure RCS and low-pressure core spray system piping was created when the injection valve was inadvertently opened. The cause for the open testable check valve was traced to a pneumatic pressure reversal in the air actuator. The reversal was caused by an earlier maintenance error in installing a plunger with reversed air ports in the air actuator pilot solenoid valve. A review of plant maintenance records indicated that the valve likely had been held open since December, 1983. The valve misposition was not detected for the ensuing eight-month period because the valve position indications were altered following the maintenance such that the valve misposition was not evident.

A review was also conducted to determine the cause for the inadvertent injection valve opening during the surveillance test. The test procedures specified that the valve motor operator circuit breaker should be opened so that the valve would have no motive power and would remain closed during the logic

test. It was determined, however, that the licensed operator assigned to perform this step had failed to open the breaker. Thus, when test signal was applied during the logic test, the injection valve opened.

B.10 San Onofre

On November 20, 1985, at 11:30 p.m., the plant was operating at reduced power of 250 MWe due to a tube leak in the main condenser, when an alarm sounded in the control room indicating a ground was detected by the ground detector on 4160-V bus 1C. Such a condition does not interrupt power to the equipment and thus the operation of the plant equipment was routine. While the plant personnel were troubleshooting this problem, a station blackout occurred. First, at 4:51, power to bus 2C was lost. Twenty seconds later, power to bus 1C was lost. The operators manually tripped the reactor. The reactor trip initiated a turbine trip. Power from the switchyard was restored four minutes later. Feedwater pump FWS-G-3A receives its power from bus 1C, and feedwater pump FWS-G-3B receives its power from bus 1C. When power to bus 2C was interrupted, pump FWS-G-3A stopped. Its discharge check valve FWS-438 failed open. With feedwater pump FWS-G-3B still running, backflow of feedwater through pump FWS-G-3A occurred. The piping and components upstream the feedwater pump are not designed for high pressure. The tubes of the flash evaporator condenser was overpressurized and ruptured, causing the shell to rupture. The main feedwater regulation check valves FWS-345, 346, and 398, also failed open. This resulted in the blowdown of the steam generators through the ruptured flash evaporator, after feedwater pump FWS-G-3B stopped on loss of power. The discharge check valve FWS-439 of feed water pump FWS-G-3B also failed open. This resulted in backflow through the pump after it lost its power.

As a result of low steam generator level, the turbine driven auxiliary feedwater pump was started automatically. The warmup cycle takes about three minutes. During this time, no feedwater was available. This resulted in voiding of the feedwater piping between the feedwater regulation valves and the steam generators. After the warmup cycle was completed, the pump started to deliver approximately 130 gpm AFW flow to the main feedwater line. The reverse flow in the main feedwater line carried AFW to the condensate system.

After electric power was restored, the operators, following emergency procedure after reactor trip, isolated the main feedwater lines by closing MOV-20, 21, 22, FCV-456, 457, and 458. This terminated the blowdown of the steam generators, and started refilling the voided feedwater line. The motor driven auxiliary feedwater pump started automatically after power was restored. At about 5:07 a.m., a water hammer in the feedwater line to steam generator B occurred. This resulted in displacement of the feedwater piping, damage to many pipe hangers and snubbers, an 80" crack with 30% through the wall on the 1" thick feedwater piping, and leakage of the bypass check valve FWS-379. The leaking check valve FWS-379 was identified during a containment entry at 8:00 a.m. and isolation was achieved at 10:45 a.m. by closing the manual valves in the B steam generator feedwater line and the bypass line.

Throughout the incident, except the duration of station blackout, the primary coolant inventory was maintained by controlling charging and let down. Reactor coolant pumps A and C were operable to enhance heat removal through the steam generators.

The following describes the failures of the check valves:

Valve	Description	As-Found
FWS-345	MFW Reg Check SG A	Disc separated from hinge arm, disc stud broken (threaded portion).
FWS-346	MFW Reg Check SG B	Disc separated from hinge arm, disc stud deformed.
FWS-398	MFW Red Check SG C	Disc nut loose. Disc partially open. Disc Caught inside of seat ring.
FWS-438	FWP Discharge Check	Disc nut loose. Disc partially open. Disc caught on inside of seat ring.
FWS-439	FWP Discharge Check	Disc nut loose. Disc partially open. Antirotation lug lodged under hinge arm.

B.11 Pilgrim

On February 12, 1986, with the plant at 100% power, periodic RHR high system pressure alarms (greater than 400 psig) occurred and RHR system piping between valve 28B and the RHR pumps have been noticed to be warm. It was believed that this is due to back leakage of primary coolant through the inboard check valve and the 1001-28B injection valve. The design pressure alarms have been noted but not logged for several weeks. Operators vented the piping after each alarm. Several actions were taken to stop the leakage. The MOV 28B was manually tightened. The torque switch on the valve was found set too low for complete closure. It was replaced and reset. The normally open MOV-29B was closed. The plant operation was continued. On April 11, 1986 with the reactor at 94% power, leakage through MOVs 28B and 29B occurred and resulted in high pressure alarm in the LPCI line. The first alarm was at 1415. Operators bled off the line to the normal 125 psig pressure. Pressure increased to the 400 psig alarm in 2 hours. The plant was shutdown in 24 hours.

