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Interfacing Systems LOCA: Boiling Water Reactors

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EXECUTIVE SUMMARY

This study was performed by the Risk Evaluation Group, Department of Nuclear Energy, Brookhaven National Laboratory for the Office of Nuclear Regulatory Research, Reactor and Plant Safety Issues Branch, Division of Reactor and Plant Systems, U.S. Nuclear Regulatory Commission. The objectives of this study are to investigate the vulnerability of current boiling water reactor (BWR) designs to an interfacing systems LOCA (ISL), identify any improvements that would significantly reduce the frequency of ISLs, determine the cost-benefit considerations thereof, and determine the effects and the cost benefit relationship of instituting leak testing programs of the pressure isolation valves for those plants that do not currently have such a requirement.

This study is based upon the detailed examination of three plants (Peach Bottom, Nine Mile Point 2, and Quad Cities) with the goal of taking the plant-specific findings and extrapolating the results to aid in the resolution of NRC Generic Issue 105.

Recent BWR operating experience indicates that the pressure isolation valves may not adequately protect against overpressurization of low pressure systems. This overpressurization may result in the rupture of low pressure piping. This event, if combined with failures in the emergency core cooling systems (ECCS) and other systems (e.g. feedwater) that may be used to provide makeup to the reactor coolant system, could result in a core melt accident with the possible release of fission products outside the primary containment. Some ECCS failures may be a direct result of the initial rupture and/or its environmental effects.

One of the primary goals of this study was to determine the cost-benefit relationship associated with requiring plants that do not currently have leak testing requirements on their pressure isolation valves (PIVs) to institute such a program. However, all of the reference plants already have various requirements related to leak testing. Therefore it was decided that since none of the reference plants represented a true "base case" model in this area an additional base case model would have to be created. The base case model was taken to be the Peach Bottom model with the PIV leak testing aspects removed. Removing the leak testing benefits from the Peach Bottom model resulted in a large increase in predicted core damage frequency due to ISL. Based upon the results of a separate sensitivity study, it appears sufficient for the leak testing program to include provisions such that leak testing be performed at each refueling as well as after individual valve maintenance. The risk-based benefits calculated for this leak testing program show that such testing schemes are cost effective.

In addition, the offsite risk-based cost-benefit considerations for the suggested testing program were calculated to be fully cost effective whether or not the break in the low pressure system was assumed to be submerged under water. A submerged break would result in trapping of some of the aerosol fission products in the water and thus lower the predicted offsite consequences. The results indicate that in spite of uncertainty in predicting fission product release the benefits in risk reduction outweigh the cost of implementing such a leak testing program.

The insights from this study fall into two basic categories. The first category deals with assuring that the pressure boundaries are intact prior to increasing reactor pressure and the second category deals with how to avoid placing the plant unnecessarily into a more vulnerable mode of plant operation. Table 1 provides a convenient collection of the pertinent core damage frequencies (CDFs) presented throughout this report. The table will be used to facilitate comparisons and derive insights.

The first category above is addressed by PIV leak testing provisions. From Table 1, "Peach Bottom (no leak testing)" represents an analysis wherein the Peach Bottom model was stripped of all credit for its current leak testing practices. "Peach Bottom (current)" refers to the Peach Bottom plant as found and modelled. "Peach Bottom (with leak testing)" reflects the minimum leak testing provisions derived from this study (i.e. leak testing all air-operated check valves at each refueling and individually after maintenance). Comparing the "no-testing case" to "Peach Bottom (current)" shows that the existing level of leak testing has already reduced the Peach Bottom CDF due to ISLs by an order of magnitude. Comparing "Peach Bottom (current)" to "Peach Bottom (with leak testing)" shows another order of magnitude reduction is still available. A significant benefit (similar to that derived for Peach Bottom) for such a leak testing program is expected to hold across the BWR population.

The second category of insights is addressed by changing current testing practices. These testing practices can be almost as significant as implementation of a leak testing program, however, they are quite plant-specific. The dominant example from this study is found at Nine Mile Point 2 (NMP). By comparing the two NMP-2 entries in Table 1, there is apparently more than a two order of magnitude decrease in the CDF for ISL available by prohibiting the currently allowed practice of stroke testing the valves in the steam condensing lines to the RHR heat exchangers (with the reactor pressurized) and allowing the stroke testing to await a convenient shutdown (with the reactor depressurized).

A second example of significant testing-induced risk can be seen by comparing "Peach Bottom (current)" with "Peach Bottom (logic test at shutdown)" from Table 1. This is the single most effective corrective action identified for the Peach Bottom plant in reducing core damage frequency. Current Peach Bottom testing requirements include the provision to test the ECCS logic every six months independent of whether or not the reactor is pressurized. By holding off on the ECCS logic system functional test until a reactor shutdown comes along, (i.e., the reactor is depressurized), the ISL CDF can be reduced by almost an order of magnitude.

In summary, the results of this study show that institution of a minimum leak testing program for the air-operated pressure isolation check valves represents a significant reduction in the estimated ISL CDF for the three plants studied, which should apply across the entire BWR population. In addition, it has been shown that some of the current BWR testing practices can also represent a large contribution to ISL CDF and that this testing-induced risk is easily removed by rather simple and cost-effective changes to existing testing procedures (as discussed directly above).

Table 1
Summary of Estimated ISL CDF vs. Plant States

Plant State	CDF/Year
Peach Bottom (No leak testing)	1.86E-5
Peach Bottom (Current)	1.02E-6
Peach Bottom (With leak testing)	1.97E-7
Nine Mile Point 2 (Current)	8.81E-6
Nine Mile Point 2 (With all fixes)	3.22E-8
Peach Bottom (Logic test at shutdown)	1.21E-7

1. INTRODUCTION

1.1 Background

The term "interfacing system LOCA" (ISL) refers to a class of nuclear plant loss-of-coolant accidents in which the Reactor Coolant System (RCS) pressure boundary (isolation valve, piping wall, etc.) interfacing with a supporting system of lower design pressure is breached. A subclass of these accidents takes on special concern when the postulated flow path affects the availability of a safety system needed to mitigate the accident. This can occur by overpressurizing the system of lower design pressure and may further induce ruptures outside the primary containment, thus establishing discharge of coolant to the environment. Depending on the configuration and accident sequence, the Emergency Core Cooling Systems (ECCS) as well as other injection paths may fail, resulting in a core melt with primary containment bypass.

In spite of numerous analyses conducted in various probabilistic risk assessments (PRAs), both the probability and the consequence estimates for interfacing system LOCA (ISL) sequences are subject to substantial uncertainties. Depending on assumed valve failure modes, common cause contribution, valve monitoring, test and maintenance strategies, and statistical data handling methods, the total core damage frequency due to ISL accidents may vary from 10^{-4} to 10^{-8}/reactor year. The radiological consequences are also subject to large variations due to plant-specific features, the location of the break, and the radionuclide behaviour under the particular ISL sequence (e.g., break is below or above water level).

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 (V-events). The V-event arrangements were 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 boiling water reactors (BWRs).

As a result of that study and the TMI-2 accident, all light water reactors with an operating license granted on or before February 23, 1980 were required[2-3] to periodically test or continuously monitor the Event-V valves. Acceptable methods to assure component integrity include:

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

(2) periodic in-service testing (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.

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

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 their pumps but have pump suction piping rated below reactor coolant system pressure are not normally considered to be protected unless the pumps are of the positive displacement type. Pressure 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 the Technical Specifications.

Since early 1981, the Office of Nuclear Reactor Regulation (NRR) staff commenced backfitting operating reactors by requiring (via in-service inspection programs) leak testing of all pressure isolation valves (PIVs) that connect the high pressure RCS to lower pressure systems.[5] On April 20, 1981, orders were sent to 32 PWRs and 2 BWRs which required leak rate testing of Event-V PIVs.

In February 1985, the NRR staff established new acceptance criteria[6] for leak rate testing. 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 Requirements (CRGR) responded favorably to this change,[7] but questioned the safety rationale that was used to justify the full extent of the PIV testing that was required of the Near Term Operating License (NTOL) applications, and the retroactive applications to the operating reactors. To address the concern of CRGR, NRR put a program in place as part of Generic Issue 105 to develop the necessary information and technical basis 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 nine 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.[8] 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 Objectives

Recent BWR operating experience[9] indicates that the pressure isolation valves may not adequately protect against overpressurization of low pressure systems. The overpressurization may result in the rupture of low pressure piping. This event, if combined with failures in the emergency core cooling systems and other systems (e.g. feedwater) that may be used to provide makeup to the reactor coolant system, 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 effects.

The objective of this work is to provide technical support to the NRC, Reactor and Plant Safety Issues Branch, ORES, for the meaningful resolution of the generic issue. This work includes, survey and analysis of representative plants to determine the risk due to failure of pressure isolation valves, and determination of corrective actions such as valve leakage testing and prohibiting valve stroke testing while pressurized. In addition, to address the concerns of the CRGR,[7] a detailed risk-benefit study was undertaken to determine the cost-effectiveness of requiring those plants currently not required to perform any PIV leak testing to perform this testing on some minimum frequency.

1.3 Organization of Report

Section 2 and Appendix A provide detailed information on the interfacing lines identified for the selected plants. Section 3 and Appendix B provide detailed information on the survey of operating experience, and the causes of PIV failures. Section 4 and Appendix C provide the detailed quantification for the interfacing lines identified in Section 2 using the failure experience and data found in Section 3 and Appendix D, respectively. Section 5 identifies and evaluates possible design/procedural changes that could be made to address the significant items identified from the Section 4 results in order to lower the core damage frequency from interfacing systems LOCA. Section 6 is the regulatory analysis in which risk-based cost and benefit estimates for the proposed corrective actions are analyzed. Section 7 summarizes the results obtained and the most important conclusions.

1.4 References

1. "Reactor Safety Study - An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," 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.

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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

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5. "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.

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7. "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.

8. "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.

9. 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 POTENTIAL ISL PATHWAYS AT 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]

Interfacing lines for the selected plants were identified from their Final Safety Analysis Reports (FSARs). Each FSAR has a table of containment isolation valves for all lines penetrating containment. These tables have been incorporated into Appendix A. Some of the lines penetrating containment are not connected to the reactor coolant system, e.g., the residual heat removal (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. High Energy Lines - Lines that are designed for high pressure were considered further. For example, main steam lines, steam supply lines for RCIC and HPCI turbines, and lines in the reactor water cleanup system.

B. Small Lines - Lines with diameters less than 1-1/2" were 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. Injection Line of Control Rod Drive Pumps - 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 rated for high pressure and the suction side of the pumps is rated for low pressure. One scenario of an interfacing LOCA is that the discharge valves of the standby pump fail open, backflow through the pump overpressurizes the pump suction piping and causes the pump 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 results through the standby pump train. The operator can also isolate this by closing the motor-operated valves (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 were not included in the succeeding phases of this study.

D. Lines that are Connected to the Primary Coolant Pressure Boundary Outside the Containment by Normally Closed Pressure Isolation Valves (PIVs) - If the failure of the PIVs in a given line does not itself result 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 PIVs. If the normally closed valves fail open and feedwater pressure causes the flush line to rupture, feedwater will be diverted through the break. A 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 via the MOV downstream of this check valve. Similarly, in the reactor water cleanup system, there are many low pressure lines used for backwash and precoat of the filter demineralizer. They are isolated from the high pressure piping by two normally closed valves. If the valves fail open and cause a rupture of the low pressure piping, the containment isolation valves should still be able to isolate the reactor water cleanup system from the primary coolant system. A LOCA in these lines then requires failure of two additional containment isolation valves as well as the two PIVs. Therefore, the frequency of a 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. Lines that are not Connected to the Reactor Coolant System Need not be Considered - 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 eliminated 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 this study. A letter means that the line was not considered further, 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 rated for high pressure on the discharge side of the pumps, but rated for 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 rated for high pressure but the pump suction side is not. 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 details of this 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. This line 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 were to become closed. However, an isolation valve in the high pressure portion of the line itself would be expected to close and isolate the break. Given failure of this valve, the containment isolation valves would then act to isolate the system. This line is not considered further, because the frequency of an unisolated interfacing LOCA in it is judged to be negligible. 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 was 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 testing (LLRT) for containment isolation valves, leak rate testing for PIVs, and valve operability testing for valves in the ECCS.

3. Automatic and Manual Control of PIVs - This was based on P&IDs and system descriptions in the FSARs.

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

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

In addition to the information in Appendix A, attempts were made to collect the 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, or 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. ECCS pump suction piping in the suppression pool is 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 pursued 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.

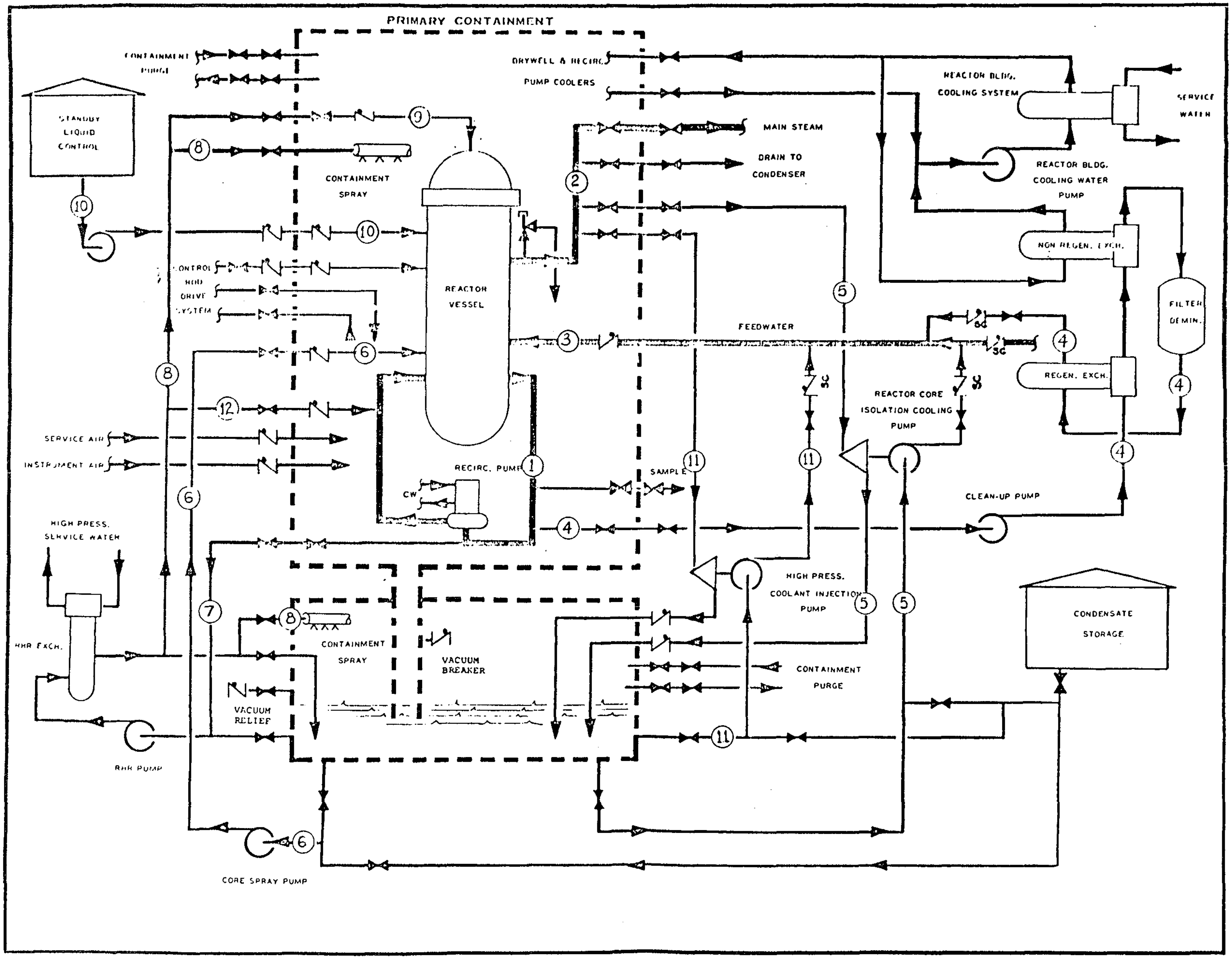

Figure 2.1 A simplified drawing for lines penetrating containment at Peach Bottom.

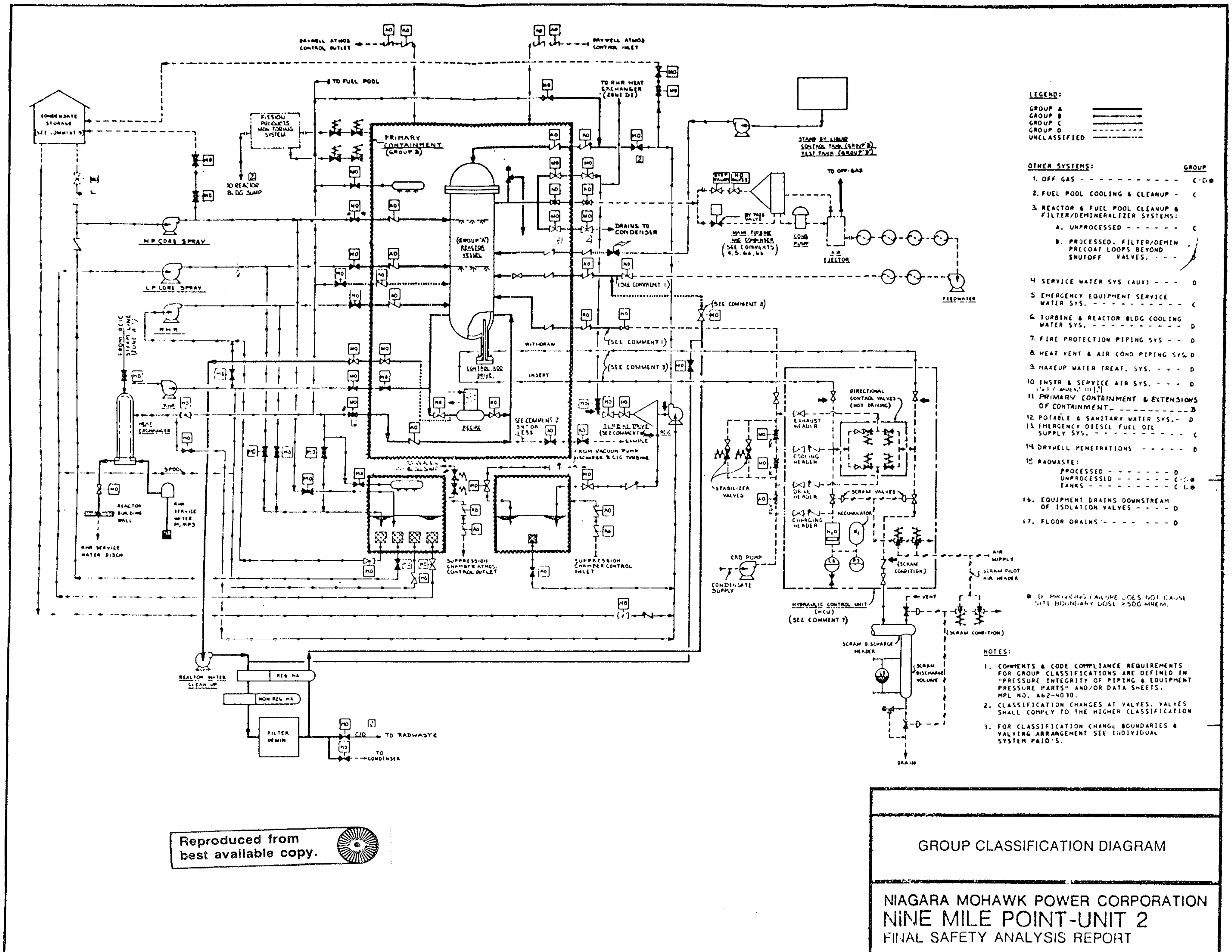

Figure 2.2 A simplified drawing for lines penetrating containment at Nine Mile Point-2.

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

Peach Bottom

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

Nine Mile Point 2

- 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

Quad Cities

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

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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] the NRC Office of Analysis and Evaluation of Operational Data (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 that 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 these 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 systems 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 systems 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 for 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 Licensing Event Report (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. Testable check valves are used inside the drywell in the injection lines of BWR ECCSs. 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 somewhat 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 hand-switch. This hand-switch 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 hand-switch 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, the HPCI 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 the low pressure piping took place.

If the low pressure piping had been overpressurized to the point that it ruptured, diversion of feedwater and unavailability of HPCI would have resulted. An interfacing LOCA would not have resulted unless the feedwater check valve inside the drywell also were to fail 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 an adjustment to the 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 only in cold shutdown.