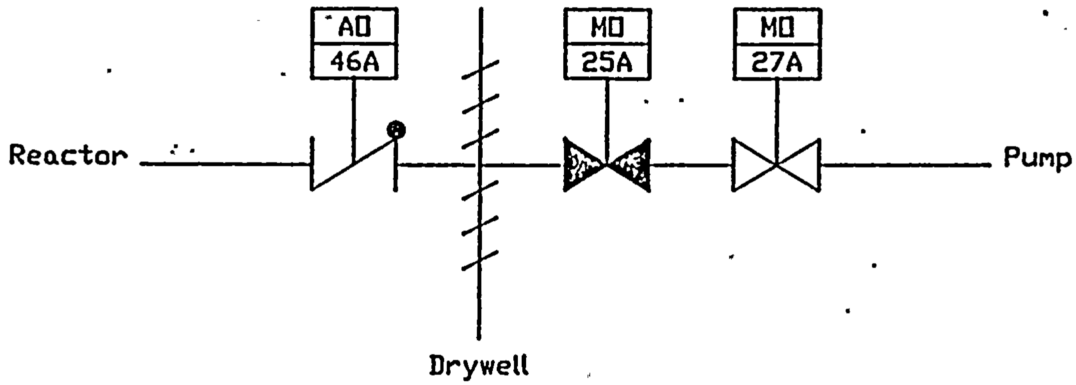


Figure B.1 Valve arrangement for LPCI injection line at Vermont Yankee on 12/12/75.

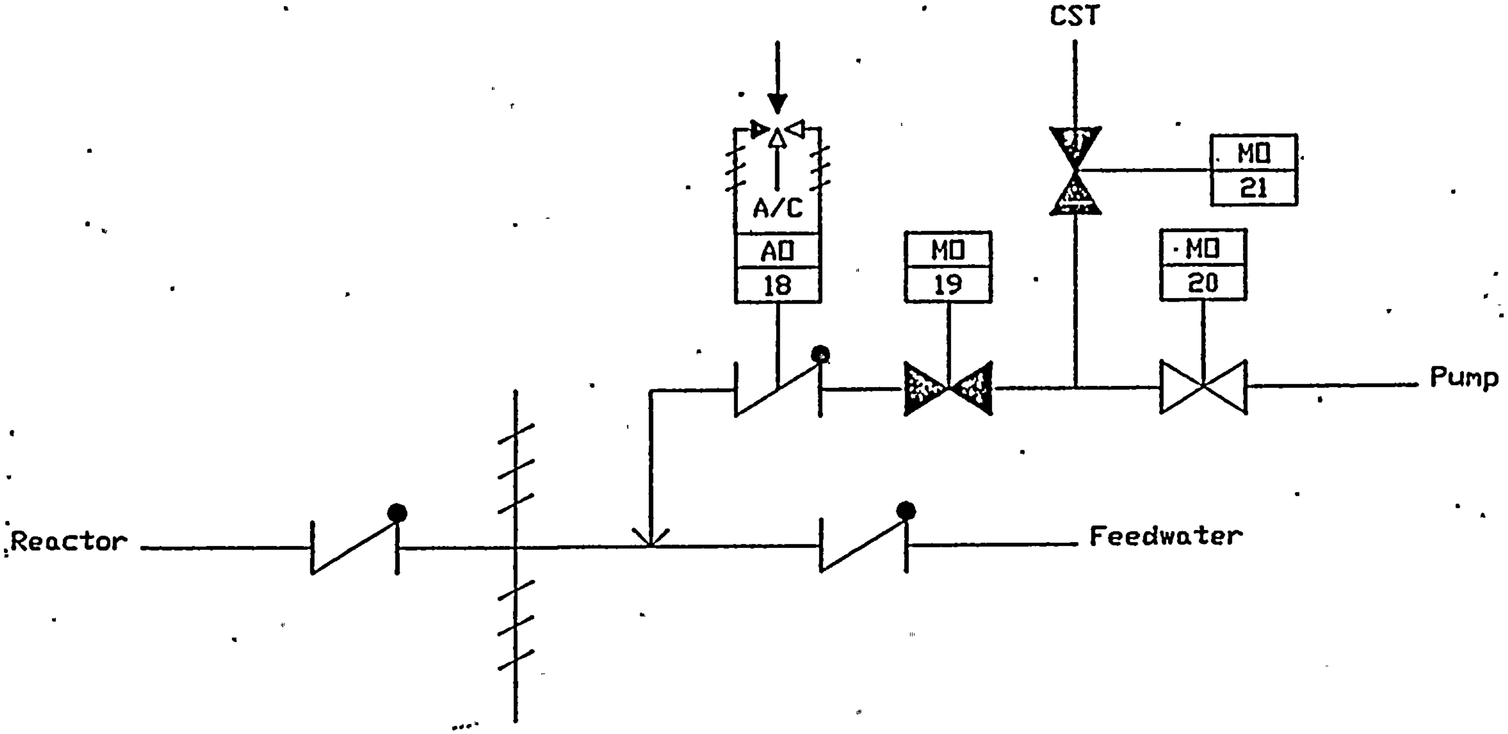


Figure B.2 Valve arrangement for HPCI injection line at Cooper on 1/21/77.

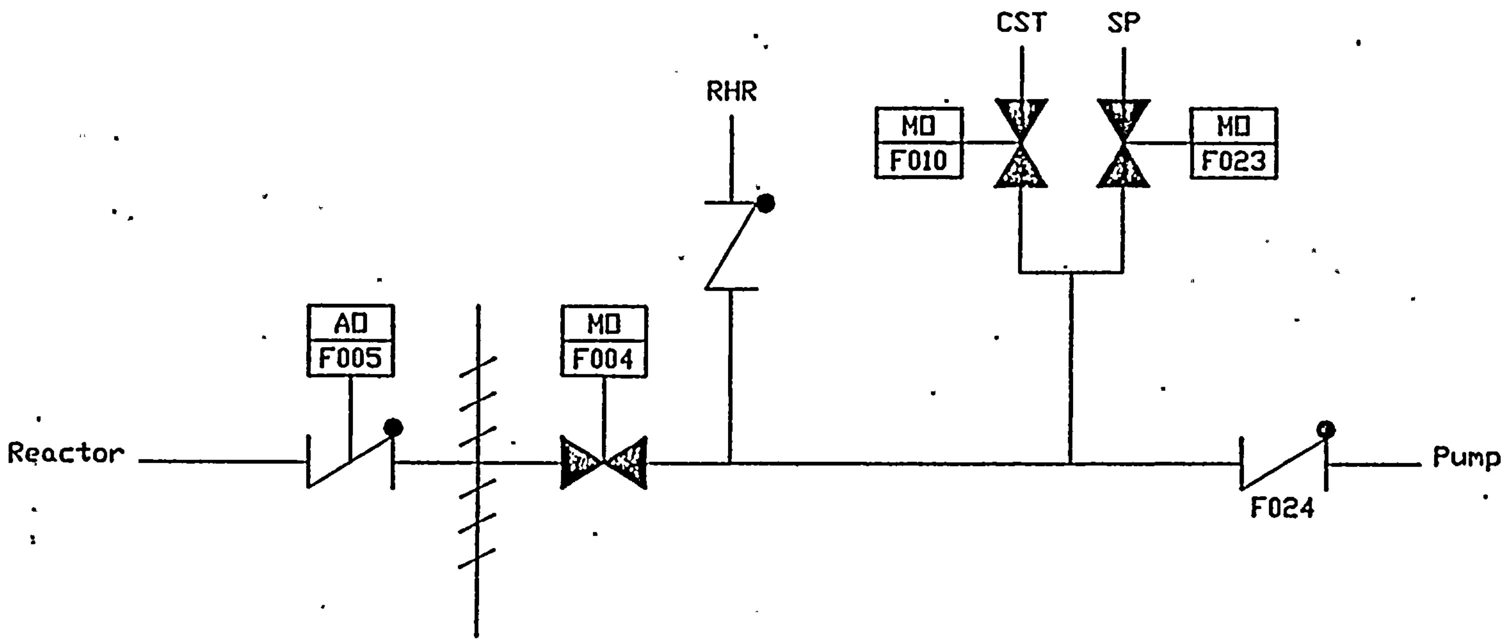


Figure B.3 Valve arrangement for HPCS injection line at LaSalle-1 on 10/5/82 and 6/17/83.