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 an RHR System Relay Logic Test during 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 testing 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 dual 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 seat 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, a 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. These 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.

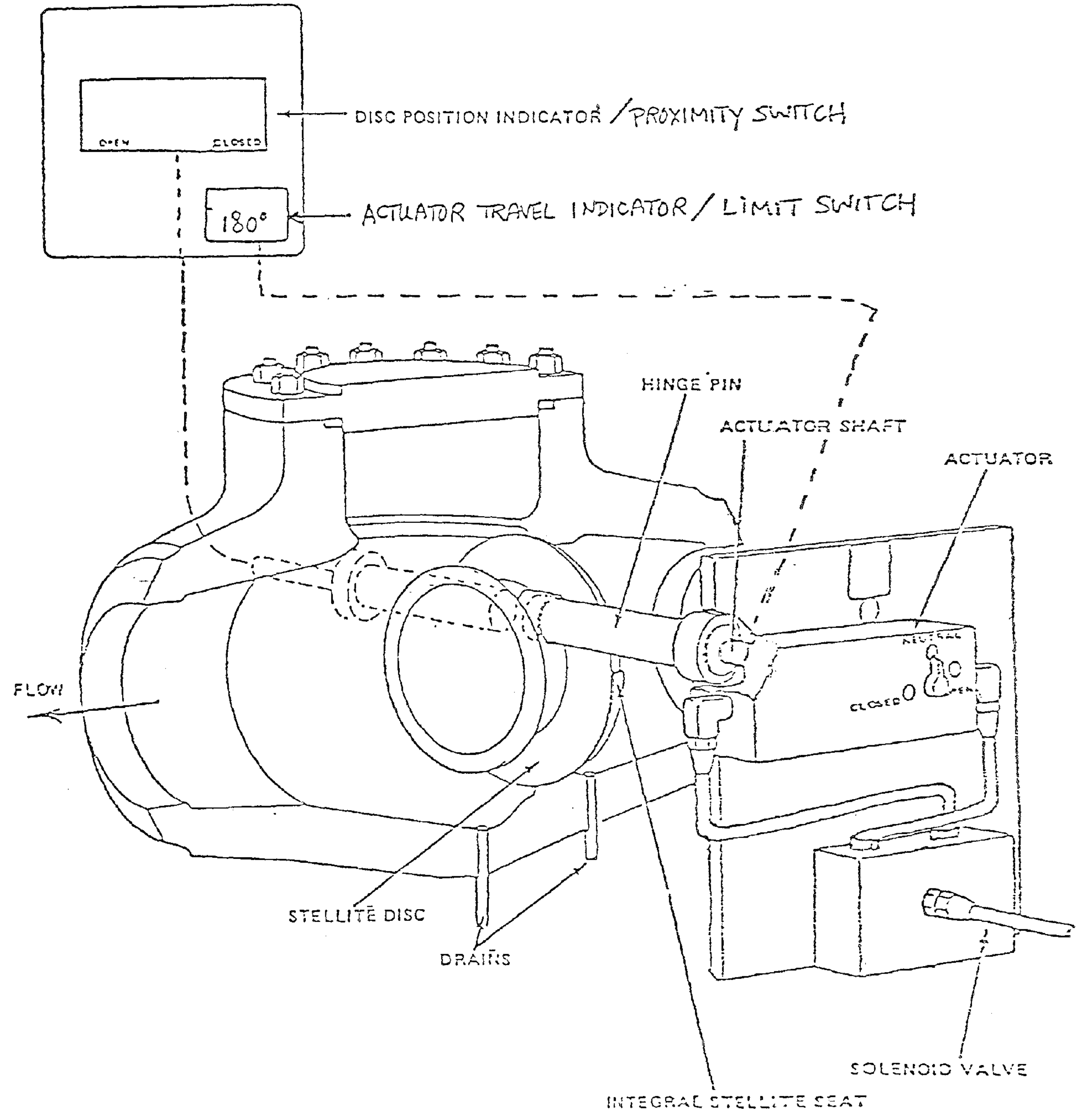
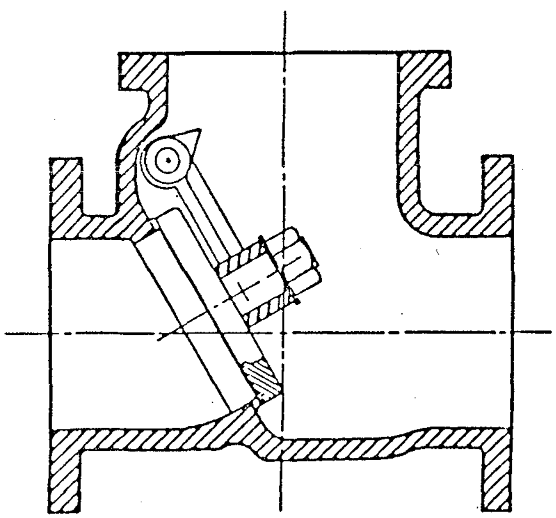
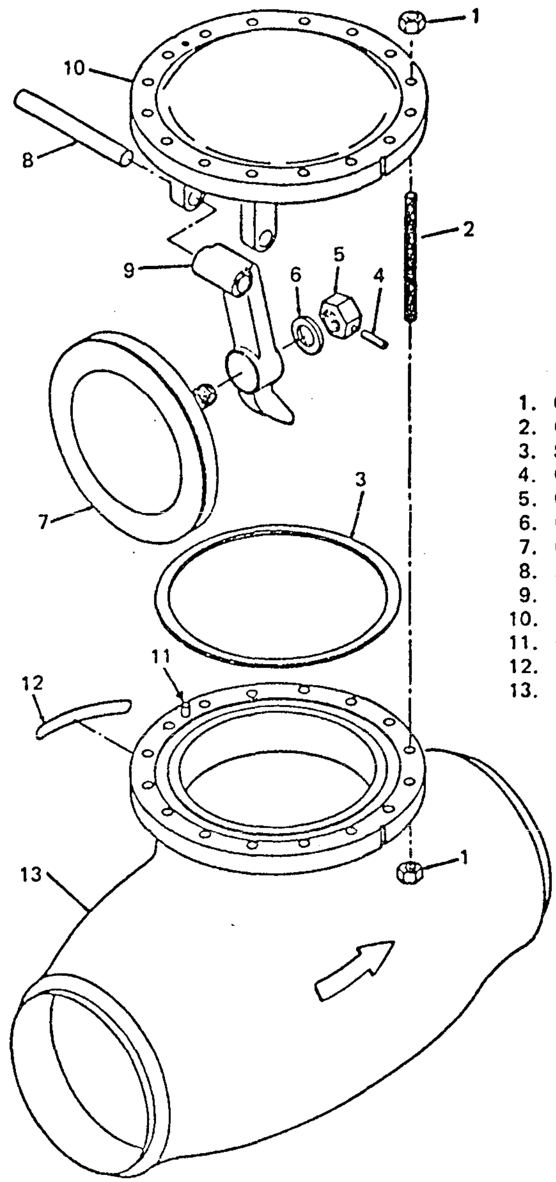


Figure 3.1 Testable check valve.





1. CAP STUD FASTENER NUT
2. CAP STUD FASTENER BOLT
3. SPIRAL WOUND GASKET
4. OBTURATOR FASTENER NUT PIN
5. OBTURATOR FASTENER NUT
6. OBTURATOR FASTENER NUT WASHER
7. OBTURATOR
8. HANGER PIN
9. HANGER
10. CAP
11. CAP PIN
12. IDENTIFICATION PLATE
13. BODY

Figure 3.2 Swing check valve.

Table 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 inappropriate 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 Functional 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 inappropriate 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 Increasing
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	Reactor Type	Date	Failure Mode	Source
Crystal River 3	PWR	April 5, 1980	Missing Disc Retainer Pin	LER 80-017
Surry 1	PWR	April 17, 1980	Disc Detached	LER 80-023
Crystal River 3	PWR	May 6, 1980	Missing Hinge Pin	LER 80-021
Turkey Point 3	PWR	April 1, 1981	Missing Disc Stud Nut Missing Pivot Pins	LER 81-007
Turkey Point 4	PWR	June 8, 1982	Missing Disc Stud Nut	LER 81-008
LaSalle 1	BWR	October 4, 1984	Hinge Pin Busing Moved Moved Out of Disc	LER 84-064
Quad Cities 2	BWR	March 18, 1985	Missing Hinge Pin	NPE B.14.A.161
Brunswick 2	BWR	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 approach used in the quantification of the frequency of overpressurization in the interfacing lines identified in the analysis documented in Section 2, and the frequency of core damage as a result of the overpressurization. A detailed description of the analysis for the LPCI lines of Peach Bottom is provided here for illustration. Appendix C includes the line by line analysis for the three selected plants.

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 of those identified failures 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 assess the frequencies of different combinations of PIV failure modes that will lead to overpressurization.

Given that a segment of low pressure piping could be overpressurized, 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. Given that the low pressure piping is overpressurized, the probability that a rupture occurs is assessed in Appendix E. Basically, a probability distribution representing the strength of the ASTM A106 Grade B carbon Steel was assessed. The hoop stress at 1050 psi in a pipe section of a given diameter and thickness is then used to determine the rupture probability. Tables 4.2 to 4.4 list, for all interfacing lines of the three reference plants, the diameter and thickness of the pipe sections that will be overpressurized if the PIVs in the interfacing line fail open. Also listed in the tables are the probabilities of pipe rupture assessed in Appendix E. 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. Given that the BWR Owners' Group work was focused on pipe welds, it is believed to provide a lower bound for the rupture probability, i.e., if the rupture probability assessed in Appendix E is lower than 3×10^{-5}, then 3×10^{-5} is used in the quantification of core damage frequencies. Appendix F provides the core damage frequency results of sensitivity calculations using three values for the probability of rupture; 10^{-1}, 10^{-3}, and 3.0×10^{-5}.

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 or to keep the valve open in the presence of blowdown flow. 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 conservatively assumed that core damage will result due to either structural failure, flooding of ECCS equipment, or draining of the suppression pool. This results in sequence 5 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 the ECCS is made inoperable by the blowdown, the condensate pumps may be available to provide makeup to the reactor coolant system. In this study, no credit is given to the condensate pumps, because the operability of the condensate pumps may be affected by the blowdown, and timely operator response would be required.

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 was used to assess the probability that the operators fail to isolate the small LOCA. This probability 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 actual probabilities used in the figure apply to a small LOCA in the RHR room of Peach Bottom. Sequence 4 in Figure 4.1 represents the case that a pipe rupture occurs as a result of the overpressurization, the check valve partially closes on reverse flow and the operator fails to isolate the small LOCA that is assumed to have occurred through the check valve.

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 perform a controlled depressurization 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 the operators 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. This probability is approximately $5x10^{-4}$ at two hours. It is conservatively assumed that if the operators fail to depressurize in two hours, all ECCS would become disabled due to flooding. This results in sequence 4 or 5 and sequence 9 or 10 in Figure 4.3. A probability of $5x10^{-2}$ was 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,

$$
\begin{aligned}
& P(\text{failure to depressurize} \mid \text{failure to isolate}) \\
&= P(\text{failure to depressurize and failure to isolate}) \\
&\quad /P(\text{failure to isolate}) \\
&= 5x10^{-4}/10^{-2} \\
&= 5x10^{-2}
\end{aligned}
$$

It was 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 was 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 the ECCS is disabled due to flooding. The assessment of the unavailabilities of the systems in Figure 4.3 is described as follows.

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

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

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

- LPCI & LPCS - Based on the results of the BNL review[5] of the Shoreham PRA, the unavailabilities of LPCI and LPCS were taken to be $2.7x10^{-3}$ and $3.6x10^{-3}$, respectively. The unavailability of both systems is $6.2x10^{-4}$. Since one loop of LPCI is assumed unavailable, the unavailability of both systems should be between $3.6x10^{-3}$ and $6.2x10^{-4}$. $1.0x10^{-3}$ is used in the analysis.

- Condensate Pump - The unavailability is based on Ref. 5 and is dominated by 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 4.5. The following is an analysis of the LPCI lines of Peach Bottom using the above approach. Appendix C provides detailed line by line analyses for the three reference plants. The overall results for the three reference plants are summarized in Table 4.6. Tables 4.7 to 4.9 summarize the line by line results for the three selected plants.

An Analysis of the LPCI Lines of Peach Bottom

The analysis of the LPCI lines of Peach Bottom is discussed here as an example. First, the test requirements for the PIVs are discussed and their effect on valve operability is considered. Then, frequency estimates are made based on operating event experience, current data searches, and where necessary, already published generic data.

Test Requirements for Pressure Isolation Valves

A. Operational Hydrostatic Test

This test is done before startup after each 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. The testable check valves and the inboard injection valves of the LPCI lines of Peach Bottom are required to be tested and the success criterion is 720 cc per hour.

B. 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 procedure for the RHR system requires 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.

C. Local Leak Rate Test (LLRT)

This is the type "C" test for containment isolation valves defined and discussed in Appendix J to 10CFR50. The injection valves in the RHR system are required to be tested. 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 are specified in terms of aggregate leakage through all containment isolation valves and all containment

penetrations. The total leakage rate must 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 are specified for individual valves, excessive leakage is expected to be detected during LLRT, because each individual leakage rate is recorded.

D. 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 with the reactor pressure 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 recorded. The testable check valves are cycled only during a shutdown greater than 48 hours or after valve maintenance.

Assessment of Frequency of Overpressurization and Frequency of Core Damage

The quantitative analysis for the LPCI injection lines is described in detail here and summarized in Table 4.10. 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., $2/1361 = 1.47 \times 10^{-3}$/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 differential pressure across the inboard MOV is less than 100 psi. If the outboard MOV fails to fully close, the operators will have a problem pressurizing the pipe section. Therefore, this 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, this 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} was used for this operator error. Therefore, the probability that the MOV fails to fully reclose and the failure goes undetected is

$$1.07x10^{-4}/\text{demand} * 6 \text{ demand} * 3x10^{-3} = 1.93x10^{-6},$$

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

$$1.2x10^{-3}/\text{ry} * 0.5 \text{ ry} = 6.0x10^{-4},$$

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 $3x10^{-3}$ was used for such failure and was taken from Table 20.7 of the Human Reliability Handbook.[6]

Another failure mode of the MOV is that the MOV could be 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 4.10. The failure rate, $8.1x10^{-4}$, 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., $7.35x10^{-4}$ per reactor year.

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

$$1.47x10^{-3} \text{ x } (1.93x10^{-6} + 6.0x10^{-4} + 3.00x10^{-3} + 4.05x10^{-4}) + 7.35x10^{-4}$$
$$= 7.41x10^{-4}/\text{ry}.$$

To determine the frequency of LOCA in such a 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. This would lift the relief valves, but would 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} was 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

$$1.47x10^{-3} \text{ x } 1.93x10^{-6} \text{ x } 0.01 = 2.83x10^{-11}/\text{yr}.$$

In the case of MOV rupture or inadvertent opening, the MOV would be 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 was 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 was 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 the MOV is

$$1.47x10^{-3} \text{ x } 6.0x10^{-4} \text{ x } 2.65x10^{-2} \text{ x } 0.01 = 2.34x10^{-10}/\text{ry},$$

where 2.65×10^{-2} is the probability that a pipe rupture occurs due to the overpressurization. Similarly, the contribution due to inadvertent opening of the MOV is

$$1.47\times10^{-3} \times 3\times10^{-3} \times 2.65\times10^{-2} \times 0.01 = 1.17\times10^{-9}/\text{ry},$$

the contribution due to transfer opening of the MOV is

$$1.47\times10^{-3} \times 4.05\times10^{-4} \times 2.65\times10^{-2} \times 0.01 = 1.58\times10^{-10}/\text{ry},$$

and the contribution due to the Browns Ferry scenario is

$$7.35\times10^{-4} * 2.65\times10^{-2} * 0.01 = 1.95\times10^{-7}/\text{ry}.$$

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

$$1.47\times10^{-3} \times 6.0\times10^{-4} \times [(1-2.65\times10^{-2})\times10^{-2}+2.65\times10^{-2}\times9.9\times10^{-3}] = 8.82\times10^{-9}/\text{ry}.$$

Similar contribution due to inadvertent opening is

$$1.47\times10^{-3} \times 3\times10^{-3} [(1-2.65\times10^{-2})\times10^{-2}+2.65\times10^{-2}\times9.9\times10^{-3}] = 4.41\times10^{-8}/\text{ry}.$$

The contribution due to transfer opening is

$$1.47\times10^{-3} \times 4.05\times10^{-4} [(1-2.65\times10^{-2}) \times 10^{-2} + 2.65\times10^{-2} \times 9.9\times10^{-3}] = 5.95\times10^{-9}/\text{ry}.$$

The contribution of the Browns Ferry scenario is

$$7.35\times10^{-4} * [(1-2.65\times10^{-2}) * 10^{-2}+2.65\times10^{-2} * 9.9\times10^{-3})] = 7.35\times10^{-6}/\text{ry}.$$

Table 4.10 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. It can be seen in Table 4.10 that the Browns Ferry scenario is the dominant contributor to the frequencies of overpressurization, small LOCA and large LOCA in the LPCI lines of Peach Bottom. This is because the scenario is judged to be an applicable scenario for Peach Bottom and the frequency of overpressurization is estimated using this experience. The fact that this scenario is already covered in the failure combination that the AOV fails due to reversed air supply and the MOV is opened inadvertently, is a double counting. However, the effect of this on the result is negligible, because the Browns Ferry scenario has a frequency that is more than two orders of magnitude higher than that of the failure combinations.

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 close 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 4.10 involve leakage through the testable check valve. They were 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.

4.1 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.

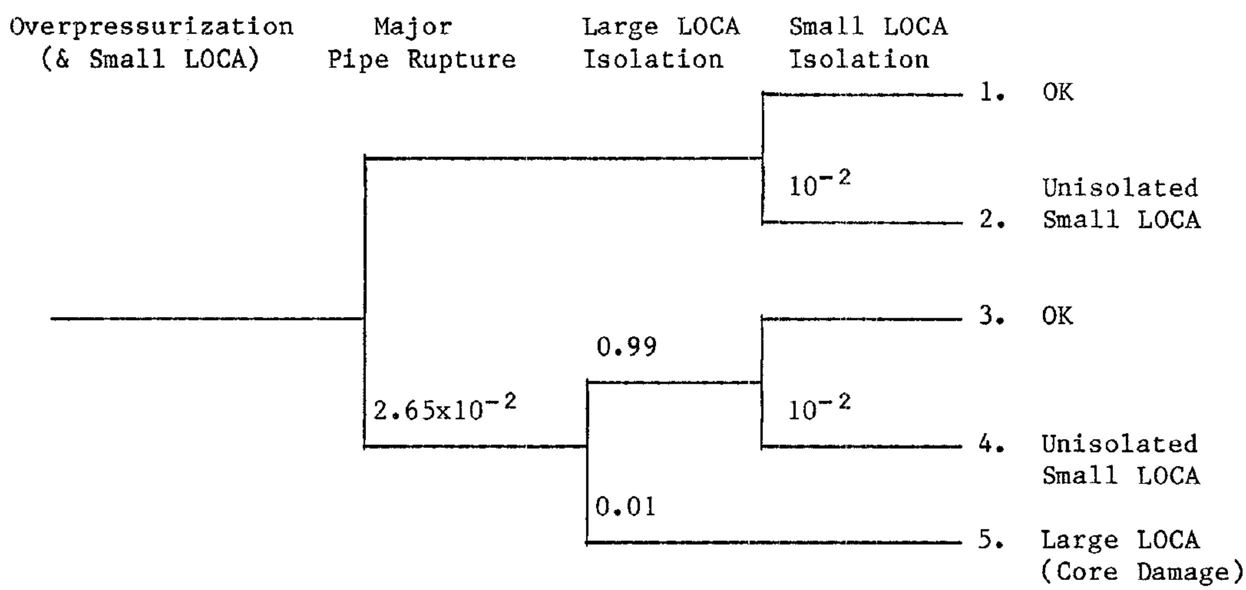


Figure 4.1. Event tree for conditional probability of LOCAs resulting from an overpressurization.

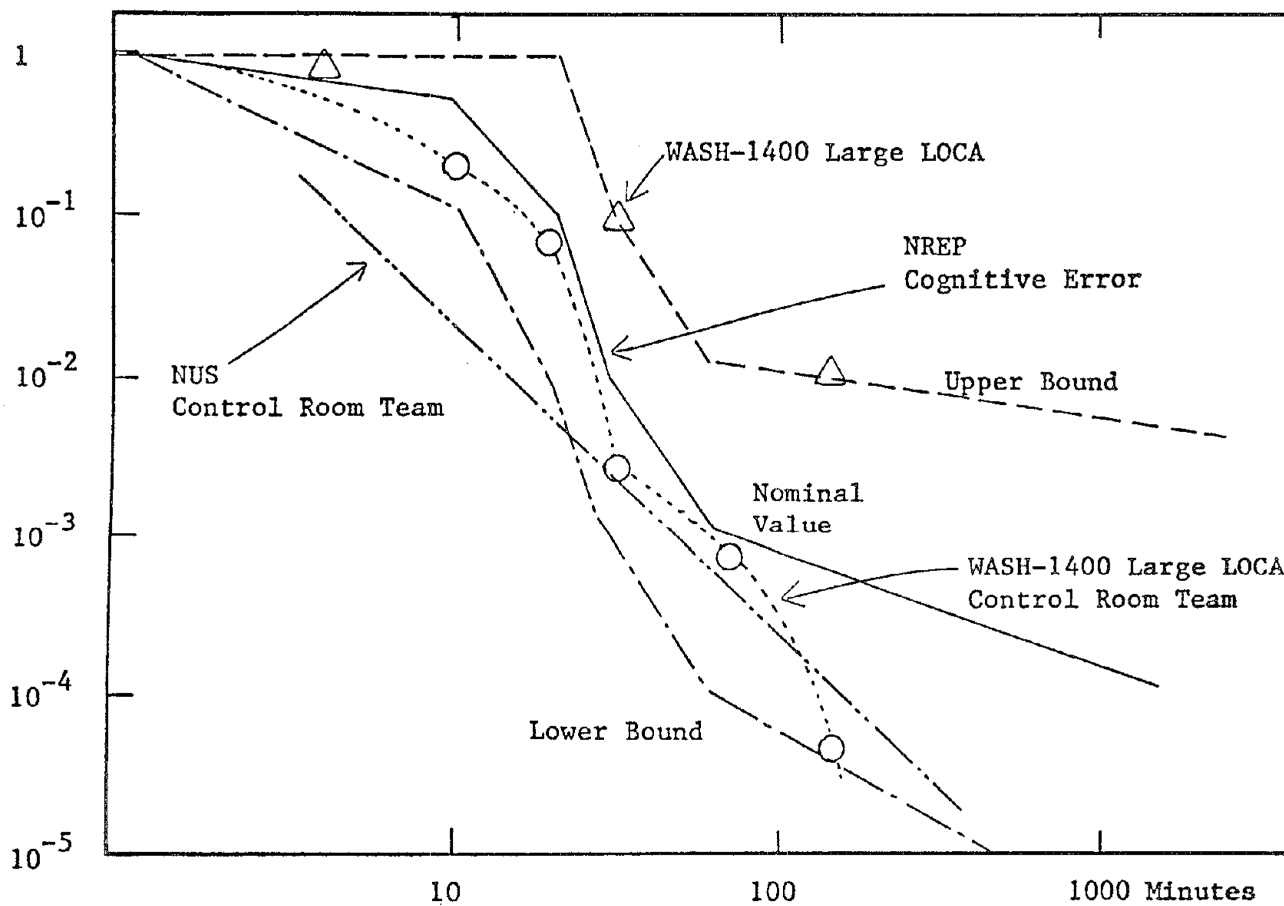


Figure 4.2. Time curves for operator actions.

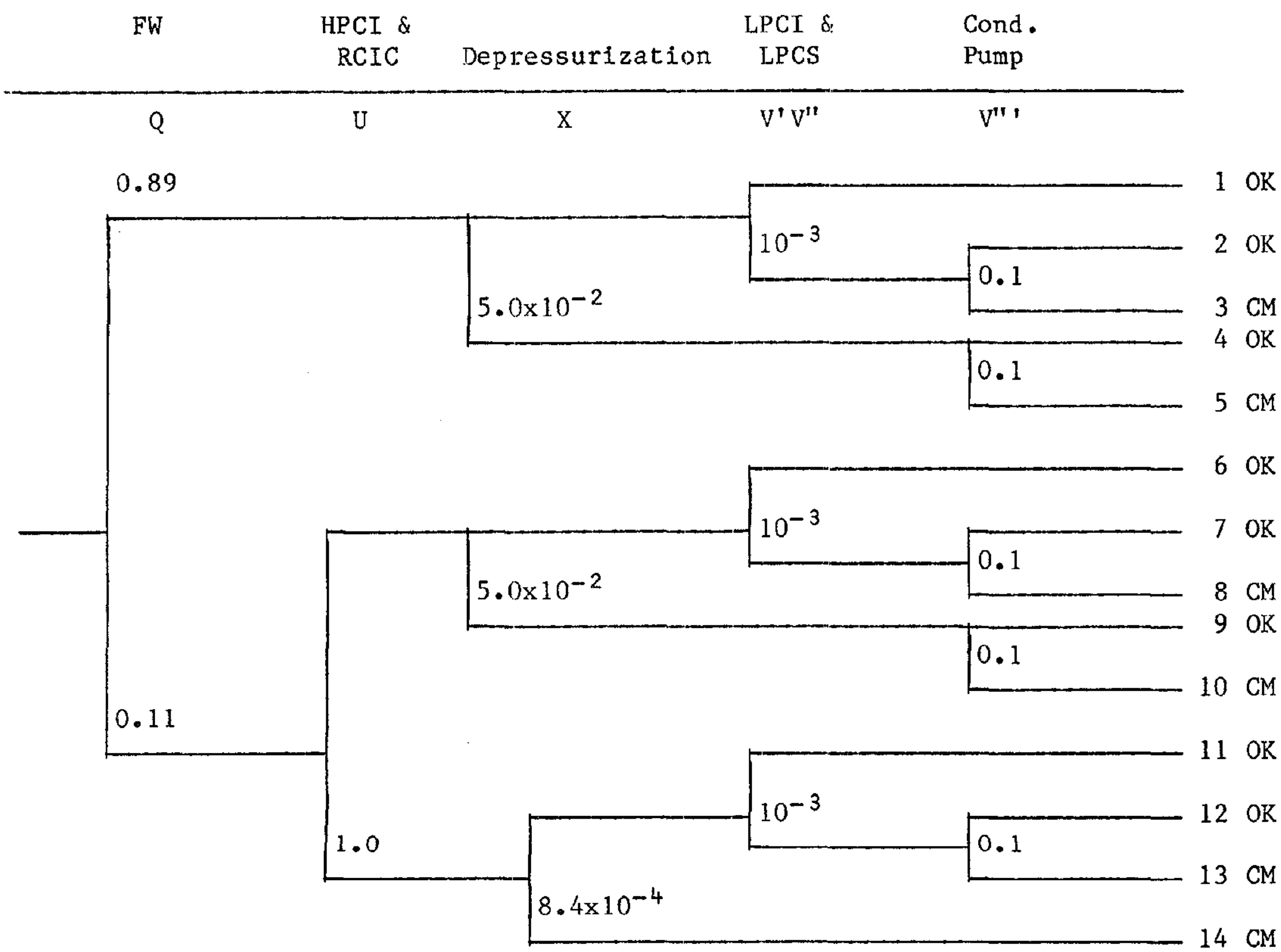


Figure 4.3. Event tree for a small LOCA outside the containment (LPCI line at Peach Bottom).

Table 4.1
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)	$EX^2=(EX)^2+var.$

Table 4.2
Pipe Rupture Probabilities for Peach Bottom

Interfacing Lines	Pipe Section	Nominal Pipe Size D (in.)	Pipe Thickness t (in.)	Failure Probability
LPCI and Vessel Head Spray	Injection Line	24	0.5	1.17×10^{-2}
	Vessel Head Spray	6	0.28	1.74×10^{-3}
	Containment Spray	12	0.375	3.95×10^{-3}
	Fuel Pool Cooling	16	0.375	9.34×10^{-3}
	Pump Discharge	20	0.375	2.65×10^{-2}
	Test Line to Suppression Pool	18	0.375	1.58×10^{-2}
RHR Suction	Suction Line	20	0.375	2.65×10^{-2}
	Suction Line	24	0.375	7.48×10^{-2}
	Fuel Pool Cooling	16	0.375	9.34×10^{-3}
Core Spray	Injection Line	12	0.375	3.95×10^{-3}
	Injection Line	14	0.375	5.52×10^{-3}
	Test to Suppression Pool	10	0.365	2.54×10^{-3}
HPCI	Pump Suction	14	0.375	5.52×10^{-3}
	Suction for CST	16	0.375	9.34×10^{-3}
RCIC	Pump Suction	6	0.28	1.74×10^{-3}
Feedwater	Suction Piping	20	0.593	2.81×10^{-3}
	Suction Piping	12	0.375	3.95×10^{-3}

Table 4.3
Pipe Rupture Probabilities for Nine Mile Point-2

Interfacing Lines	Pipe Section	Nominal Pipe Size D (in.)	Pipe Thickness t (in.)	Failure Probability
LPCI, Shutdown Cooling Return, and Steam Condensing	Injection	18	0.5	3.84×10^{-3}
	SDC Return	12	0.375	3.95×10^{-3}
	Drywell Spray	16	0.5	2.63×10^{-3}
	Vessel Head Spray	6	0.28	1.74×10^{-3}
	To S.P. Spray	4	0.237	1.19×10^{-3}
	Fuel Pool Cooling	8	0.322	2.14×10^{-3}
	RCIC Suction	4	0.237	1.19×10^{-3}
	Inlet to HX	20	0.812	1.06×10^{-3}
	Steam Condensing	8	0.5	6.07×10^{-4}
RHR Suction	Suction Line	20	0.5	5.60×10^{-3}
	Suction Line	18	0.375	1.58×10^{-2}
	Fuel Pool	10	0.365	2.54×10^{-3}
LPCS	Injection to S.P.	16	0.5	2.63×10^{-3}
		12	0.375	3.95×10^{-3}
HPCS	Suction from S.P.	14	0.375	5.52×10^{-3}
		3	0.216	9.23×10^{-4}
		20	0.375	2.65×10^{-2}
RCIC	Suction	6	0.28	1.74×10^{-3}
Feedwater	Suction	24	0.968	1.03×10^{-3}

Table 4.4
Pipe Rupture Probabilities for Quad Cities

Interfacing Lines	Pipe Section	Nominal Pipe Size D (in.)	Pipe Thickness t (in.)	Failure Probability
LPCI and Vessel Head Spray	Injection Line	16	0.375	9.34×10^{-3}
	Drywell Spray	10	0.365	2.54×10^{-3}
	Crosstie	18	0.437	6.94×10^{-3}
	Vessel Head Spray to S.P.	4	0.237	1.19×10^{-3}
		14	0.375	5.52×10^{-3}
		6	0.28	1.74×10^{-3}
	Pump Discharge	12	0.375	3.95×10^{-3}
RHR Suction	Suction Line	20	0.375	2.65×10^{-2}
	Fuel Pool Cooling	14	0.375	5.52×10^{-3}
		6	0.28	1.74×10^{-3}
Core Spray	Injection to S.P.	12	0.375	3.95×10^{-3}
		8	0.337	1.81×10^{-3}
HPCI	Suction	16	0.375	9.34×10^{-3}
		4	0.237	1.19×10^{-3}
RCIC	Suction	6	0.28	1.74×10^{-3}
Feedwater	Suction	30	0.625	9.96×10^{-3}
		20	0.5	5.60×10^{-3}
		16	0.375	9.34×10^{-3}
		12	0.375	3.95×10^{-3}

Table 4.5
Line Specific Failure Probabilities Used
in the Small LOCA Event Trees

	Q	U	X	V'V"	V"'	CDP
<u>Peach Bottom</u>						
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	$4.64x10^{-3}$
<u>Quad Cities</u>						
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
<u>Nine Mile Point-2</u>							
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 4.6
Summary of Results

Plant	f(OP)	S2	A	CDF
Peach Bottom	9.23E-03	3.12E-05	4.82E-06	1.02E-06
Nine Mile Point-2	9.92E-03	6.07E-05	9.83E-06	8.81E-06
Quad Cities	6.89E-03	4.16E-05	1.07E-05	9.32E-07

See Note 1.

Table 4.7
Summary of Results for Peach Bottom

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.52E-03	2.65E-02	1.52E-05	7.06E-07	7.77E-07
CS	1.52E-03	5.52E-03	1.52E-05	1.15E-07	1.85E-07
HPCI	2.59E-03	9.34E-03	0.00E+00	2.64E-08	2.64E-08
RCIC	2.59E-03	1.74E-03	0.00E+00	4.91E-09	4.91E-09
Feedwater	1.00E-03	3.95E-03	0.00E+00	3.95E-06	4.42E-09
RHR Suction	7.71E-07	7.48E-02	7.52E-07	1.93E-08	2.27E-08
Vessel Head Spray	4.53E-08	2.65E-02	4.49E-08	4.01E-10	6.10E-10

See Note 2.

Table 4.8
Summary of Results for Nine Mile Point-2

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.33E-05	3.95E-03	7.98E-06	8.84E-09	9.97E-09
LPCS	3.69E-06	3.95E-03	2.22E-06	2.92E-11	3.43E-10
SDC Return	8.86E-06	3.95E-03	5.32E-06	5.89E-09	6.64E-09
HPCS	2.65E-07	2.65E-02	2.65E-07	8.61E-14	5.29E-11
Vessel Head Spray	4.35E-06	1.74E-03	5.05E-08	9.28E-13	2.21E-10
Feedwater	1.00E-03	1.03E-03	0.00E+00	1.03E-06	1.15E-09
RHR Suction	7.71E-07	1.58E-02	7.67E-07	4.07E-09	4.15E-09
Steam Condensing	8.89E-03	3.95E-03	4.40E-05	8.78E-06	8.78E-06

See Note 2.

Table 4.9
Summary of Results for Quad Cities

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	2.07E-03	9.34E-03	2.07E-05	5.60E-07	6.71E-07
CS	2.01E-03	3.95E-03	2.01E-05	1.20E-07	2.28E-07
HPCI	9.03E-04	9.34E-03	0.00E+00	8.79E-09	8.79E-09
RCIC	9.03E-04	1.74E-03	0.00E+00	1.64E-09	1.64E-09
Feedwater	1.00E-03	9.96E-03	0.00E+00	9.96E-06	1.12E-08
RHR Suction	7.71E-07	2.65E-02	7.64E-07	6.82E-09	1.09E-08
Vessel Head Spray	4.53E-08	9.34E-03	4.52E-08	1.41E-10	3.84E-10

See Note 2.

Table 4.10
Summary Calculations for LPCI of Peach Bottom

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Browns Ferry-1 Hatch-2 (Reverse Air)	1.47E-03	1.93E-06 Failure to Reclose	2.83E-09	0.00E+00	2.83E-11	0.00E+00
		6.00E-04 Rupture	8.82E-07	2.65E-02	8.81E-09	2.34E-10
		3.00E-03 Inadvertent Opening	4.41E-06	2.65E-02	4.41E-08	1.17E-09
		4.05E-04 Transfer Open	5.95E-07	2.65E-02	5.95E-09	1.58E-10
Browns Ferry Scenario (Reverse Air,Inadvertent Opened)			7.35E-04	2.65E-02	7.35E-06	1.95E-07
Cooper (Foreign Material)	7.35E-04	1.93E-06 Failure to Reclose	1.42E-09	0.00E+00	1.42E-11	0.00E+00
		6.00E-04 Rupture	4.41E-07	2.65E-02	4.29E-09	1.17E-08
		3.00E-03 Inadvertent Opening	2.20E-06	2.65E-02	2.15E-08	5.84E-08
		4.05E-04 Transfer Open	2.98E-07	2.65E-02	2.90E-09	7.89E-09
Pilgrim-1 Sept. 29,1983 (Rusted Linkage)	7.35E-04	1.93E-06 Failure to Reclose	1.42E-09	0.00E+00	1.42E-11	0.00E+00
		6.00E-04 Rupture	4.41E-07	2.65E-02	4.41E-09	1.17E-10
		3.00E-03 Inadvertent Opening	2.20E-06	2.65E-02	2.20E-08	5.84E-10
		4.05E-04 Transfer Open	2.98E-07	2.65E-02	2.97E-09	7.89E-11
LaSalle-1 Sept. 14,1983 (Misalignment of Gears)	7.35E-04	1.93E-06 Failure to Reclose	1.42E-09	0.00E+00	1.42E-11	0.00E+00
		6.00E-04 Rupture	4.41E-07	2.65E-02	4.29E-09	1.17E-08
		3.00E-03 Inadvertent Opening	2.20E-06	2.65E-02	2.15E-08	5.84E-08
		4.05E-04 Transfer Open	2.98E-07	2.65E-02	2.90E-09	7.89E-09
Four Remaining Incidents (Leakage)	2.94E-03	1.93E-06 Failure to Reclose	5.66E-09	0.00E+00	5.66E-11	0.00E+00
		6.00E-04 Rupture	1.76E-06	0.00E+00	1.76E-08	0.00E+00
		3.00E-03 Inadvertent Opening	8.82E-06	0.00E+00	8.82E-08	0.00E+00
		4.05E-04 Transfer Open	1.19E-06	0.00E+00	1.19E-08	0.00E+00

See Note 3.

Notes for Section 4 Tables

Note 1: f(OP) = Frequency of Overpressurization (/ry).
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
CDF = Core Damage Frequency (/ry).

Note 2: 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).

Note 3: AOV = Failure Rate of Air-Operated Check Valve (/ry).
MOV = Probability of MOV Failure.
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).

5. CORRECTIVE ACTIONS AND THEIR EFFECT ON CORE DAMAGE FREQUENCY

In this section, potential corrective actions for each of the three plants are discussed. The effect of these potential corrective actions on the frequency of overpressurization, the frequencies of LOCAs, and the frequency of core damage are also provided. Appendix H provides the results of a sensitivity study on the predicted core damage frequency benefits obtainable if a plant with no current leak testing requirements for its pressure isolation valves (PIVs) were to adopt some minimum frequency for PIV leak testing.

5.1 Corrective Actions for Peach Bottom

Three potential corrective actions were considered for Peach Bottom. They are described in this section. Table 5.1 summarizes the base case results listed in Tables 4.6 and 4.7. Tables 5.2 to 5.4 summarize the quantitative results if the corrective actions were separately implemented. Table 5.5 shows the results if all three corrective actions were implemented. The respective decreases in core damage frequency 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 could be detected and corrected, if a leak test were performed after each valve maintenance. The test could be either an LLRT or a PIV leak test. Table 5.2 shows the line-by-line results if this corrective action were to be 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 testing were not performed when the reactor is at power, the Browns Ferry type of incident would no longer apply to Peach Bottom. Table 5.3 shows the line by line results if the MOV failure mode of inadvertent opening were to be 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 (Section 4), it was assumed that the check valve failure would 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 were to be removed.

5.2 Corrective Actions for Nine Mile Point 2

Two potential corrective actions were 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 4.6 and 4.13. Tables 5.7 and 5.8 summarize the results given that the corrective actions would be separately implemented. Table 5.9 shows the results if both corrective actions would be implemented.

Tables 5.7 to 5.9 can be compared with Table 5.6 to determine the respective decreases in core damage frequency based upon the corrective actions.

5.2.1 Do Not Cycle Valves F052A(B) and F218A(B) at Power

Based on the analysis of Section 4, the dominant sequence 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 MOV in the lines fails open. Cycling of these valves at power makes these valves ineffective pressure barriers. If these valves are cycled only when the reactor is shut down, the dominant core damage scenario would be removed. Table 5.7 summarizes the line-by-line results if these MOVs were not cycled at power.

It was assumed that the Technical Specifications would be changed from once every 92 days to require testing while at shutdown if not tested in the last 92 days.

5.2.2 Do Not Cycle F087A(B) at Power

Valves F087A and F087B are cycled at power while 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 expected frequency of overpressurization and the frequency of core damage. Table 5.8 shows the line-by-line results if these valves were not cycled at power.

5.3 Corrective Actions for Quad Cities

Two potential corrective actions were considered for Quad Cities. They are described in this section. Table 5.10 summarizes the base case results listed in Table 4.6 and 4.20. Tables 5.11 and 5.12 summarize the quantitative results if the corrective actions were to be separately implemented. Table 5.13 summarizes the results if both corrective actions were 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 MOVs. Table 5.11 shows the line-by-line results for the corrective action of leak testing the air operated check valves every refueling.

Table 5.1
Summary of Results for Peach Bottom - Base Case

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.52E-03	2.65E-02	1.52E-05	7.06E-07	7.77E-07
CS	1.52E-03	5.52E-03	1.52E-05	1.15E-07	1.85E-07
HPCI	2.59E-03	9.34E-03	0.00E+00	2.64E-08	2.64E-08
RCIC	2.59E-03	1.74E-03	0.00E+00	4.91E-09	4.91E-09
Feedwater	1.00E-03	3.95E-03	0.00E+00	3.95E-06	4.42E-09
RHR Suction	7.71E-07	7.48E-02	7.52E-07	1.93E-08	2.27E-08
Vessel Head Spray	4.53E-08	2.65E-02	4.49E-08	4.01E-10	6.10E-10
Total	9.23E-03	---	3.12E-05	4.82E-06	1.02E-06

See Notes on page 5-9.