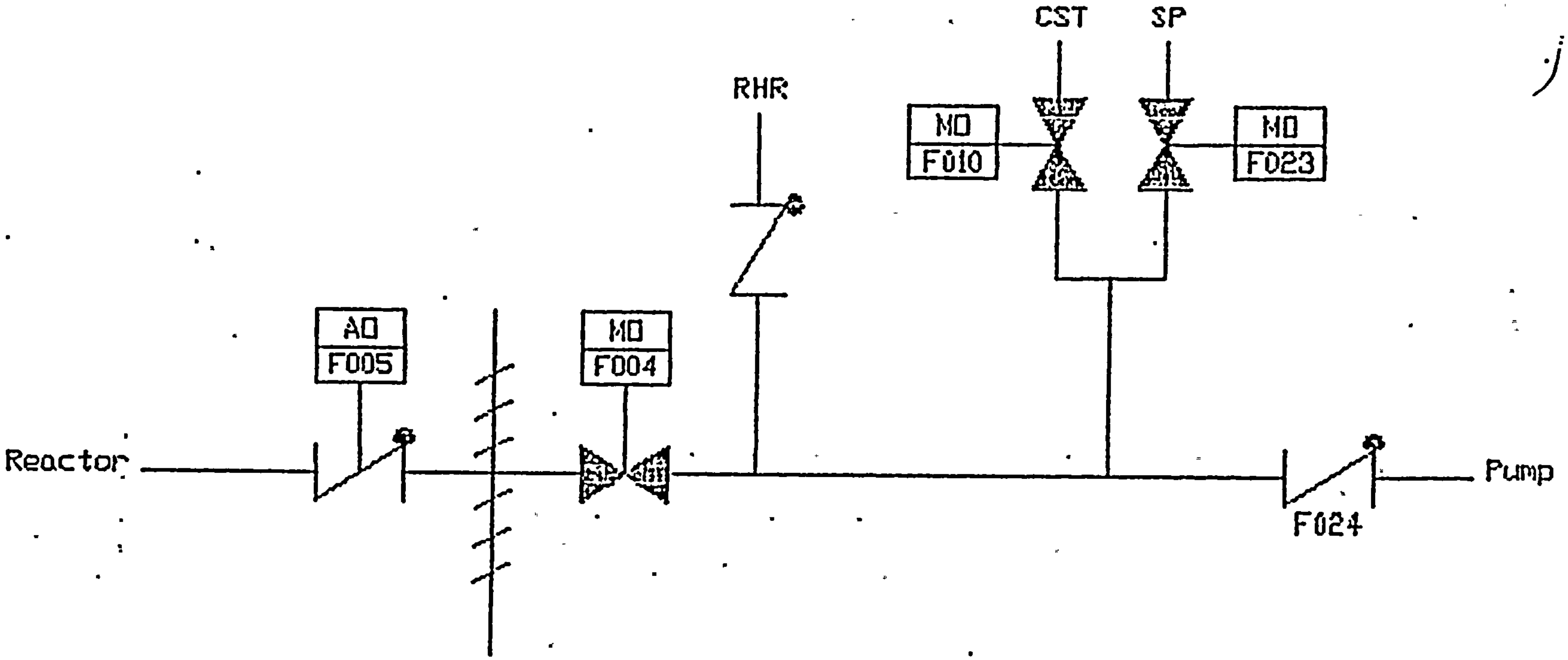


Figure B.4 Valve arrangement for HPCS injection line at LaSalle-1 on October 5, 1982 and June 17, 1983.

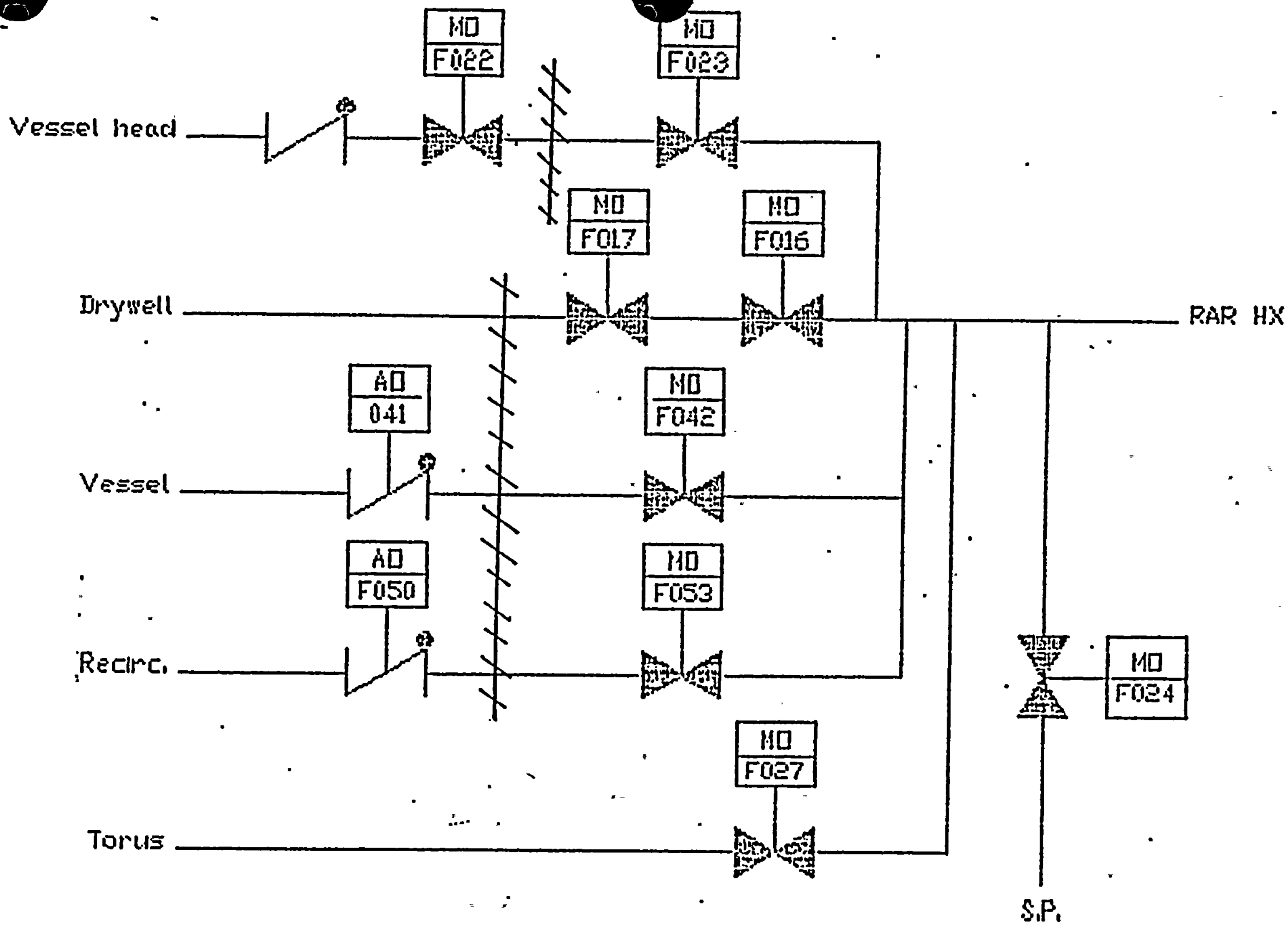


Figure B.5 Valve arrangement for LPCI injection line at LaSalle-1 on September 14, 1983.