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

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	3.53E-05	2.65E-02	3.52E-07	1.58E-07	1.59E-07
CS	2.94E-05	5.52E-03	2.94E-07	3.25E-10	1.69E-09
HPCI	1.70E-03	9.34E-03	0.00E+00	1.29E-08	1.29E-08
RCIC	1.70E-03	1.74E-03	0.00E+00	2.40E-09	2.40E-09
Feedwater	1.00E-03	3.95E-03	0.00E+00	3.95E-06	4.42E-09
RHR Suction	7.71E-07	7.48E-02	7.52E-07	1.93E-08	2.27E-08
Vessel Head Spray	4.53E-08	2.65E-02	4.49E-08	4.01E-10	6.10E-10
Total	4.47E-03	---	1.44E-06	4.14E-06	2.04E-07

See Notes on page 5.9.

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	2.65E-02	1.32E-07	7.94E-08	8.01E-08
CS	1.18E-05	5.52E-03	1.18E-07	8.40E-09	8.95E-09
HPCI	1.68E-04	9.34E-03	0.00E+00	3.17E-09	3.17E-09
RCIC	1.68E-04	1.74E-03	0.00E+00	5.91E-10	5.91E-10
Feedwater	1.00E-03	3.95E-03	0.00E+00	3.95E-06	4.42E-09
RHR Suction	7.71E-07	7.48E-02	7.52E-07	1.93E-08	2.27E-08
Vessel Head Spray	4.53E-08	2.65E-02	4.49E-08	4.01E-10	6.10E-10
Total	1.36E-03	---	1.05E-06	4.06E-06	1.21E-07

See Notes on page 5.9.

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

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.52E-03	2.65E-02	1.52E-05	7.06E-07	7.77E-07
CS	1.52E-03	5.52E-03	1.52E-05	1.15E-07	1.85E-07
HPCI	2.40E-04	9.34E-03	0.00E+00	2.00E-09	2.00E-09
RCIC	2.40E-04	1.74E-03	0.00E+00	3.73E-10	3.73E-10
Feedwater	1.00E-03	3.95E-03	0.00E+00	3.95E-06	4.42E-09
RHR Suction	7.71E-07	7.48E-02	7.52E-07	1.93E-08	2.27E-08
Vessel Head Spray	4.53E-08	2.65E-02	4.49E-08	4.01E-10	6.10E-10
Total	4.52E-03	---	3.12E-05	4.79E-06	9.92E-07

See Notes on page 5.9.

Table 5.5
Summary of Results for Peach Bottom - All Corrective Actions

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	8.88E-06	2.65E-02	8.84E-08	3.95E-08	3.99E-08
CS	7.40E-06	5.52E-03	7.40E-08	8.15E-11	4.25E-10
HPCI	5.05E-06	9.34E-03	0.00E+00	7.59E-11	7.59E-11
RCIC	5.05E-06	1.74E-03	0.00E+00	1.41E-11	1.41E-11
Feedwater	1.00E-03	3.95E-03	0.00E+00	3.95E-06	4.42E-09
RHR Suction	7.71E-07	7.48E-02	7.52E-07	1.93E-08	2.27E-08
Vessel Head Spray	4.53E-08	2.65E-02	4.49E-08	4.01E-10	6.10E-10
Total	1.03E-03	---	9.59E-07	4.01E-06	6.82E-08

See Notes on page 5.9.

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	3.95E-03	7.98E-06	8.84E-09	9.97E-09
LPCS	3.69E-06	3.95E-03	2.22E-06	2.92E-11	3.43E-10
SDC Return	8.86E-06	3.95E-03	5.32E-06	5.89E-09	6.64E-09
HPCS	2.65E-07	2.65E-02	2.65E-07	8.61E-14	5.29E-11
Vessel Head Spray	4.35E-06	1.74E-03	5.05E-08	9.28E-13	2.21E-10
Feedwater	1.00E-03	1.03E-03	0.00E+00	1.03E-06	1.15E-09
RHR Suction	7.71E-07	1.58E-02	7.67E-07	4.07E-09	4.15E-09
Steam Condensing	8.89E-03	3.95E-03	4.40E-05	8.78E-06	8.78E-06
Total	9.92E-03	---	6.07E-05	9.83E-06	8.81E-06

See Notes on page 5.9.

Table 5.7
Summary of Results for Nine Mile Point-2 -
Do Not Cycle Valves F052A(B) and F218A(B) at Power

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.33E-05	3.95E-03	7.98E-06	8.84E-09	9.97E-09
LPCS	3.69E-06	3.95E-03	2.22E-06	2.92E-11	3.43E-10
SDC Return	8.86E-06	3.95E-03	5.32E-06	5.89E-09	6.64E-09
HPCS	2.65E-07	2.65E-02	2.65E-07	8.61E-14	5.29E-11
Vessel Head Spray	4.35E-06	1.74E-03	5.05E-08	9.28E-13	2.21E-10
Feedwater	1.00E-03	1.03E-03	0.00E+00	1.03E-06	1.15E-09
RHR Suction	7.71E-07	1.58E-02	7.67E-07	4.07E-09	4.15E-09
Steam Condensing	2.41E-03	3.95E-03	1.19E-05	2.38E-06	2.38E-06
Total	3.44E-03	---	2.85E-05	3.43E-06	2.40E-06

See Notes on page 5.9.

Table 5.8
Summary of Results for Nine Mile Point-2 -
Do Not Cycle Valves F087A(B) at Power

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.33E-05	3.95E-03	7.98E-06	8.84E-09	9.97E-09
LPCS	3.69E-06	3.95E-03	2.22E-06	2.92E-11	3.43E-10
SDC Return	8.86E-06	3.95E-03	5.32E-06	5.89E-09	6.64E-09
HPCS	2.65E-07	2.65E-02	2.65E-07	8.61E-14	5.29E-11
Vessel Head Spray	4.35E-06	1.74E-03	5.05E-08	9.28E-13	2.21E-10
Feedwater	1.00E-03	1.03E-03	0.00E+00	1.03E-06	1.15E-09
RHR Suction	7.71E-07	1.58E-02	7.67E-07	4.07E-09	4.15E-09
Steam Condensing	6.49E-03	3.95E-03	3.22E-05	6.41E-06	6.41E-06
Total	7.52E-03	---	4.88E-05	7.46E-06	6.44E-06

See Notes on page 5.9.

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

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.33E-05	3.95E-03	7.98E-06	8.84E-09	9.97E-09
LPCS	3.69E-06	3.95E-03	2.22E-06	2.92E-11	3.43E-10
SDC Return	8.86E-06	3.95E-03	5.32E-06	5.89E-09	6.64E-09
HPCS	2.65E-07	2.65E-02	2.65E-07	8.61E-14	5.29E-11
Vessel Head Spray	4.35E-06	1.74E-03	5.05E-08	9.28E-13	2.21E-10
Feedwater	1.00E-03	1.03E-03	0.00E+00	1.03E-06	1.15E-09
RHR Suction	7.71E-07	1.58E-02	7.67E-07	4.07E-09	4.15E-09
Steam Condensing	1.00E-05	3.95E-03	4.89E-08	9.71E-09	9.72E-09
Total	1.04E-03	---	1.67E-05	1.06E-06	3.22E-08

See Notes on page 5.9.

Table 5.10
Summary of Results for Quad Cities - Base Case

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	2.07E-03	9.34E-03	2.07E-05	5.60E-07	6.71E-07
CS	2.01E-03	3.95E-03	2.01E-05	1.20E-07	2.28E-07
HPCI	9.03E-04	9.34E-03	0.00E+00	8.79E-09	8.79E-09
RCIC	9.03E-04	1.74E-03	0.00E+00	1.64E-09	1.64E-09
Feedwater	1.00E-03	9.96E-03	0.00E+00	9.96E-06	1.12E-08
RHR Suction	7.71E-07	2.65E-02	7.64E-07	6.82E-09	1.09E-08
Vessel Head Spray	4.53E-08	9.34E-03	4.52E-08	1.41E-10	3.84E-10
Total	6.89E-03	---	4.16E-05	1.07E-05	9.32E-07

See Notes on page 5.9.

Table 5.11
Summary of Results for Quad Cities -
Leak Test AO Check Valves Each Refueling

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.50E-03	9.34E-03	1.50E-05	2.80E-08	1.08E-07
CS	1.50E-03	3.95E-03	1.50E-05	6.01E-09	8.62E-08
HPCI	7.43E-04	9.34E-03	0.00E+00	6.96E-09	6.96E-09
RCIC	7.43E-04	1.74E-03	0.00E+00	1.30E-09	1.30E-09
Feedwater	1.00E-03	9.96E-03	0.00E+00	9.96E-06	1.12E-08
RHR Suction	7.71E-07	2.65E-02	7.64E-07	6.82E-09	1.09E-08
Vessel Head Spray	4.53E-08	9.34E-03	4.52E-08	1.41E-10	3.84E-10
Total	5.48E-03	---	3.08E-05	1.00E-05	2.25E-07

See Notes on page 5.9.

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

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.87E-03	9.34E-03	1.87E-05	2.79E-07	3.79E-07
CS	1.81E-03	3.95E-03	1.81E-05	1.17E-09	9.80E-08
HPCI	8.02E-04	9.34E-03	0.00E+00	7.14E-09	7.14E-09
RCIC	8.02E-04	1.74E-03	0.00E+00	1.33E-09	1.33E-09
Feedwater	1.00E-03	9.96E-03	0.00E+00	9.96E-06	1.12E-08
RHR Suction	7.71E-07	2.65E-02	7.64E-07	6.82E-09	1.09E-08
Vessel Head Spray	4.53E-08	9.34E-03	4.52E-08	1.41E-10	3.84E-10
Total	6.28E-03	---	3.76E-05	1.03E-05	5.08E-07

See Notes on page 5.9.

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

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.49E-03	9.34E-03	1.49E-05	1.39E-08	9.38E-08
CS	1.49E-03	3.95E-03	1.49E-05	5.83E-11	7.97E-08
HPCI	7.38E-04	9.34E-03	0.00E+00	6.88E-09	6.88E-09
RCIC	7.38E-04	1.74E-03	0.00E+00	1.28E-09	1.28E-09
Feedwater	1.00E-03	9.96E-03	0.00E+00	9.96E-06	1.12E-08
RHR Suction	7.71E-07	2.65E-02	7.64E-07	6.82E-09	1.09E-08
Vessel Head Spray	4.53E-08	9.34E-03	4.52E-08	1.41E-10	3.84E-10
Total	5.45E-03	---	3.06E-05	9.99E-06	2.04E-07

See Notes below.

<u>Notes for Section 5 Tables</u>

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).

6. REGULATORY ANALYSIS

6.1 Introduction

This entire section of the report is formatted according to the guidelines of NUREG/BR-0058, Regulatory Analysis Guidelines of the USNRC.[1]

Statement of Problem

A number of overpressurization events have occurred at operating BWR nuclear power plants. To date, none have led to severe consequences. The concern is, however, that such events represent precursors to interfacing system LOCAs (ISLs). Probabilistic Risk Assessments (PRAs) have shown that the expected frequency of core damage due to an ISL is typically a few percent or less of the overall core damage frequency. Even though low in predicted frequency, ISLs can be expected to be major contributors to the risk associated with core melt accidents.

Objectives

The primary objective of this study is to investigate in detail the interfacing LOCA at boiling water reactors. As stated above, ISLs have been estimated to be very low contributors to overall core damage frequency in previous PRAs and may therefore not have received the in-depth analysis they deserve. Two further objectives are to investigate improved leak testing schemes for the pressure isolation valves to lower the frequency of overpressurization events and to find any key potential improvements based upon the three reference plants that would significantly aid in further reducing the frequency of ISLs on a generic basis for the BWR population.

Alternatives

In order to provide a range of alternatives within the study, four models representing three actual plants and one derived generic plant were investigated. The investigation of the generic plant focused only on what would be the cost-benefit consideration in requiring that leak testing be performed. The three reference plants were also investigated as to possible improvements in their PIV leak testing requirements. In addition, the reference plants were investigated for other possible improvements that could further reduce their specific vulnerabilities to overpressurization events and ISLs. A number of alternative actions have been identified for each of the models and the actions vary among the models. All proposed actions have undergone a cost-benefit analysis documented in the following subsections.

Consequences

There are three basic concerns to be considered in the consequence analysis for any proposed corrective actions. These concerns are the cost-benefit considerations, the potential impact on other NRC requirements, and any constraint that may have to be placed upon the implementation of a given proposed corrective action. The cost-benefit considerations are discussed in detail in the following subsection and impact on other requirements is addressed in the succeeding subsections. In terms of constraints (as defined in NUREG/BR-0058),

we have not identified any such considerations that would impact the proposed corrective actions.

6.2 Cost-Benefit Considerations

Approach for Determining Costs

The implementation of the corrective actions discussed in Section 5 requires revisions of existing procedures, development of new procedures, revisions of the ISI program or the Technical Specifications, and the execution of any new procedures. In order to obtain accurate estimates of the costs involved and to solicit comments on the study, copies of the first five sections of this report were sent to the reference plants and the utility companies that own the plants. Written responses were received and are included in Appendix G.

This section describes the costs involved in implementing each of the proposed corrective actions for each reference plant. Cost estimates are based on the information from the plants. Tables 6.1 to 6.3 summarize the cost-benefit analysis for each of the plants. The costs and benefits are expressed in units of dollars. A man-rem is assumed to be equivalent to \$1000.[2] An acute fatality is assumed to be equivalent to \$5,000,000.[3] Costs that recur over the years, e.g., costs of performing leak tests, are discounted using a discount rate of 10% per year[1] to determine their present value.

Approach for Determining Benefits

Benefits are divided into two major categories, i.e., those derived from lowering the predicted core damage frequency and those associated with lowering the frequency of overpressurization events. The latter category does not lead to core damage but does result in replacement power costs, clean up costs, and occupational doses. The reduction in core damage frequency and the reduction in overpressurization frequency are calculated using the results of Section 5 and Appendix H. They are expressed in units of per calendar year.

The CRAC2 code[4-5] was used to estimate the consequences of a LOCA event which bypasses containment. The details of this portion of the analysis are found in Appendix I. Two CRAC2 runs were made. The first assumes a release without the benefit of being submerged and the second includes the benefit of a submerged release. A decontamination factor of 10 was applied to all but the noble gases in the submerged case. These two runs are considered to bound the public health effects.

As discussed previously, the goal of this study is to provide a generic perspective to interfacing LOCAs at boiling water reactors. To that end, this regulatory analysis is being based upon a so-called generic 1000 Mw BWR situated on a generic site within the United States. In the following four subsections, we will assign the attributes that we have developed for the Peach Bottom plant, the Nine Mile Point 2 plant, the Quad Cities plant, and a base-case plant respectively.

Because we are looking at a generic plant with four sets of attributes, a number of the inputs for calculating the benefits will not change. The two CRAC2 runs that were made were based upon the power level of the Peach Bottom

reactor (1065 Mw). These results will be appropriately scaled down to the generic 1000 Mw plant.

The following items will be constant for the succeeding four cases given an ISL resulting in core damage:

- Public Health Effects
  Nonsubmerged Release
  (3.26×10^6 man-rem) (\$1000/man-rem) = $\$3.26 \times 10^9$ (1000/1065) = $\$3.06 \times 10^9$
  (5.9 acute fatalities) (5×10^6/acute fatality) = 2.95×10^7 (1000/1065) = $\$2.77 \times 10^7$

  Submerged Release
  (1.51×10^6 man-rem) (\$1000/man-rem) = $\$1.51 \times 10^9$ (1000/1065) = $\$1.42 \times 10^9$
  Zero acute fatalities = \$0.0

- Occupational Health Effects (Best estimates of Ref. 2)
  Immediate Dose (1000 man-rem) (\$1000/man-rem) = $\$10^6$
  Long-Term Dose (20,000 man-rem) (\$1000/man-rem) = $\$2 \times 10^7$

- Onsite Cleanup Costs (Estimated based on TMI experience[6])
  1×10^8/year for 10 years

- Land Interdiction w/o Decontamination
  Nonsubmerged Release $\$1.76 \times 10^9$ (1000/1065) = $\$1.65 \times 10^9$
  Submerged Release $\$3.69 \times 10^8$ (1000/1065) = $\$3.45 \times 10^8$

Concept of Discounting

In evaluating the economic consequences of a potential accident that can occur any time in the life of a plant, we must sum terms for costs occurring over a period of many years. This creates a problem because a dollar today is not of the same value as a dollar in the future. One way to compare dollars that arrive at different points in time is to find the amount of money which must be placed in a bank today to have the same amount of money at the time the other money is scheduled to arrive. The sum of money which must be put in the bank today to achieve a specific sum at a point in the future is called the discounted present value of the later sum, and the interest rate is called the discount rate. The following discounting formulas are taken from Ref. 7. They are applicable to different types of consequences or costs of an accident.

Consequences that the formula applies to:

$C_o f \frac{1-e^{-rt_f}}{r}$ Health effects, offsite property damage. (6.1)

$\frac{C_o f}{r^2} (1-e^{-rt_f}) (1-e^{-rt_M})$ Cleanup expense. (6.2)

$\frac{C_o f}{r} (\frac{1-e^{-rt_f}}{r} - e^{-rt_f} t_f)$ Replacement power. (6.3)

where C_o = present cost of a consequence
f = frequency of accident
t_f = end of plant life
r = discount rate
M = duration of an expense that recurs for several years.

Basically, the formulas are used to determine the multiplier of C_of. For example, in the case of a core damage accident, a cleanup expense of $100,000,000 per year for 10 years is comparable to current estimates of the cleanup costs for the TMI accident.[6] For a plant with 30 years of remaining plant life, the discounted cost of cleanup over 30 years can be calculated using the second formula, i.e.,

$$\frac{100 * 10^6 * f}{0.1^2} (1-e^{-0.1*30}) (1-e^{-0.1*10}) = 6x10^9 * f = 60 * C_o f$$

where the discount rate is taken to be 0.1 which is the suggested value by the Regulatory Analysis Guideline.[1]

6.2.1 Peach Bottom Model

6.2.1.1 Costs

Very detailed written cost and occupational dose estimates were provided by Peach Bottom personnel. These are included in Appendix G.1. They were used to calculate the average annual costs for the proposed corrective actions.

Leak Test Air-Operated Check Valves After Maintenance

This corrective action affects six air-operated check valves (in the RHR, CS, RCIC, and HPCI systems). It requires development of test procedures for RCIC and HPCI, and performance of the leak tests as required. The Peach Bottom input stated that the check valves in the RHR and CS systems are containment isolation valves and are subject to 10CFR50 Appendix J requirements. The associated test procedures have already been written. Therefore, no cost is assumed. It has been estimated in Appendix G.1 that 480 man-hours would be required to write, review, approve, type, duplicate, and distribute new test procedures for HPCI and RCIC. It is also estimated in Appendix G.1 that the cost of a man-hour is approximately $40. Therefore, the total cost for development of test procedures is $19,200. It is also estimated in Appendix G.1 that each testable check valve will be maintained once every two years, and the cost for performing the tests is 166 man-hours and 2.05 man-rem. On the average, the annual cost of performing the tests is 83 man-hours and 1.025 man-rem, or equivalently, $4345.

Discounting the annual costs by Equation 6.1 with $r=.1$ and $t_f=30$
= $4345 * 9.5 = $41,278
Total cost = $19,200 + $41,278 = $60,478.

Perform Logic System Functional Tests During Shutdown

Logic system functional tests for the ECCS are currently performed once every six months when the reactor is at power. One proposed change is to perform the tests at every refueling and thus preclude the additional risk of overpressurization. Information from the plant (Appendix G.1) indicates that testing of HPCI and RCIC requires reactor steam, in particular, power level above 9% is required for testing HPCI. Section 5 of this report indicates that the reduction in core damage frequency for Peach Bottom mainly came from testing the RHR and CS systems at shutdown. Therefore, cost estimates for performing logic system functional testing of RHR and CS systems are the only changes proposed. Three types of costs are considered in Appendix G.1, 1) procedure revision for the logic system functional tests, 2) Technical Specification changes, and 3) additional manpower required to perform the tests. The first two are one time costs and are estimated to be 1920 man-hours ($76,800) and $18,000, respectively. The cost due to additional manpower needed is estimated to be 32 man-hours and .048 man-rem per test. Assuming refueling is performed once every 18 months, the additional cost for testing is 21 man-hours and 0.32 man-rem per year, or equivalently $1173 per year.

Discounting the annual costs by Equation 6.1 = $\$1173*9.5 = \$1.11\text{x}10^4$
Total cost = $76,800 + $18,000 + $11,000 = $105,900.

Leak Test HPCI and RCIC Testable Check Valves Every Refueling

This proposed corrective action requires development of test procedures and performance of the tests. The cost for the development of procedures is estimated above to be $19,200. The cost for performing the tests is estimated in Appendix G.1 to be 70 man-hours and 0.625 man-rem per test, or equivalently $2283 per year.

Discounting the annual costs by Equation 6.1
= $2283 * 9.5 = $21,700
Total costs = $19,200 + $21,700 = $40,900.

Implementation of All Three Peach Bottom Corrective Actions

The cost for implementing all three corrective actions is the sum of the costs for the three corrective actions minus the duplicated cost for development of test procedures for the air-operated check valves of RCIC and HPCI as two of the corrective actions cover the same procedures. That is,

$$\$60,478 + \$105,900 + \$40,900 - \$19,200 = \$188,078$$

6.2.1.2 Benefits

For core damage events, the benefit of a reduction in core damage frequency can be expressed as follows:

$$\text{Benefit}_{CD} = \Delta f_{CD} \text{ (man rem + replacement power + cleanup costs + land interdiction)}$$

Replacement power costs are dependent upon the region of the United States in which the plant is located.[2] For the Peach Bottom region, replacement power costs on a yearly basis for a 1000 Mw plant would be:

$$[(0.13 * 0.5) + 0.12] * \$10^6/\text{Mw year} * 1000\ \text{Mw} = \$1.85\text{x}10^8/\text{year}$$

Discounting the various benefits yields the following:

- Public Health + Occupational Health
  (Nonsubmerged Case)
  $\$3.06\text{x}10^9 + \$2.77\text{x}10^7 + \$10^6 + \$2\text{x}10^7 = \$3.11\text{x}10^9$/accident
  Discounting using Equation 6.1 (with $r=0.1$, $t_f=30$) = 9.5
  $\$3.11\text{x}10^9 * 9.5 = \$2.95\text{x}10^{10}$

  (Submerged Case)
  $\$1.42\text{x}10^9$ + Zero + $\$10^6 + \$2\text{x}10^7 = \$1.44\text{x}10^9$/accident
  $\$1.44\text{x}10^9 * 9.5 = \$1.37\text{x}10^{10}$

- Replacement Power - $\$1.85\text{x}10^8$/year
  Discounting using Equation 6.3 ($r=0.1$, $t_f=30$) = 80.1
  $\$1.85\text{x}10^8 * 80.1 = \$1.48\text{x}10^{10}$

- Cleanup Costs - $\$10^8$ for 10 years
  Discounting using Equation 6.2 ($r=0.1$, $t_f=30$, $t_m=10$) = 60.06
  $\$1\text{x}10^8 * 60.06 = \$6.01\text{x}10^9$

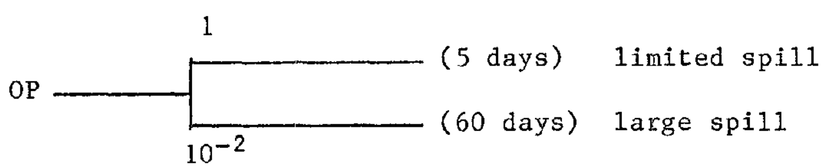
- Land Interdiction
  Discounting using Equation 6.1 → 9.5
  (Nonsubmerged Case)
  $\$1.65\text{x}10^9 * 9.5 = \$1.57\text{x}10^{10}$

  (Submerged Case)
  $\$3.45\text{x}10^8 * 9.5 = \$3.28\text{x}10^9$

For overpressurization events that result in the introduction of primary coolant outside the containment but without core damage, the benefit of a reduction in the frequency of overpressurization can be expressed as follows:

$$\text{Benefit}_{OP} = \Delta f_{OP} * (\text{replacement power costs})$$

Other costs have not been included because the replacement power costs totally dominate this type of event. We have broken this category of events into two parts. One part addressing events that are isolated rather quickly and thus limit the spill and the other part addressing those that are not isolated until the spill represents hundreds of thousands of gallons of primary coolant. Our model is shown as follows:



$$\left[(0.13 * .5) + 0.12\right] \$10^6/\text{Mw year} * 1000 \text{ Mw} * 5 \text{ days} = \$2.53\text{x}10^6$$
$$\left[(0.13 * .5) + 0.12\right] \$10^6/\text{Mw year} * 1000 \text{ Mw} * 60 \text{ days} = \$3.04\text{x}10^7$$

$\text{Benefit}_{OP} = 2.53\text{x}10^6 + (10^{-2} * 3.04\text{x}10^7) = \$2.83\text{x}10^6/\text{OP}$
Discounting using Equation 6.1
$\$2.83\text{x}10^6/\text{OP} * 9.5 = \$2.72\text{x}10^7$

The overall benefit of the design changes can be calculated based upon the foregoing input as follows:

$\text{Benefit}_{TOT} = \Delta f_{CD}$ (man rem + replacement power + cleanup + land interdiction) + Δf_{OP} (replacement power)

(For Nonsubmerged Case)
$$= \Delta f_{CD}\,(2.95\text{x}10^{10} + 1.48\text{x}10^{10} + 6.01\text{x}10^9 + 1.57\text{x}10^{10}) + \Delta f_{OP}\,(2.72\text{x}10^7)$$
$$= \Delta f_{CD} * 6.60\text{x}10^{10} + \Delta f_{OP} * 2.72\text{x}10^7$$

(For Submerged Case)
$$= \Delta f_{CD}\,(1.37\text{x}10^{10} + 1.48\text{x}10^{10} + 6.01\text{x}10^9 + 3.28\text{x}10^9) + \Delta f_{OP}\,(2.72\text{x}10^7)$$
$$= \Delta f_{CD} * 3.78\text{x}10^{10} + \Delta f_{OP} * 2.72\text{x}10^7$$

6.2.1.3 Results

There are three proposed corrective actions as well as a fourth which includes all three from Section 5 based upon the Peach Bottom design, namely:

1. Leak test air-operated check valves after maintenance.
2. Perform logic system functional tests during shutdown.
3. Leak tests HPCI and RCIC testable check valves every refueling.
4. Implementation of all of the above.

The estimated risk-based costs and benefits for the above four corrective actions are presented in Table 6.1. Section 7.1 provides a discussion on these results.

6.2.2 Nine Mile Point-2 Model

6.2.2.1 Costs

The proposed corrective actions for Nine Mile Point-2 require changes in the ISI program so that the pressure isolation valves in the steam condensing line will not be cycled when the reactor is at power. The response from Nine Mile Point-2 (Appendix G.2), indicates that the proposed corrective actions have been identified by the plant through independent means, and have also been included in a recent ISI program revision submitted to NRC. Therefore, no actual additional cost would be incurred by NMP-2 for this proposed corrective action. However, for the purposes of this study, Nine Mile Point-2 did provide a cost estimate that $35,000 would be needed to implement all aspects of the proposed corrective actions, if these corrective actions would have been initiated and accomplished as a direct response to the results of this study.

6.2.2.2 Benefits

For core damage events, the benefit of a reduction in core damage frequency can be expressed as follows:

$\text{Benefit}_{CD} = \Delta f_{CD}$ (man rem + replacement power + cleanup costs + land interdiction)

Replacement power costs are dependent upon the region of the United States in which the plant is located. For the Nine Mile Point region replacement power costs on a yearly basis for a 1000 Mw plant would be:

$[(0.13 * 0.95) + 0.12] * \$10^6/\text{Mw year} * 1000\text{ Mw} = \$2.44\text{x}10^8/\text{year}$

Discounting the various benefits yields the following:

- Public Health + Occupational Health
  (Nonsubmerged Case)
  $\$3.06\text{x}10^9 + \$2.77\text{x}10^9 + \$10^6 + \$2\text{x}10^7 = \$3.11\text{x}10^9$/accident
  Discounting using Equation 6.1 (with $r=0.1$, $t_f=40$) = 9.82
  $\$3.11\text{x}10^9 * 9.82 = \$3.05\text{x}10^{10}$

  (Submerged Case)
  $\$1.42\text{x}10^9$ + Zero + $\$10^6 + \$2\text{x}10^7 = \$1.44\text{x}10^9$/accident
  $\$1.44\text{x}10^9 * 9.82 = \$1.41\text{x}10^{10}$

- Replacement Power - $\$1.85\text{x}10^8$/year
  Discounting using Equation 6.3 ($r=0.1$, $t_f=40$) = 90.8
  $\$2.44\text{x}10^8 * 90.8 = \$2.22\text{x}10^{10}$

- Cleanup Costs - $\$10^8$ for 10 years
  Discounting using Equation 6.2 ($r=0.1$, $t_f=40$, $t_m=10$) = 62.1
  $\$1\text{x}10^8 * 62.1 = \$6.21\text{x}10^9$

- Land Interdiction
  Discounting using Equation 6.1 $\rightarrow$ 9.82
  (Nonsubmerged Case)
  $\$1.65\text{x}10^9 * 9.82 = \$1.62\text{x}10^{10}$

  (Submerged Case)
  $\$3.45\text{x}10^8 * 9.82 = \$3.39\text{x}10^9$

For overpressurization events that result in the introduction of primary coolant outside the containment but without core damage, the benefit of a reduction in the frequency of overpressurization can be expressed as follows:

$\text{Benefit}_{OP} = \Delta f_{OP}$ * (replacement power costs)

Other costs have not been included because the replacement power costs totally dominate this type of event. We have broken this category of events into two parts. Using the model described in Section 6.2.1.2 we have the following:

$$\left[(0.13 * .95) + 0.12\right] \$10^6/\text{Mw year} * 1000 \text{ Mw} * 5 \text{ days} = \$3.34\text{x}10^6$$
$$\left[(0.13 * .95) + 0.12\right] \$10^6/\text{Mw year} * 1000 \text{ Mw} * 60 \text{ days} = \$4.0\text{x}10^7$$

$\text{Benefit}_{OP} = 3.34\text{x}10^6 + (10^{-2} * 4.0\text{x}10^7) = \$3.74\text{x}10^6/\text{OP}$
Discounting using Equation 6.1
$\$3.74\text{x}10^6/\text{OP} * 9.82 = \$3.67\text{x}10^7$

The overall benefit of the design changes can be calculated based upon the foregoing input as follows:

$\text{Benefit}_{TOT} = \Delta f_{CD}$ (man rem + replacement power + cleanup + land interdiction) + Δf_{OP} (replacement power)

(For Nonsubmerged Case)
$$= \Delta f_{CD}\,(3.05\text{x}10^{10} + 2.22\text{x}10^{10} + 6.21\text{x}10^9 + 1.62\text{x}10^{10}) + \Delta f_{OP}\,(3.67\text{x}10^7)$$
$$= \Delta f_{CD} * 7.51\text{x}10^{10} + \Delta f_{OP} * 3.67\text{x}10^7$$

(For Submerged Case)
$$= \Delta f_{CD}\,(1.41\text{x}10^{10} + 2.22\text{x}10^{10} + 6.21\text{x}10^9 + 3.39\text{x}10^9) + \Delta f_{OP}\,(3.67\text{x}10^7)$$
$$= \Delta f_{CD} * 4.59\text{x}10^{10} + \Delta f_{OP} * 3.67\text{x}10^7$$

6.2.2.3 Results

There are two proposed corrective actions as well as a third which includes both from Section 5 based upon the Nine Mile Point Unit 2 design, namely:

1. Do not cycle the F052 valve group and the F218 valve group at power.
2. Do not cycle the F087 valve group at power.
3. Implementation of both of the above.

The estimated risk-based costs and benefits for the above corrective actions are presented in Table 6.2. Section 7.2 provides a discussion on these results.

6.2.3 Quad Cities Model

6.2.3.1 Costs

The proposed corrective actions for Quad Cities are similar to those proposed for Peach Bottom. Therefore, some of the cost estimates for Peach Bottom have also been directly applied to Quad Cities. In addition, Commonwealth Edison provided an estimate for the cost of installing test taps to the core spray lines (Appendix G.3).

Leak Test Air-Operated Check Valves Every Refueling

This potential corrective action involves installing the test taps, developing the test procedures, obtaining approval for changes in the ISI program, and actually performing the tests. Appendix G.3 estimated that the cost of installing test taps to the core spray lines is \$40,400. Peach Bottom estimated that it requires 480 man-hours for developing test procedures for RCIC and HPCI. BNL has assumed that an equal amount of time would be needed for the

RHR and CS systems. Therefore, 960 man-hours or equivalently $38,400 would be needed for procedure development. The cost for revision of the ISI program was assumed to be the same as that for Nine Mile Point-2, i.e., $35,000. Based on our plant visit and subsequent telephone conversations with Quad Cities, the man-hours needed to perform a leak test are estimated to be eight man-hours. Therefore, 48 man-hours would be required to perform leak tests on six valves. Peach Bottom estimated that 2.05 man-rem would be received while testing the valves. This same estimate was used for Quad Cities. Therefore, every refueling 48 man-hours and 2.05 man-rem would be consumed to leak test the testable check valves. It was estimated for Peach Bottom (Appendix G.1) that 25% of the time the valve may fail the test and require maintenance and a second leak test. Therefore, these values were increased by 25% to 60 man-hours and 2.56 man-rem. This is equivalent to $3307 per year.

Discounting the annual costs by Equation 6.1 with $r=0.1$ and $t_f=30$
= $3307 * 9.5 = $31,400
Total costs = $31,400 + $38,400 + $40,400 + $35,000 = $145,200.

Leak Test Air-Operated Check Valves After Maintenance

The cost for this corrective action is the same as that for the corrective action discussed above, except that the frequency of testing is lower than once per refueling. Peach Bottom estimated that maintenance is performed once every two years. Therefore, the average cost for performing the test is 24 man-hours and 1.025 man-rem per year, or equivalently $1985 per year.

Discounting the annual costs by Equation 6.1 → 9.5
= $1985 * 9.5 = $18,858
Total costs = $18,858 + $38,400 + $40,400 + $35,000 = $132,658.

Implementation of Both Quad Cities Corrective Actions

The cost for implementing both proposed corrective actions is equal to the cost of implementing the first corrective action plus the cost of performing the tests required by the second corrective action, i.e.,

$145,200 + $18,858 = $164,058

6.2.3.2 Benefits

For core damage events, the benefit of a reduction in core damage frequency can be expressed as follows:

$$\text{Benefit}_{CD} = \Delta f_{CD} \text{ (man rem + replacement power + cleanup costs + land interdiction)}$$

Replacement power costs are dependent upon the region of the United States in which the plant is located. For the Quad Cities region, replacement power costs on a yearly basis for a 1000 Mw plant would be:

$$[(0.13 * 0.15) + 0.12] * \$10^6/\text{Mw year} * 1000 \text{ Mw} = \$1.4\text{x}10^8/\text{year}$$

Discounting the various benefits yields the following:

- Public Health + Occupational Health
  (Nonsubmerged Case)
  $\$3.06x10^9 + \$2.77x10^7 + \$10^6 + \$2x10^7 = \$3.11x10^9$/accident
  Discounting using Equation 6.1 (with $r=0.1$, $t_f=30$) = 9.5
  $\$3.11x10^9 * 9.5 = \$2.95x10^{10}$

  (Submerged Case)
  $\$1.42x10^9$ + Zero + $\$10^6 + \$2x10^7 = \$1.44x10^9$/accident
  $\$1.44x10^9 * 9.5 = 1.37x10^{10}$

- Replacement Power - $\$1.4x10^8$/year
  Discounting using Equation 6.2 ($r=0.1$, $t_f=30$) = 80.1
  $\$1.4x10^8 * 80.1 = \$1.12x10^{10}$

- Cleanup Costs - $\$10^8$ for 10 years
  Discounting using Equation 6.3 ($r=0.1$, $t_f=30$, $t_m=10$) = 60.06
  $\$1x10^8 * 60.06 = \$6.01x10^9$

- Land Interdiction
  Discounting using Equation 6.1 $\rightarrow$ 9.5
  (Nonsubmerged Case)
  $\$1.65x10^9 * 9.5 = \$1.57x10^{10}$

  (Submerged Case)
  $\$3.45x10^8 * 9.5 = \$3.28x10^9$

For overpressurization events that result in the introduction of primary coolant outside the containment but without core damage, the benefit of a reduction in the frequency of overpressurization can be expressed as follows:

$$\text{Benefit}_{OP} = \Delta f_{OP} * \text{(replacement power costs)}$$

Other costs have not been included because the replacement power costs totally dominate this type of event. We have broken this category of events into two parts. Using the model described in Section 6.2.1.2, we have the following:

$$\left[(0.13 * .15) + 0.12\right] \$10^6/\text{Mw year} * 1000 \text{ Mw} * 5 \text{ days} = \$1.91x10^6$$
$$\left[(0.13 * .15) + 0.12\right] \$10^6/\text{Mw year} * 1000 \text{ Mw} * 60 \text{ days} = \$2.29x10^7$$

$\text{Benefit}_{OP} = \$1.91x10^6 + (10^{-2} * \$2.29x10^7) = \$2.14x10^6/OP$
Discounting using Equation 6.1
$\$2.14x10^6/OP * 9.5 = 2.03x10^7$

The overall benefit of the design changes can be calculated based upon the foregoing input as follows:

$$\text{Benefit}_{TOT} = \Delta f_{CD} \text{ (man rem + replacement power + cleanup + land interdiction)} + \Delta f_{OP} \text{ (replacement power)}$$

(For Nonsubmerged Case)

$$= \Delta f_{CD} (2.95\text{x}10^{10} + 1.12\text{x}10^{10} + 6.01\text{x}10^{9} + 1.57\text{x}10^{10}) + \Delta f_{OP} (2.03\text{x}10^{7})$$

$$= \Delta f_{CD} * 6.24\text{x}10^{10} + \Delta f_{OP} * 2.03\text{x}10^{7}$$

(For Submerged Case)

$$= \Delta f_{CD} (1.37\text{x}10^{10} + 1.12\text{x}10^{10} + 6.01\text{x}10^{9} + 3.28\text{x}10^{9}) + \Delta f_{OP} (2.03\text{x}10^{7})$$

$$= \Delta f_{CD} * 3.42\text{x}10^{10} + \Delta f_{OP} * 2.03\text{x}10^{7}$$

6.2.3.3 Results

There are two proposed corrective actions as well as third which includes both from Section 5 based upon the Quad Cities design, namely:

1. Leak test air-operated check valves every refueling.
2. Leak test air-operated check valves after maintenance.
3. Implementation of all of the above.

The estimated risk-based costs and benefits for the above corrective actions are presented in Table 6.3. Section 7.3 provides a discussion on these results.

6.2.4 Base Case Model

As discussed previously, the three reference plants selected for this study all perform some level of leak testing for their pressure isolation valves. One of the major goals of this study was to determine the cost-benefit relationship of requiring a plant that does not perform leak testing of its PIVs to do so. NRC guidance in defining this base case included the provision that those plants which voluntarily test their PIVs but are not required to, would fall into this category.

In order to construct a base case plant, we took the Peach Bottom model that we had developed and modified it to reflect the fact that leak testing of the PIVs is simply not performed. The details of this model are discussed in Appendix H. The reductions in the frequency of core damage and the frequency of overpressurization, as a result of leak testing the PIVs, were also evaluated in Appendix H.

6.2.4.1 Costs

The various costs for performing leak tests of the air-operated check valves can be estimated using those estimated for the three reference plants. Appendix G.3 estimated that the cost of installing test taps to the core spray lines of Quad Cities would be \$40,400. Therefore, a total cost of \$121,200 was assumed to be needed for installing test taps to the six ECCS injection lines. Appendix G.1 estimated that 480 man-hours would be needed to write, review, approve, type, duplicate, and distribute new test procedures for HPCI and RCIC. Therefore, it was assumed that twice as much would be needed to do the same thing for CS, LPCI, RCIC, and HPCI, i.e., 960 man-hours or equivalently \$$3.84*10^{4}$. The costs for leak testing air-operated check valves after maintenance and at every refueling outage had been estimated for Quad Cities to

be \$1985 per year and \$3307 per year, respectively and these valves are also used in the base case model.

Discounting the annual costs by Equation 6.1 ($r=0.1$, $t_f=30$) → 9.5
(\$1985 + \$3307) * 9.5 = \$50,274
Total costs = \$121,200 + \$38,400 + \$50,274 = $\$2.1*10^5$

6.2.4.2 Benefits

By assuming that the base case plant physically resembles Peach Bottom, we are able to use the two benefit equations developed in Section 6.2.1. These two equations are:

(Nonsubmerged Case)
$\text{Benefit}_{TOT} = \Delta f_{CD} * 7.18\text{x}10^{10} + \Delta f_{OP} * 2.72\text{x}10^{7}$

(Submerged Case)
$\text{Benefit}_{TOT} = \Delta f_{CD} * 3.78\text{x}10^{10} + \Delta f_{OP} * 2.72\text{x}10^{7}$

6.2.4.3 Results

The risk-based cost and benefits for leak testing air-operated check valves after maintenance and at every refueling outage are presented in Table 6.4. Section 7.4 provides a discussion on these results.