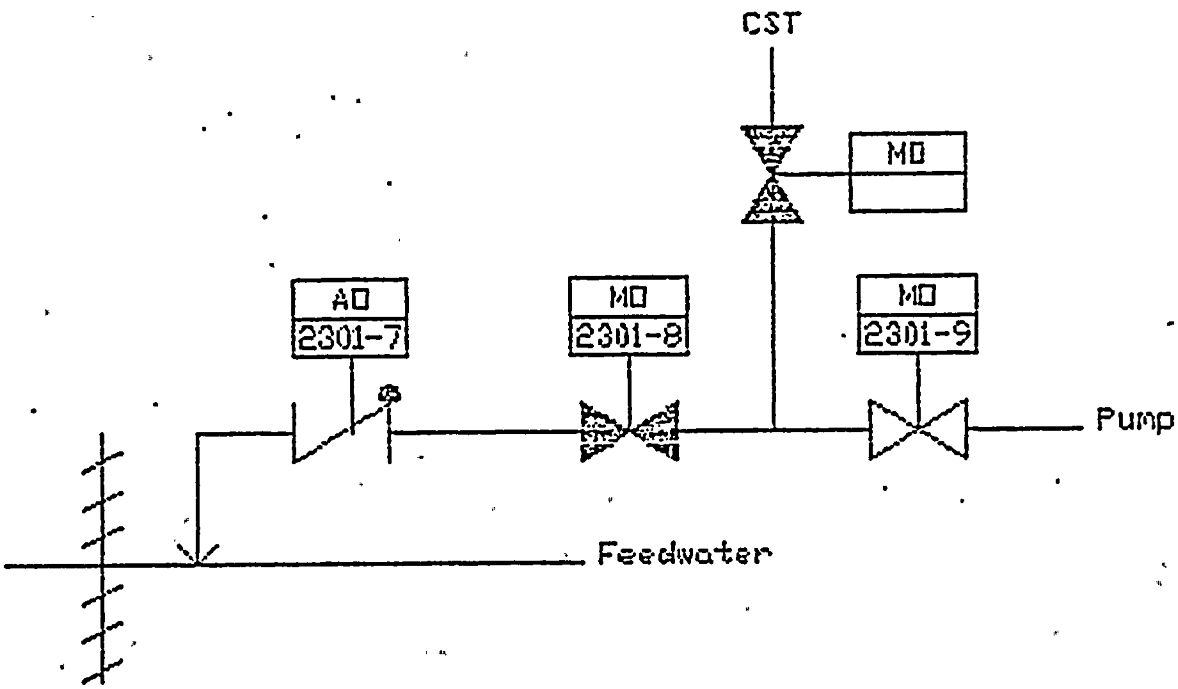


Figure B.6 Valve arrangement for HPCI injection line at Pilgrim on September 29, 1983.

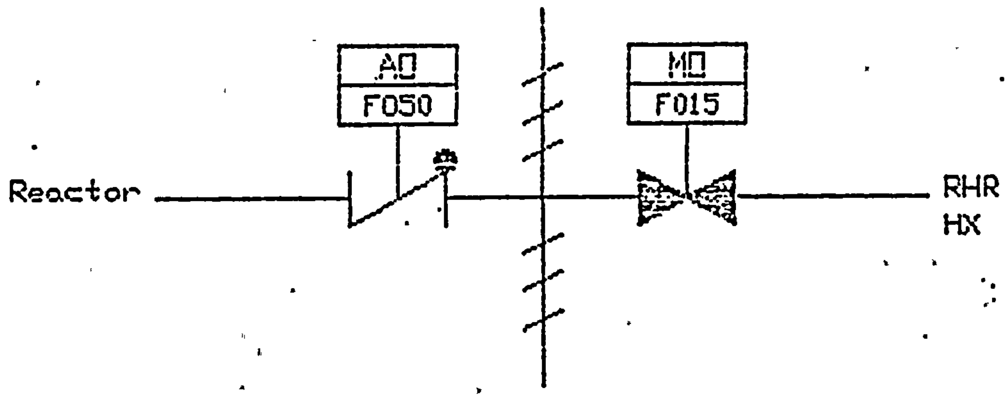


Figure B.7 Valve arrangement for LPCI injection line at Hatch-2 on October 28, 1983.

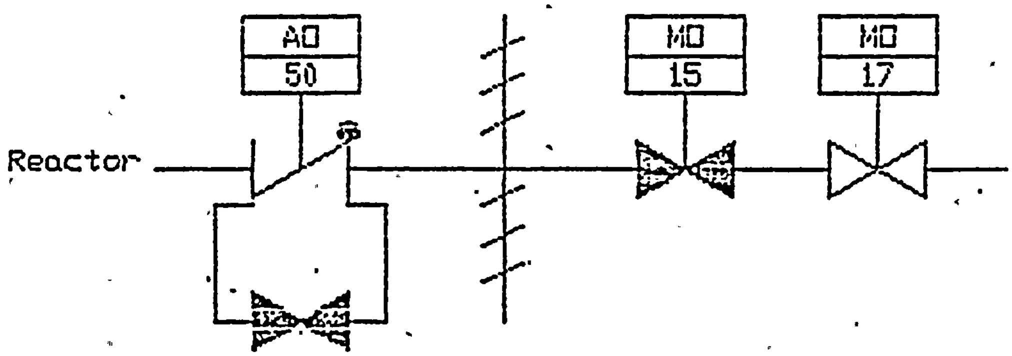


Figure B.8 Valve arrangement for LPCI injection line at Susquehanna on May 28, 1984.