6.3 Impact on Other Requirements

We have not identified any NRC requirements or ongoing programs that would be adversely affected by implementation of any of the proposed corrective actions identified by this study.

We have identified two NRC programs that would be impacted. The two programs are the In-Service Testing and Inspection Program and the Technical Specifications. In each case, the impact would be to simply add certain pressure isolation valves to the existing programs.

6.4 References

1. "Regulatory Analysis Guidelines of the U.S. Nuclear Regulatory Commission," NUREG/BR-0058, January 1983.

2. S. W. Heaberlin et al., "A Handbook for Valve Impact Assessment," NUREG/CR-3568, December 1983.

3. ACRS, "An Approach to Quantitative Safety Goals for Nuclear Power Plants," NUREG -0739, October 1980.

4. Ritchie, L. T. et al., "Calculations of Reactor Accident Consequences Version 2.CRAC2: Computer Code User's Guide," NUREG/CR-2326, February 1983.

5. Ritchie, L. T. et al., "CRAC2 Model Description," NUREG/CR-2552, March 1984.

6. USGAO, Three Mile Island: The Financial Fallout, EMD-80-89, July 1980.

7. David R. Strip, "Estimates of the Financial Consequences of Nuclear Power Reactor Accidents," NUREG/CR-2723, September 1982.

Table 6.1
Cost-Benefit Estimates Based Upon the Peach Bottom Design

	Corrective Actions			
	1	2	3	4
Δf_{CD} (per calendar year)	$8.16x10^{-7}$	$8.99x10^{-7}$	$2.80x10^{-8}$	$9.52x10^{-7}$
Δf_{OP} (per calendar year)	$4.76x10^{-3}$	$7.87x10^{-3}$	$4.71x10^{-3}$	$8.20x10^{-3}$
Benefits				
Nonsubmerged Release	$\$1.83x10^{5}$	$\$2.73x10^{5}$	$\$1.30x10^{5}$	$\$2.86x10^{5}$
Submerged Release	$\$1.60x10^{5}$	$\$2.48x10^{5}$	$\$1.29x10^{5}$	$\$2.59x10^{5}$
Costs	$\$6.05x10^{4}$	$\$1.06x10^{5}$	$\$4.09x10^{4}$	$\$1.9x10^{5}$

Table 6.2
Cost-Benefit Estimates Based Upon the Nine Mile Point 2 Design

	Corrective Actions		
	1	2	3
Δf_{CD} (per calendar year)	$6.41x10^{-6}$	$2.37x10^{-6}$	$8.78x10^{-6}$
Δf_{OP} (per calendar year)	$6.48x10^{-3}$	2.4010^{-3}	$8.88x10^{-3}$
Benefits			
Nonsubmerged Release	$\$7.19x10^{5}$	$\$2.66x10^{5}$	$\$9.85x10^{5}$
Submerged Release	$\$5.32x10^{5}$	$\$1.97x10^{5}$	$\$7.29x10^{5}$
Costs			$\$3.5x10^{4}$

Table 6.3
Cost-Benefit Estimates Based Upon the Quad Cities Design

	Corrective Actions		
	1	2	3
Δf_{CD}	7.07×10^{-7}	4.24×10^{-7}	7.28×10^{-7}
Δf_{OP}	1.41×10^{-3}	6.10×10^{-4}	1.44×10^{-3}
<u>Benefits</u>			
Nonsubmerged Release	$\$7.27 \times 10^{4}$	$\$3.88 \times 10^{4}$	$\$7.47 \times 10^{4}$
Submerged Release	$\$5.28 \times 10^{4}$	$\$2.69 \times 10^{4}$	$\$5.41 \times 10^{4}$
<u>Costs</u>	$\$1.45 \times 10^{5}$	$\$1.33 \times 10^{5}$	$\$1.64 \times 10^{5}$

Table 6.4
Cost-Benefit Estimates Based Upon the Base Case Design

	Corrective Action
	1
Δf_{CD}	1.84×10^{-5}
Δf_{OP}	1.13×10^{-2}
<u>Benefits</u>	
Nonsubmerged Release	$\$1.52 \times 10^{6}$
Submerged Release	$\$1.00 \times 10^{6}$
<u>Costs</u>	$\$2.10 \times 10^{5}$

7. RESULTS AND CONCLUSIONS

This section contains a plant-by-plant discussion of the findings for each of the three reference plants in the study. In addition, there is a discussion on the risk-based cost effectiveness of establishing a required minimum frequency for leak testing the air-operated check valves that perform the pressure isolation function. Finally, there is an overall discussion of the generic implications, insights and conclusions derived from this study.

7.1 Results From the Peach Bottom Analysis

For Peach Bottom, the following potential corrective actions were identified:

1. Leak testing of each air-operated PIV check valve after individual maintenance.
2. Performance of ECCS logic system functional testing during shutdown (not during power operation).
3. Leak testing of air-operated PIV check valves in the HPCI and RCIC injection lines at every refueling.

Based upon the cost-benefit analysis in Section 6.2.1 (summarized in Table 6.1) all three actions were found to be cost-effective improvements when taken either individually or together. This is demonstrated by the fact that in each case the risk-based estimated costs fell below the range of estimated benefits. The range of estimated benefits reflects the uncertainty assigned to the radiological source terms.

7.2 Results From the Nine Mile Point 2 Analysis

For Nine Mile Point 2, the following potential corrective actions were identified:

1. Do not cycle valves F052A(B) and F218A(B) during power operation.
2. Do not cycle valves F087(A)B during power operation.

Here again, based upon the cost-benefit analysis of Section 6.2.2 and as summarized in Table 6.2, these two corrective actions were found to be cost-effective improvements when taken either individually or together.

7.3 Results From the Quad Cities Analysis

For Quad Cities, the following potential corrective actions were identified:

1. Leak testing of all air-operated PIV check valves at every refueling.
2. Leak testing each air-operated PIV check valve after individual maintenance.

In this particular case, the cost-benefit analysis of Section 6.2.3 (summarized in Table 6.3) did not show either corrective action to be cost-beneficial. The deciding differences for both of these proposed corrective actions were the need identified by Commonwealth Edison to physically install pressure taps around each of the subject pressure isolation valves and the fact that

Quad Cities already had other features that reduced its vulnerability to ISLs. (For example, Quad Cities does not perform logic system functional tests at power.) The hardware costs associated with this modification drove the risk-based calculated costs higher than the calculated benefits.

7.4 Results of the Minimum Testing Requirements Analysis

One of the primary goals of this study was to determine the cost-benefit relationship associated with requiring plants that do not currently have any leak testing requirements on their pressure isolation valves to institute such a program. However, all of the reference plants already have various requirements related to leak testing. Therefore, it was decided that since none of the reference plants represented a true "base case" model in this area an additional base case model would have to be created. The base case model was taken to be the Peach Bottom model with all PIV leak testing aspects removed. Removing the leak testing benefits from the Peach Bottom model resulted in a large increase in predicted core damage frequency due to ISL. Based upon the results of a separate sensitivity study, it appears sufficient for the minimum leak testing program to include provisions such that leak testing be performed at each refueling as well as after individual valve maintenance. The risk-based benefits calculated for this leak testing program show that such testing schemes are cost effective (see Section 6.2.4 and Table 6.4).

7.5 Final Conclusions

The previous four subsections have addressed insights derived from the risk-based cost benefit analyses from Section 6. This final subsection provides an overview of the entire study from a more fundamental viewpoint; namely, core damage frequency. Table 7.1 provides a convenient collection of the pertinent CDFs presented throughout this report. The table will be used to facilitate comparisons and derive insights.

The insights from this study fall into two basic categories. The first category deals with assuring that that the pressure boundaries are intact prior to increasing reactor pressure and the second category deals with how to avoid placing the plant unnecessarily into a more vulnerable mode of plant operation.

The first category above is addressed by PIV leak testing provisions. From Table 7.1, "Peach Bottom (no leak testing)" represents the analysis done in Appendix H wherein the Peach Bottom model was stripped of all credit for its current leak testing practices. "Peach Bottom (current)" refers to the Peach Bottom plant as found and modelled. "Peach Bottom (with leak testing)" is again from Appendix H and reflects the minimum leak testing provisions addressed in Section 7.4. Comparing the "no-testing case" to "Peach Bottom (current)" shows that the existing level of leak testing has already reduced the Peach Bottom CDF due to ISLs by an order of magnitude. Comparing "Peach Bottom (current)" to "Peach Bottom (with leak testing)" shows another order of magnitude reduction is still available. A significant benefit (similar to that derived for Peach Bottom) for such a leak testing program is expected to hold across the BWR population.

The second category of insights is addressed by changing current testing practices. These testing practices can be almost as significant as implementation of a leak testing program, however, they are quite plant-specific. The dominant example from this study is found at Nine Mile Point 2 (NMP). By comparing the two NMP-2 entries in Table 7.1, there is apparently more than a two order of magnitude decrease in the CDF for ISL available by prohibiting the currently allowed practice of stroke testing the valves in the steam condensing lines to the RHR heat exchangers (with the reactor pressurized) and allow-allowing the stroke testing to await a convenient shutdown (with the reactor depressurized).

A second example of significant testing-induced risk can be seen by comparing "Peach Bottom (current)" with "Peach Bottom (logic test at shutdown)" from Table 7.1. This is the single most effective corrective action identified for the Peach Bottom plant in reducing core damage frequency. Current Peach Bottom testing requirements include the provision to test the ECCS logic every six months whether or not the reactor is pressurized. By holding off on the ECCS logic system functional test until a reactor shutdown comes along (i.e. the reactor is depressurized), the ISL CDF can be reduced by almost an order of magnitude.

In summary, the results of this study show that institution of a minimum leak testing program for the air-operated pressure isolation check valves represents a significant reduction in the estimated ISL CDF for the three plants studied, which should apply across the entire BWR population. In addition, it has been shown that some of the current BWR testing practices can also represent a large contribution to ISL CDF and that this testing induced risk is easily removed by rather simple and cost-effective changes to existing testing procedures.

Table 7.1
Summary of Estimated ISL CDF vs. Plant States

Plant State	CDF/Year	Source
Peach Bottom (No leak testing)	1.86E-5	Table H.1
Peach Bottom (Current)	1.02E-6	Table 5.1
Peach Bottom (With leak testing)	1.97E-7	Table H.1
Nine Mile Point 2 (Current)	8.81E-6	Table 5.6
Nine Mile Point 2 (With all fixes)	3.22E-8	Table 5.9
Peach Bottom (Logic test at shutdown)	1.21E-7	Table 5.3

APPENDIX A: Information Collected for Interfacing Lines

A.1 Interfacing Lines at Peach Bottom

The interfacing lines identified for Peach Bottom were 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.1.1-A.1.6. Tables A.1.1-A.1.6 list some data collected for them. Table A.1.7 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 was included in the study. A letter means that the line was 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 such that 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 450 psi. There are two one-inch relief valves and two three-inch relief valves that discharge to the clean rad-waste system. If an interfacing LOCA occurs, the following indications 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. There is also one one-inch relief valve on the suction piping to each pump. The available indications for an interfacing LOCA are the same as those for the LPCI lines, except that the high suction pressure alarm replaces the 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. These valves 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

The 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

The core spray pumps start on a 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 an automatic open signal, the two injection valves are interlocked and 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 piping section has a design pressure of 450 psi. A two-inch relief valve with setpoint of 435 psig is located in this pipe section and 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. This 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 and 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 or the torus level is high. After they are fully open, the suction valve, 17, from the CST will be automatically closed. Suction valves from the suppression pool and the two steam isolation valves are closed by excess steam supply line space high temperature or high steam supply line pressure differential or high steam line pressure differential signals.

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. This 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 and 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 actuates 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. This also actuates an alarm in the control room on high high sump level.

5. Condensate storage tank low level and high 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. The suction path from the condensate storage tank is normally open. The pump suction valve receives an open signal on system auto initiation. The outboard injection valve, 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 the CST to the 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 the 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. This piping has a design pressure of 150 psi. There is a one-inch relief valve of setpoint 100 psig in this pipe section and it discharges to clean rad waste. If an interfacing LOCA occurs in this pipe section, in addition to the low vessel level alarm and the actuation of emergency core cooling systems (ECCS), 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.

3. Room ventilation temperature is indicated.

4. The reactor building drain sump pumps will start automatically. This is indicated and alarmed in the control room of the rad-waste building and it also actuates an alarm in the main control room.

5. High RCIC pump suction pressure alarm in the control room.

6. Low CST level alarm in the control room.

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

8. High RCIC pump room radiation and high reactor building sump area radiation alarm in the control room.

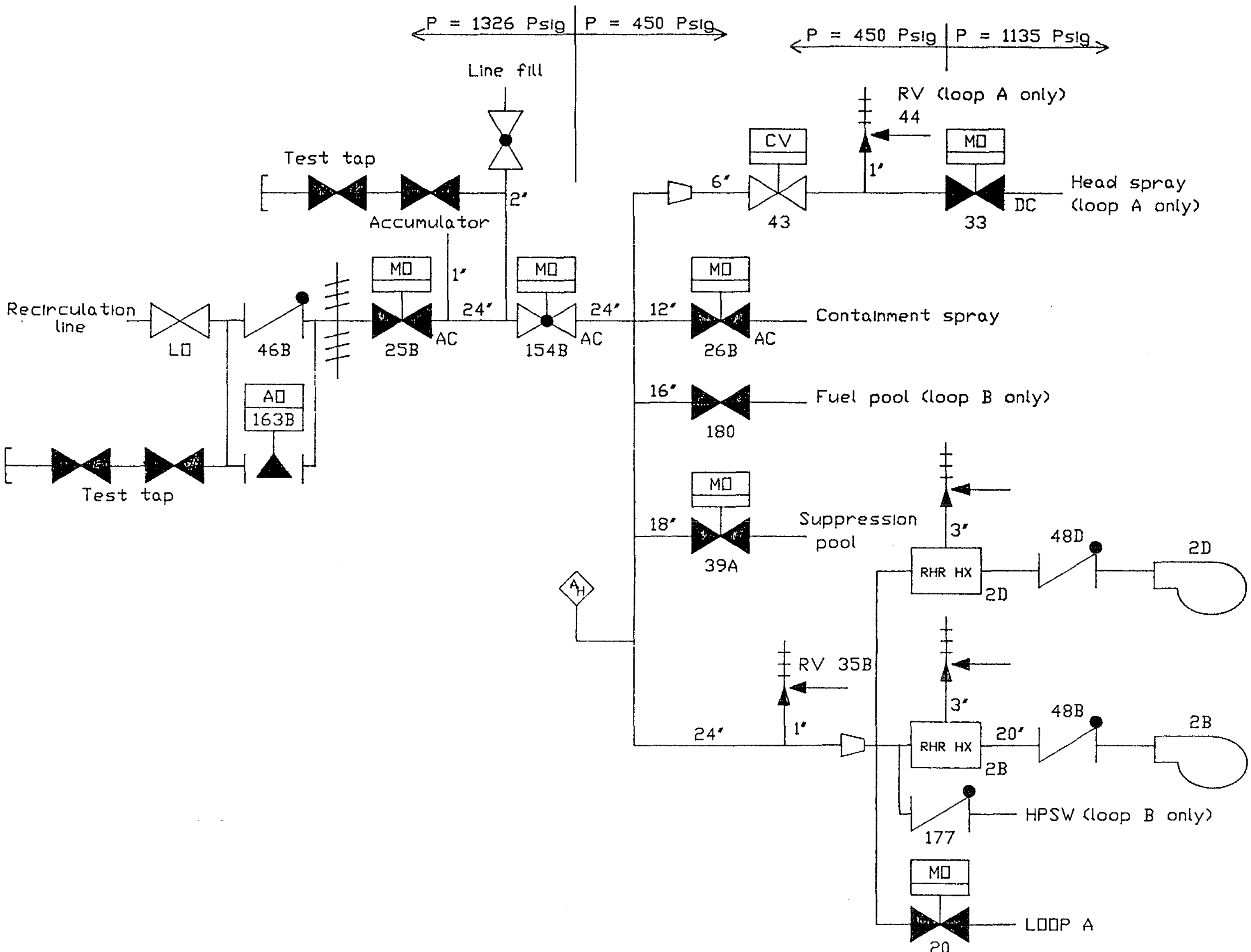


Figure A.1.1 LPCI (RHR) injection lines.
(Peach Bottom)

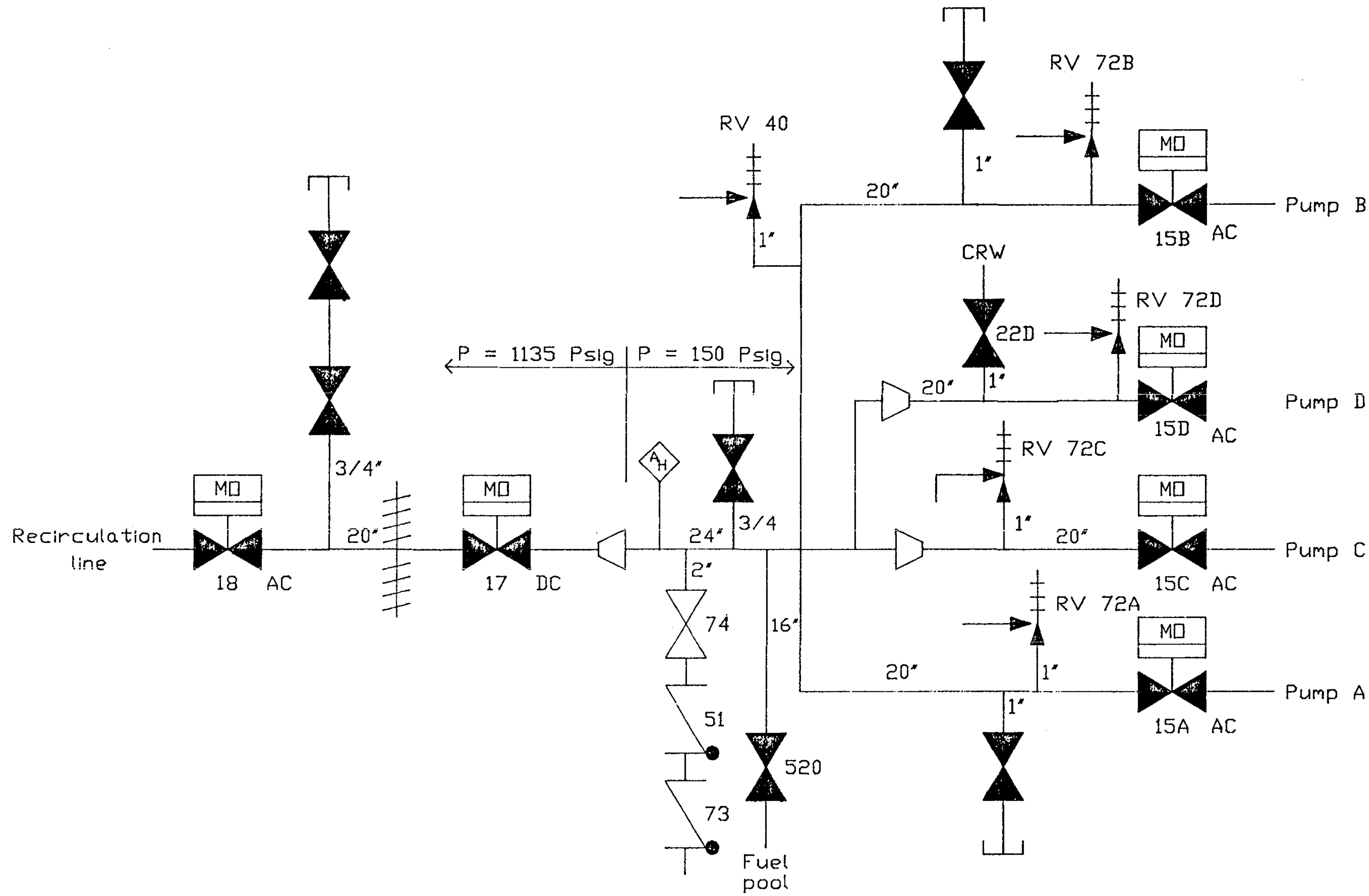


Figure A.1.2 Shutdown cooling suction (RHR).
(Peach Bottom)