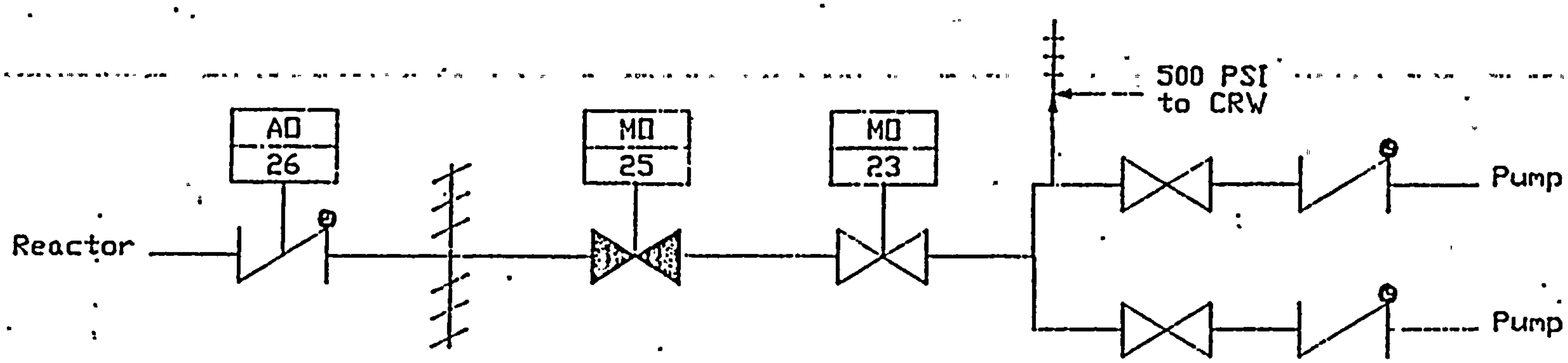


Figure B.9 Valve arrangement for core spray injection line at Browns Ferry-1 on August 14, 1984.

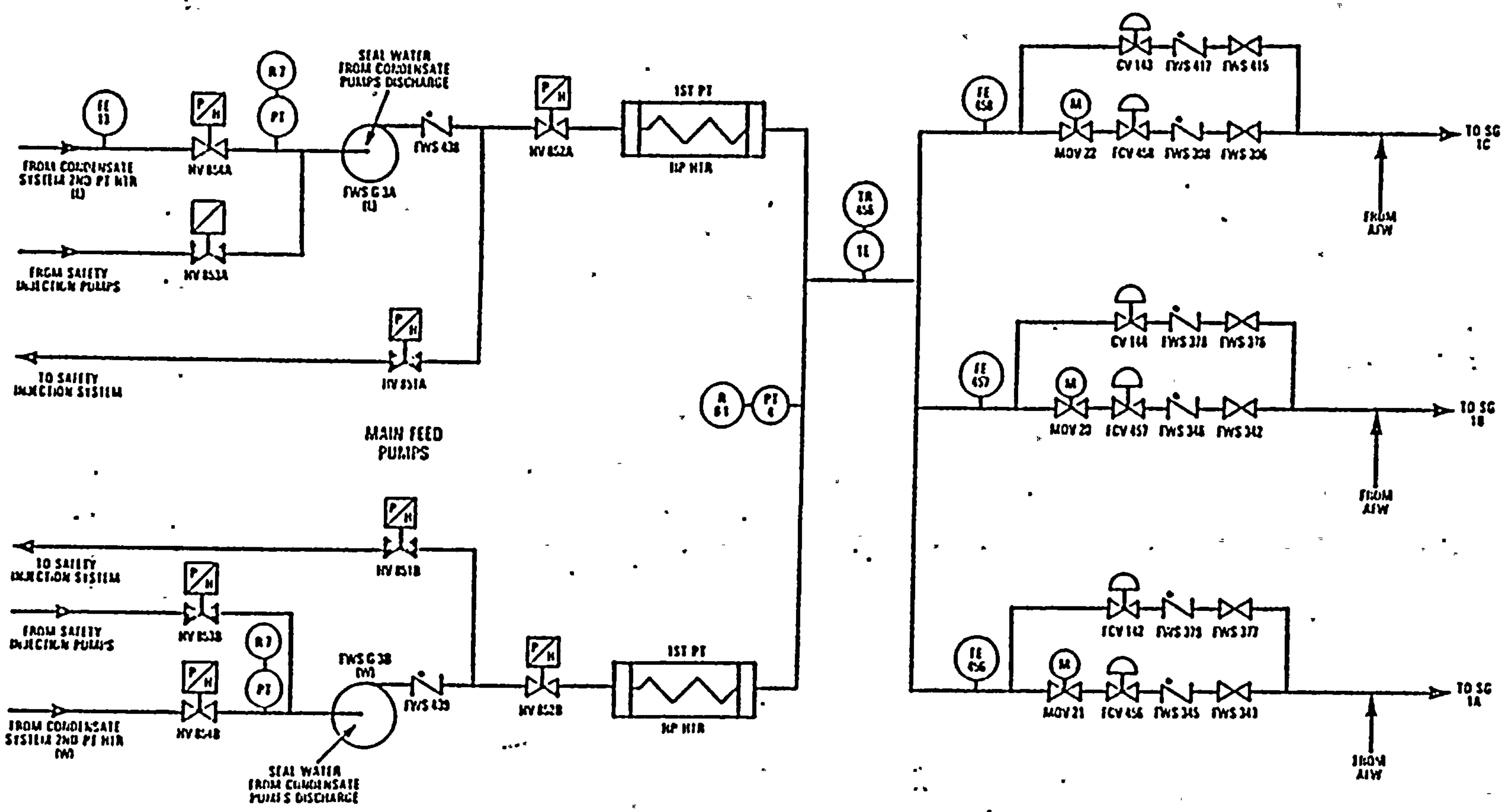


Figure B.10 Main feed system for San Onofre.

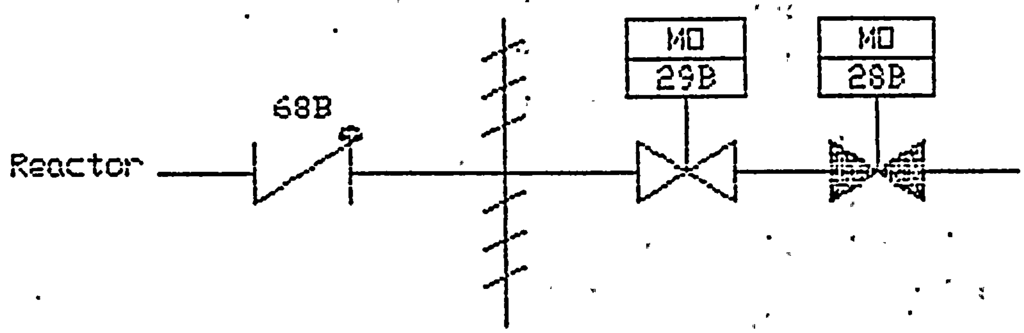


Figure B.11 Valve arrangement for LPCI injection line at Pilgrim on February 13, 1986.

Appendix D: Discussions on Data Used in Quantification of the Frequency of Interfacing LOCA

This appendix discusses the sources of some failure data listed in Table 4.1, and provides the derivation for the rest of the failure rate data listed in Table 4.1. Table 4.1 is reproduced in Table D.1. Each failure event in the table is discussed as follows.

1. MOV Rupture - This failure represents catastrophic failure of MOV such that the valve is widely open. A LER search was performed to identify failures of injection valves in LPCI, LPCS, HPCI/HPCS, and RCIC systems in BWRs. Five events were found, in which valve disc was separated from the stem. The number of injection valves for each plant was determined by the information provided in the event V inspection report for region I reactors[1] and the FSARs for other plants. The number of reactor years for each plant was obtained from the grey book dated February 1986. The total number of BWR injection valve years is the summation of the products of the number of injection valves and the number of reactor years. It is estimated to be 4173 valve years. Therefore, the failure rate is calculated as the number of failures divided by the number of valve years, i.e., 1.2×10^{-3} per year.

2. MOV Transfer Open - This failure mode represents failures in which a MOV is opened inadvertently due to human errors during test or maintenance, or due to failures of hardware such as valve control circuits and power supplies. The failure rate for this failure mode is taken from Seabrook PSA,[2] where generic data was used to estimate this failure rate.

3. MOV Failure to Close While Indicating Closed - This failure mode represents failures in which a MOV fails to close fully after being opened, such that the valve is leaking while the indication in the control room shows the valve is closed. The failure data for this failure mode is also taken from Seabrook PSA. This failure mode results in limited leakage through the valve. If an interfacing LOCA occurs with a MOV failed in this mode, the LOCA is limited to a small LOCA.

4. MOV Inadvertently Opened – This failure mode represents operator error during logic system functional test at Peach Bottom, such that the injection valve is opened inadvertently. While performing the test, the operator is supposed to energize a relay to inhibit the open signal to the injection valve. The procedure requires the operator to initial this step after performing it. If this step is skipped, the injection valve will open when the actuation signal is inserted. The human error probability for this event is taken from the handbook for human reliability analysis.[3] The probability of error of omission in use of written procedures, with clockoff provisions and long list of items, was used.