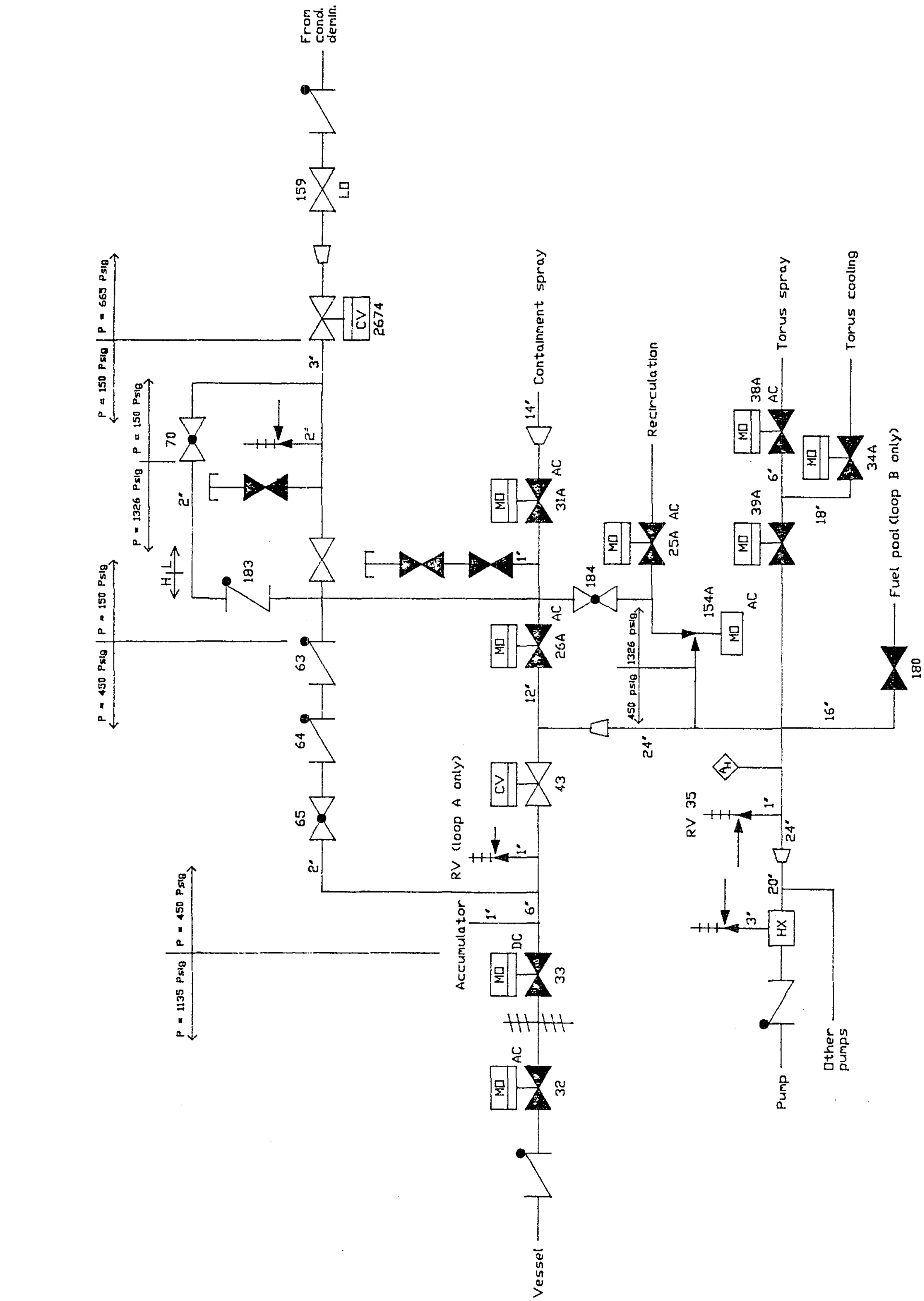


Figure A.1.3 Vessel head spray (RHR).
(Peach Bottom)

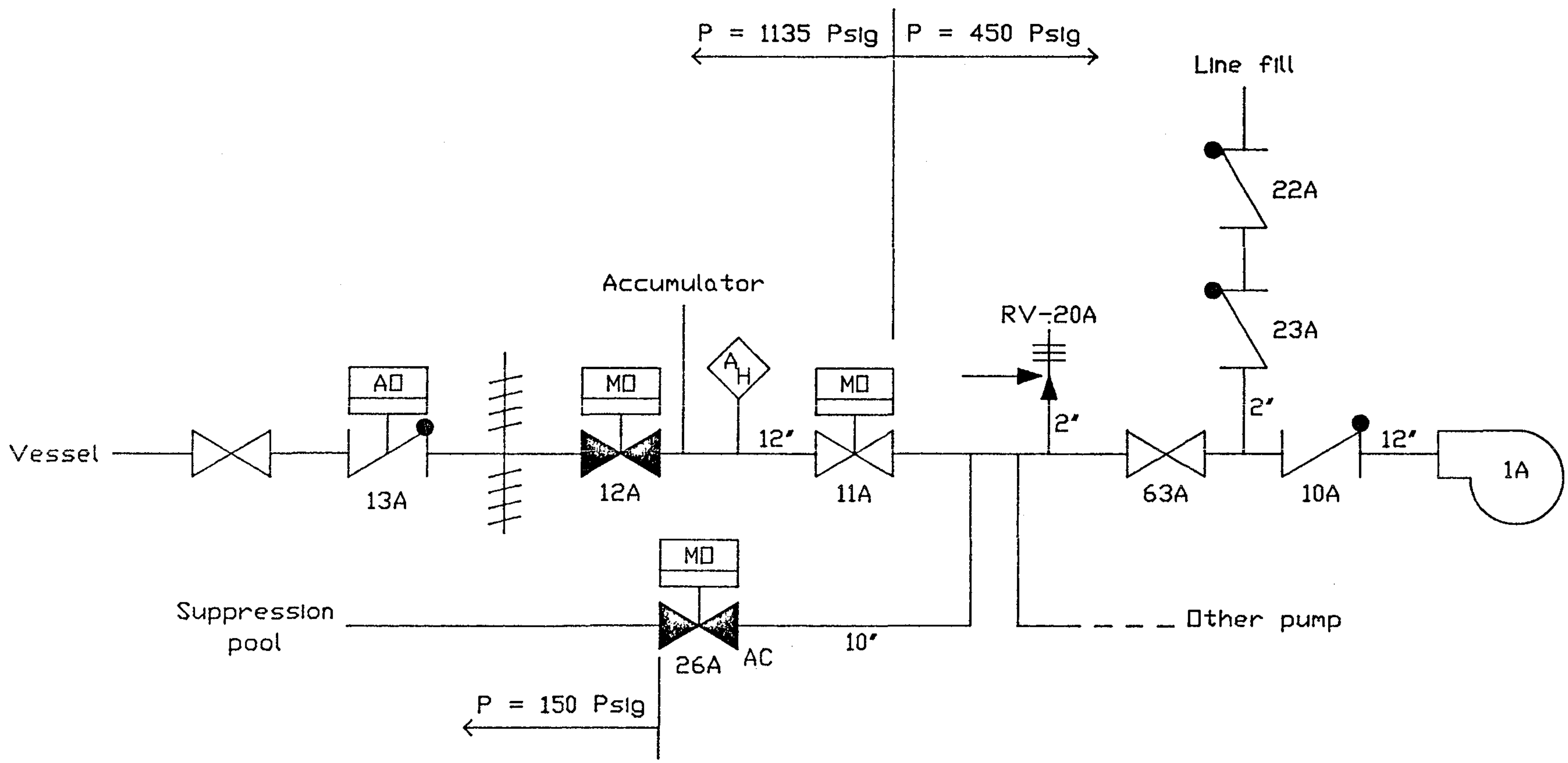


Figure A.1.4 Core spray injection lines.
(Peach Bottom)

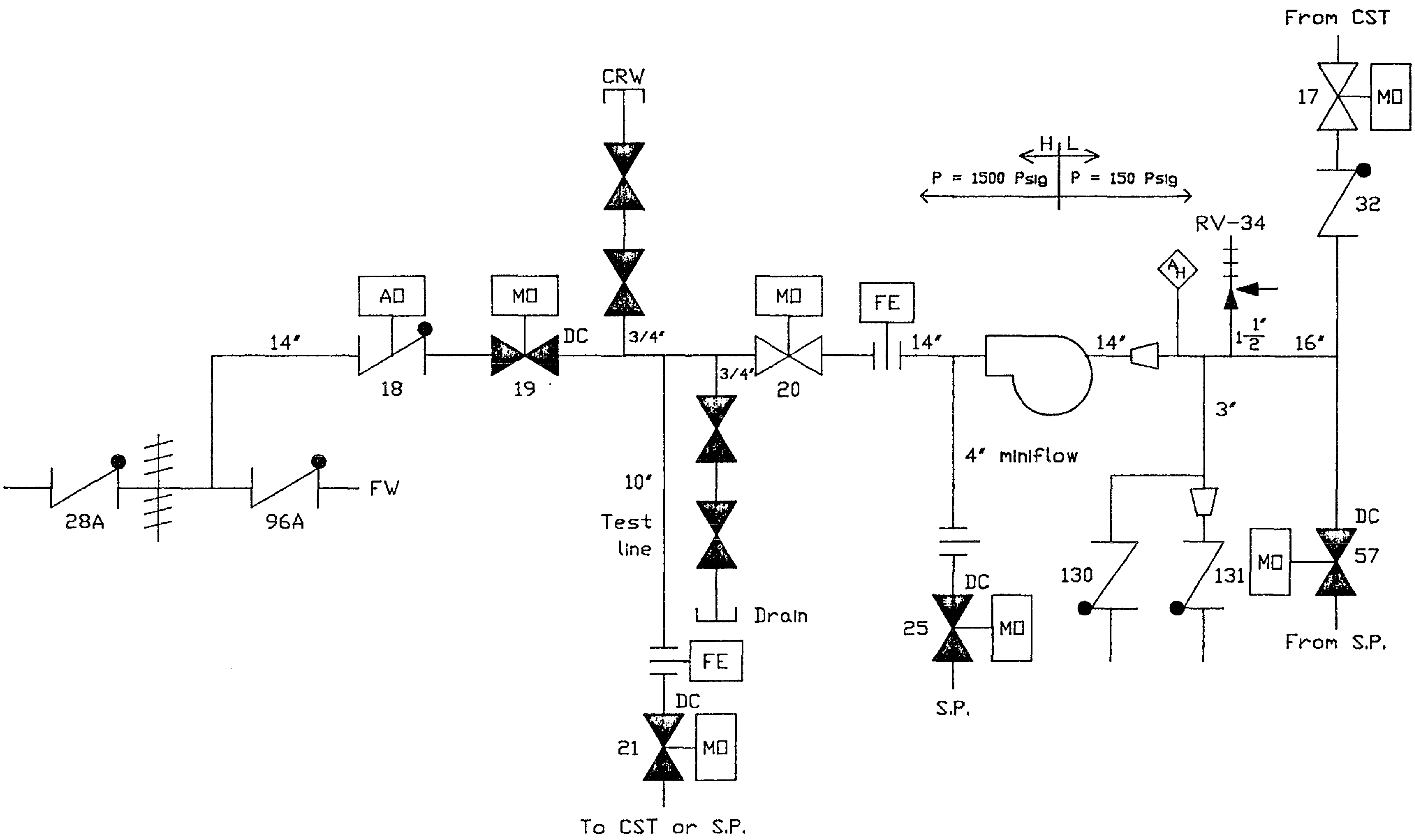


Figure A.1.5 HPCI suction.
(Peach Bottom)

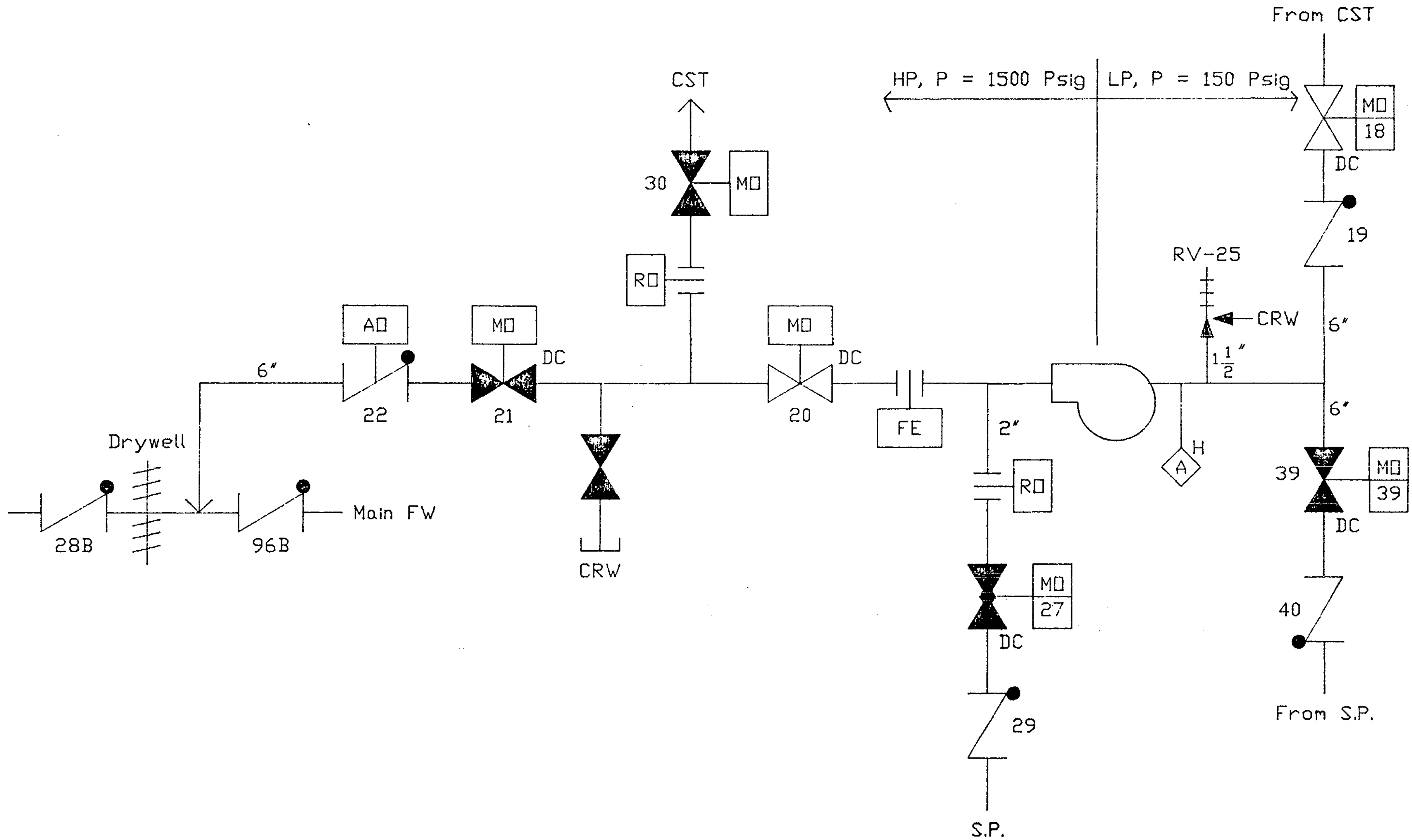


Figure A.1.6 RCIC suction.
(Peach Bottom)

Table A.1.1
LPCI (RHR) Injection Lines (Peach Bottom)

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 at 450 psig.		

*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, recent Technical Specification amendment request requires LLRT each fuel cycle and post maintenance.

Table A.1.2
Shutdown Cooling Suction (RHR) (Peach Bottom)

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.1.3
Vessel Head Spray (RHR) (Peach Bottom)

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.1.4
Core Spray Injection Lines (Peach Bottom)

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, recent Technical Specification amendment request requires LLRT each fuel cycle and post maintenance.

Table A.1.5
HPCI Suction (Peach Bottom)

1.	Number of lines -	1		
2.	Line size -	14"		
3.	Valve number -	18	19	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	none
10.	Normal flow direction -	in	in	in
11.	Surveillance requirement -	+	**	***
12.	Pump surveillance requirement -	started monthly, flow test/3 months, auto actuation every cycle		
13.	Relief valves -	RV-34 10 gpm at 100 psig		

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

Table A.1.6
RCIC Suction (Peach Bottom)

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	O
8.	Power failure position -	---	C	O
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 at 100 psig		

*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 A.1.7
Screening of Lines Penetrating Containment for Interfacing Lines at Peach Bottom

PBAPS

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	
*	Feedwater	N-9	2	24	1	Check	Open	1	Check	Open	
D	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			
*	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	18	-	--	-	2	MO Globe	Closed	Second valve is MO gate.
E	RHR Containment Spray-Drywell	N-39	2	14	-	--	-	2	MO Gate	Closed	
*	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.
*	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	
*	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	HPCE 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.
B	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	2	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.

Table A.1.7 (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 were 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 Lines to RHR Heat Exchangers

These interfacing lines are shown in Figures A.2.1-A.2.8. Tables A.2.1-A.2.8 list some data collected for them. Table A.2.9 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 was included in the study. A letter means that the line was 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. Loops 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 for 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 the 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 differential 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 the test return line to the suppression pool.
f. Containment spray to the 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 a manual override control that permits 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 would 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, and the 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 would be overpressurized is bounded by valves F042, F063, F025, F021, F085, and F031. The design pressure of this piping 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 a pressure interlock so that a valve can not be opened if the inboard pressure is high. They are open 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 piping 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. (This 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 valve 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 an 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 the 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 would receive an automatic isolation signal.

A.2.4 Low Pressure Core Spray Injection Line

A.2.4.1 Automatic and Manual Control

The 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, and 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. A 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 would be pressurized is bounded by valves F004, F003, F010, F023, F024, F006, F035, and F026. This section is rated for high pressure. Therefore, no overpressurization would be expected to occur, additional valve failures must also occur to result in overpressurization. If the HPCS discharge valve also fails open, then the low pressure piping on the suction side will be overpressurized. The overpressurization would be 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 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 valve from the condensate storage tank F010 is normally open and will close automatically when the suction valve F031 from the suppression pool is opened.

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 Indications of Overpressurization or Interfacing LOCA

If valves F066, F065, and F013 fail open, the reactor pressure would overpressurize the suction side of the RCIC pump. The overpressurization would be bounded by valves F013, F006, F022, F011, F061, F026A, F026B, F030, F057, and F019. The design pressure of the pump suction piping is 100 psig. Three relief valves F036, F017, and F018 are located in this section. If an interfacing LOCA occurs, the following indications would 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. This 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 valves are 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 an automatic isolation signal on low vessel level, high vessel pressure or high RHR equipment room ambient temperature.

A.2.7.2 Indications of Overpressurization or Interfacing LOCA

If isolation valves F050 and F053 fail open, the low pressure piping that would be overpressurized is identical to that for a LPCI line (see Figure A.2.1). 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 as soon as 1-1/2 hours after a reactor trip. It is capable of condensing all the steam generated at that time. 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.2.8.

A.2.8.2 Indications of Overpressurization or Interfacing LOCA

If pressure isolation valves F052 and F051 or F087 fail open, the low pressure piping that will be overpressurized is the same as that for the 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.