5-9. Air Operated Check Valve Failure Modes – The nine incidents of failures of air operated check valves identified in Section 3 are used to estimate the failure rates of five failure modes. Similar to the analysis done for MOV rupture, the number of air operated check valves at each BWR is estimated using the region I event "V" report and FSARs, and the number of reactor years is estimated based on the grey book. The number of valve years is estimated to be 1361. Therefore, the failure rate for each failure mode is equal to the number of events divided by 1361. For example, the frequency that the air operated check valve is held open due to reversed air supply is calculated based on two events, Browns Ferry-1 and Hatch, in 1361 years, i.e., 1.47×10^{-3} per year. Similarly, the frequency for the failure mode that the check valve is held open by foreign material is estimated using the Cooper incident. The frequency, that the check valve is opened due to rusted linkage between the valve stem and the air operator, is estimated using the Pilgrim incident. The frequency, that the valve is held open due to misalignment of gears between the check valve and its operator, is estimated based on the incident at LaSalle-1 on September 14, 1983. The four remaining failures identified in Section 3 represent leaks through the check valves. They are used to estimate the frequency of check valve leakage.

10. Check Valve Rupture – This represents catastrophic failure of the check valve. The failure rate is taken from the PSA procedures Guide,[4] where the failure rate was estimated using experts' opinion in a reliability data workshop.

11. Check Valve Leak - This failure mode applies to the pump discharge check valve in the high pressure core spray system of Nine Mile Point-2. The failure rate is assumed to be the same as that of the testable check valve.

12-15. Squares of Failure Rates - Some isolation valve arrangements involve two valves of the same type in series, e.g., RHR shutdown cooling suction and vessel head spray at Nine Mile Point-2. Therefore, two valves may fail due to the same failure mode, e.g., both RHR suction valves may fail due to rupture. The expression for the failure of both valves involves the square of the failure rate. Due to the uncertainties in the failure rates, the point values are considered the means of the probability distributions for them. The mean of the square of a random variable is related to the mean of the random variable by the following:

$$E(X^2) = (EX)^2 + \text{variance } (X)$$

where $E(X^2)$ is the mean of the square of X, EX is the mean of X, and variance (X) is the variance of X. In order to use this equation, the variance or the probability distribution of X is needed. How to calculate each of the squares of the failure rates is explained in the following:

MOV Rupture - The probability distribution for catastrophic failure of MOV, given in the PSA Procedure Guide,[4] is used as a prior distribution. A Bayes update using the evidence of five events in 4173 years is performed. The mean of the square is calculated using the discretized probability distribution for the posterior distribution.

MOV Leak - The probability distribution for this failure made is given in Seabrook PSA.[2] The parameters for the lognormal distribution are calculated to be

$$\mu = -9.429 \text{ and } \sigma = 0.808$$

The corresponding variance is $1.05\text{x}10^{-8}$.

AOV Leak - The probability distribution for minor internal leakage of check valves, given in PSA Procedures Guide,[4] was used as the prior distribution. A Bayes updating was performed using the evidence of four events in 1361 years to obtain a posterior distribution. The mean of the square was

calculated using the discretized probability distribution for the posterior distribution.

AOV Rusted Linkage – The same procedure as that for AOV leak was used except that the evidence was one event in 1361 years.

References

1. "Special Inspections Regarding Potential Intersystem Overpressurization of Emergency Core Cooling Systems (Event V Inspections)," Memo from Thomas E. Murley, Regional Administrator, Region I, to James M. Taylor, Director, Office of Inspection and Enforcement, USNRC, September 1985.

2. Pickard, Lowe and Garrick, Inc., "Seabrook Station Probabilistic Safety Assessment," Prepared for Public Service Company of New Hampshire and Yankee Atomic Electric Company, PLG-0300, December 1983.

3. A. D. Swain and H. E. Güttman, "Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications," NUREG/CR-1278, August 1983.

4. R. A. Bari et al., "Probabilistic Safety Analysis Procedures Guide," NUREG/CR-2815, July 1985.

Table D.1
Some Data Used in the Quantification of the
Frequency of Intersystem LOCAs

Failure Event	Failure Data	Sources
1. MOV Rupture	1.20×10^{-3}(/ry)	See Appendix D
2. MOV Transfer Open	8.10×10^{-4}(/ry)	Seabrook PRA
3. MOV Failure to Close While Indicating Closed	1.07×10^{-4}(/demand)	Seabrook PRA
4. MOV Inadvertently Opened	3×10^{-3}(/demand)	Handbook of Human Reliability Analysis
5. AOV Opened Due to Reversed Air Supply	1.47×10^{-3}(/ry)	See Appendix D
6. AOV Opened Due to Foreign Material	7.35×10^{-4}(/ry)	See Appendix D
7. AOV Opened Due to Rusted Linkage	7.35×10^{-4}(/ry)	See Appendix D
8. AOV Opened Due to Misalignment of Gears	7.35×10^{-4}(/ry)	See Appendix D
9. AOV Leak	2.94×10^{-3}(/ry)	See Appendix D
10.Check Valve Rupture	8.80×10^{-4}(/ry)	PSA Procedures Guide
11.Check Valve Leak	2.94×10^{-3}(/ry)	Same as AOV Leak
12.Lamda Rupture Square (MOV)	2.06×10^{-6}(/ry^2)	$EX^2=(EX)^2$+var.
13.Lamda Leak Square	2.20×10^{-8}(/ry^2)	$EX^2=(EX)^2$+var.
14.Lamda Leak Square (AOV)	1.09×10^{-5}(/ry^2)	$EX^2=(EX)^2$+var.
15.Lamda Rust Square	2.13×10^{-6}(/ry^2)	$EX^2=(EX)^2$+var.