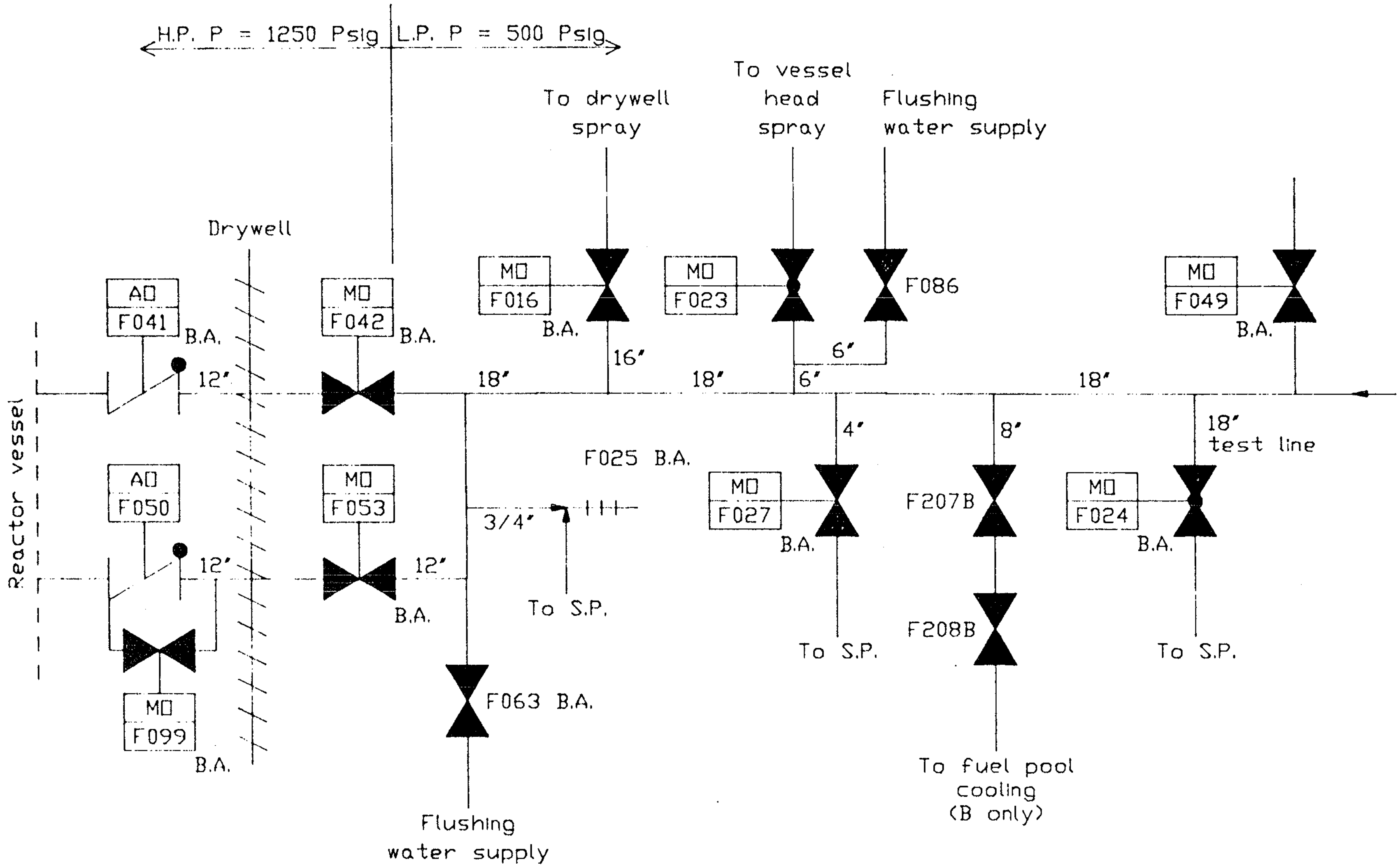


Figure A.2.1 **LPCI injection lines for pumps A, B, and shutdown cooling return to recirculation line (sheet 1 of 2).** (Nine Mile Point 2)

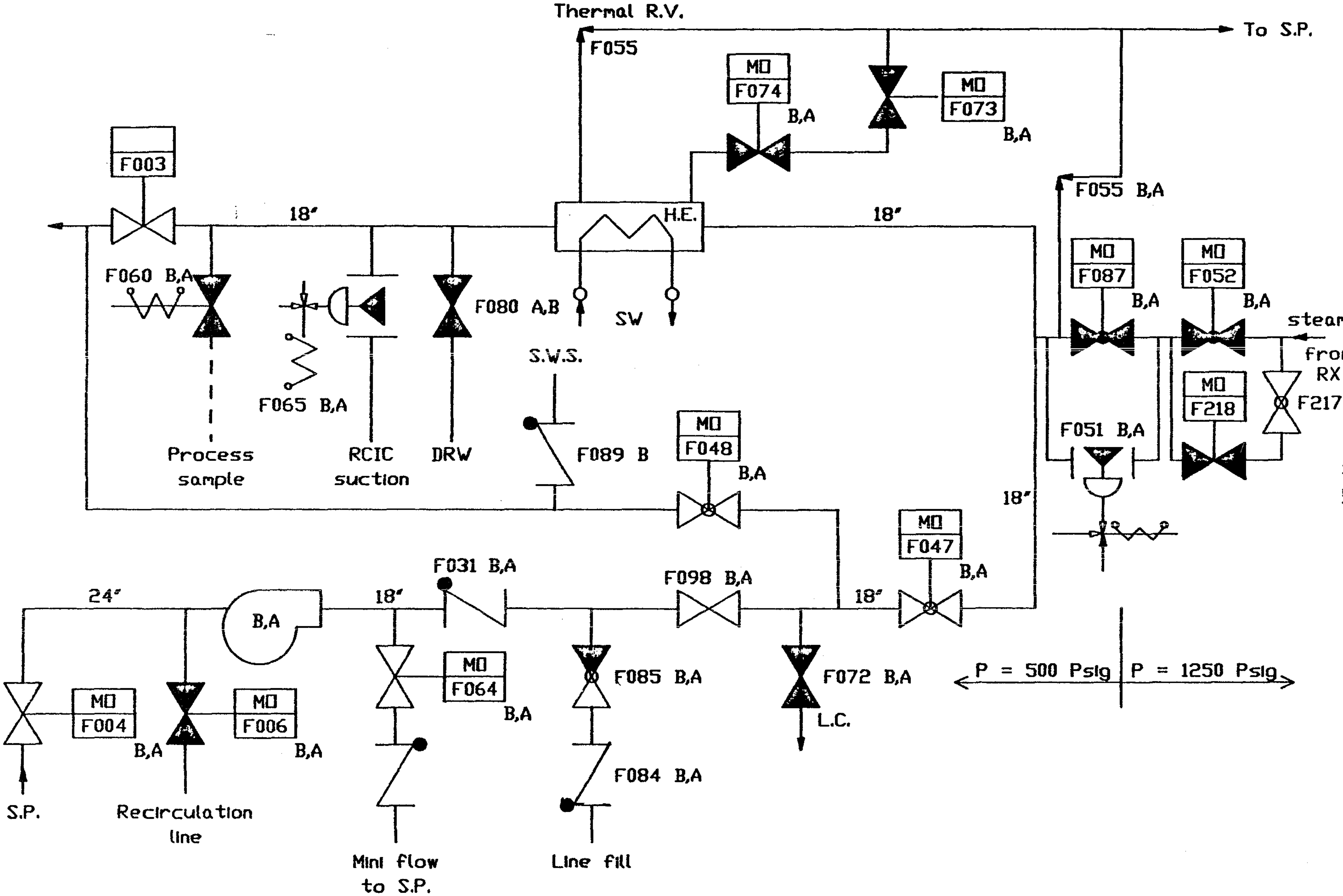


Figure A.2.1 LPCI injection lines for pumps A, B, and shutdown cooling return to recirculation line (sheet 2 of 2). (Nine Mile Point 2)

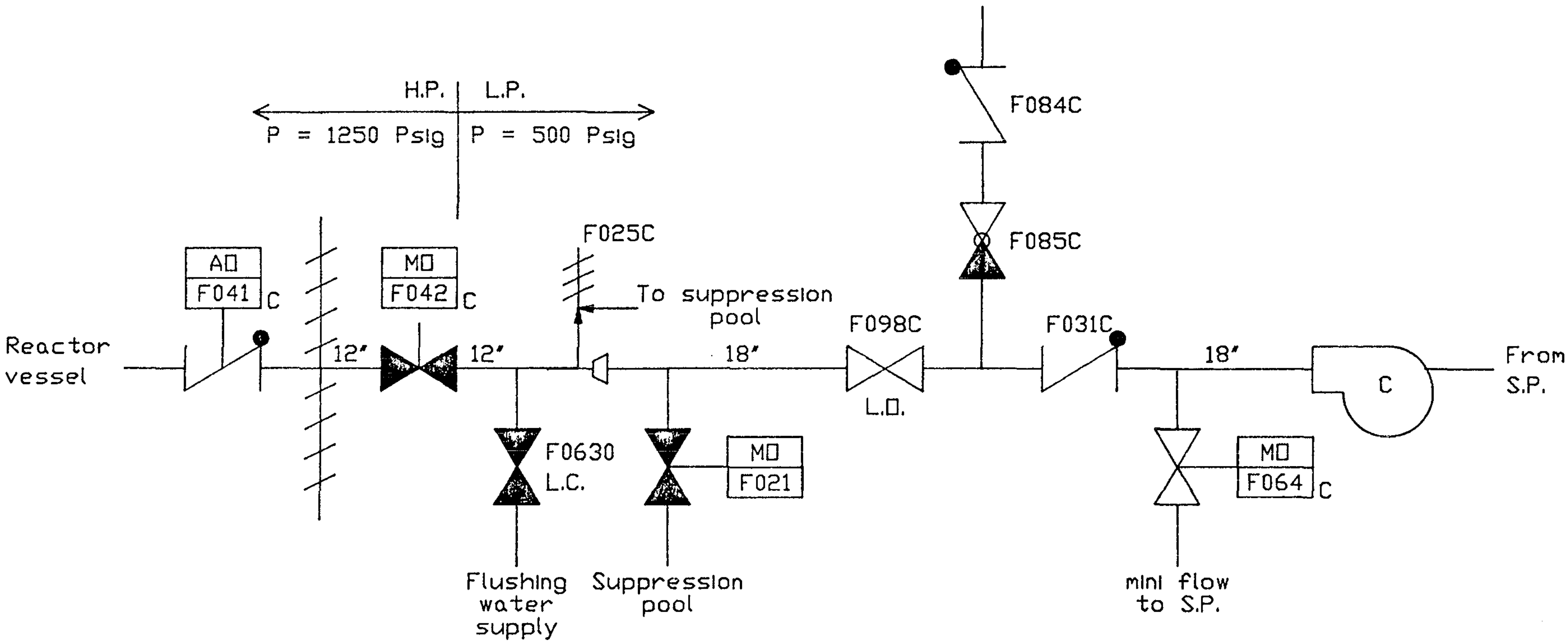


Figure A.2.2 LPCI injection line for pump C.
(Nine Mile Point 2)

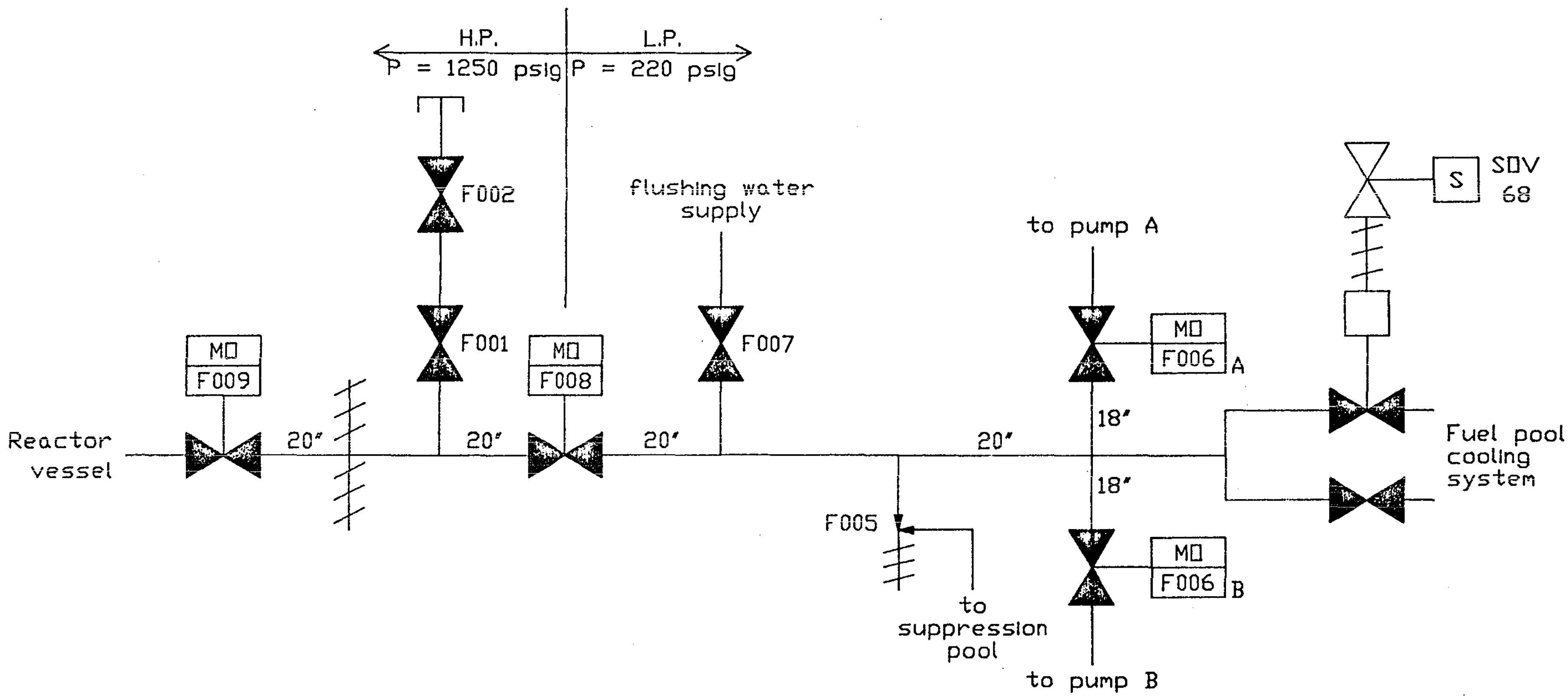


Figure A.2.3 Shutdown cooling suction.
(Nine Mile Point 2)

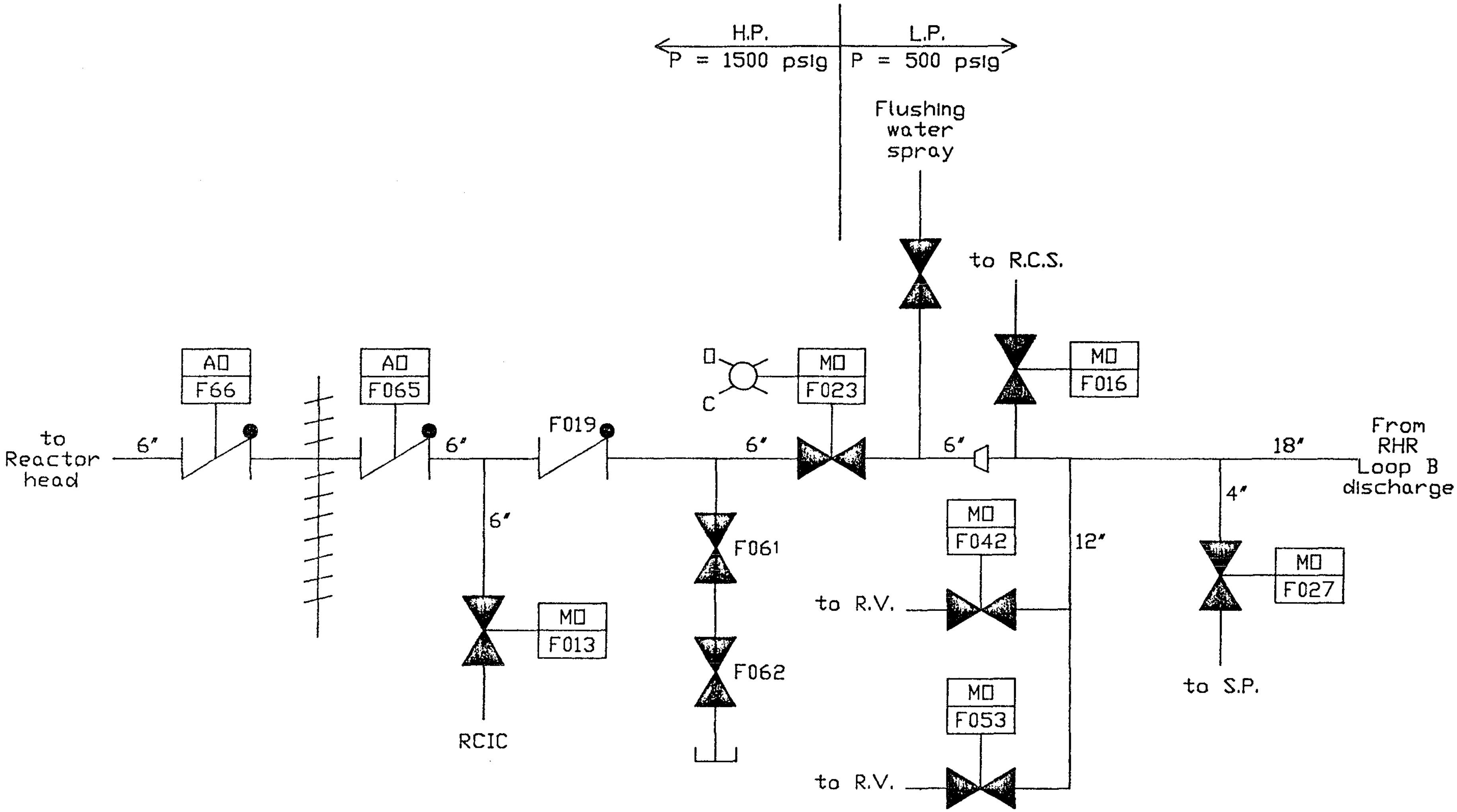


Figure A.2.4 Reactor vessel head spray line.
(Nine Mile Point 2)

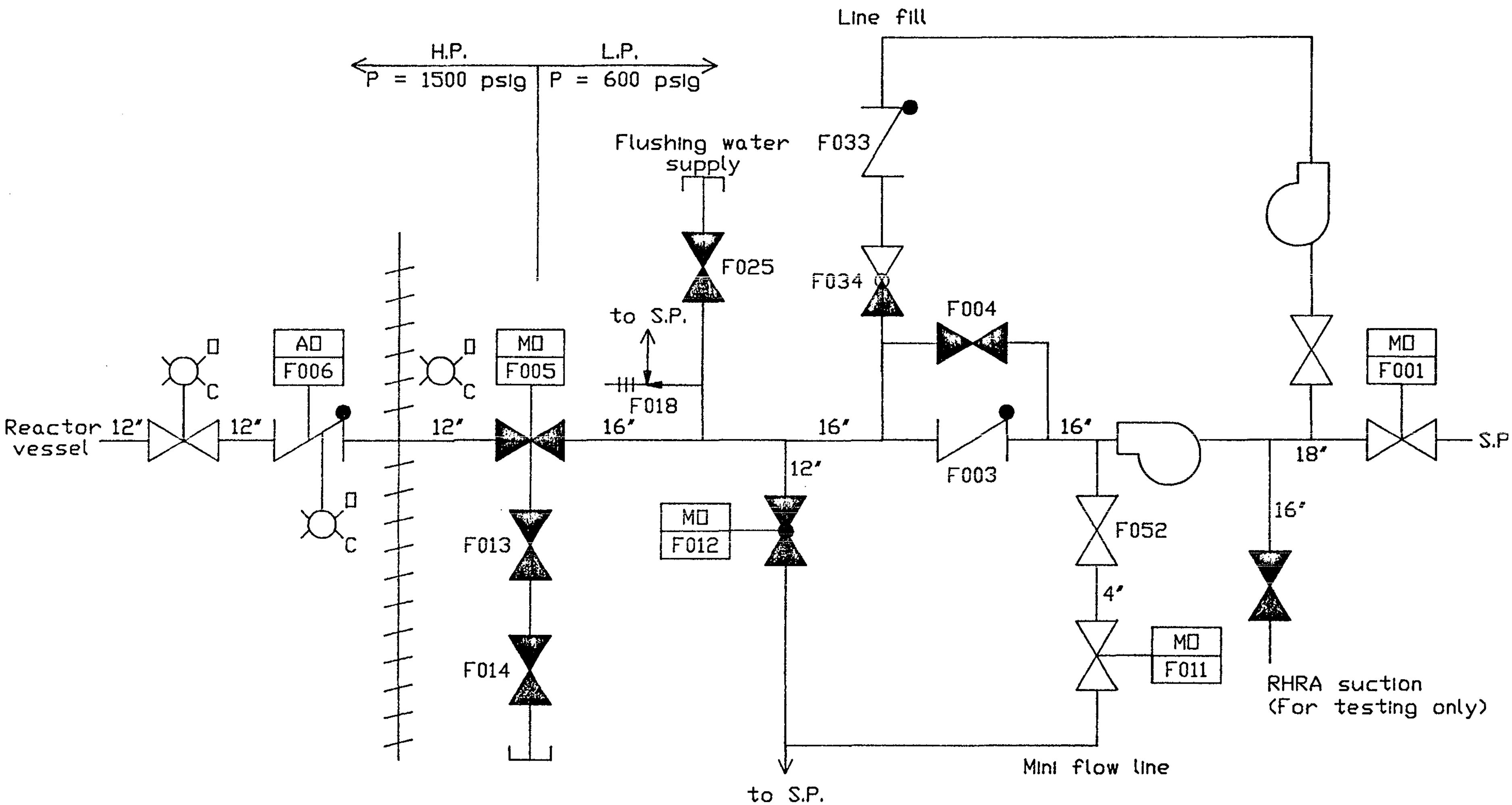


Figure A.2.5 Low pressure core spray injection line.
(Nine Mile Point 2)

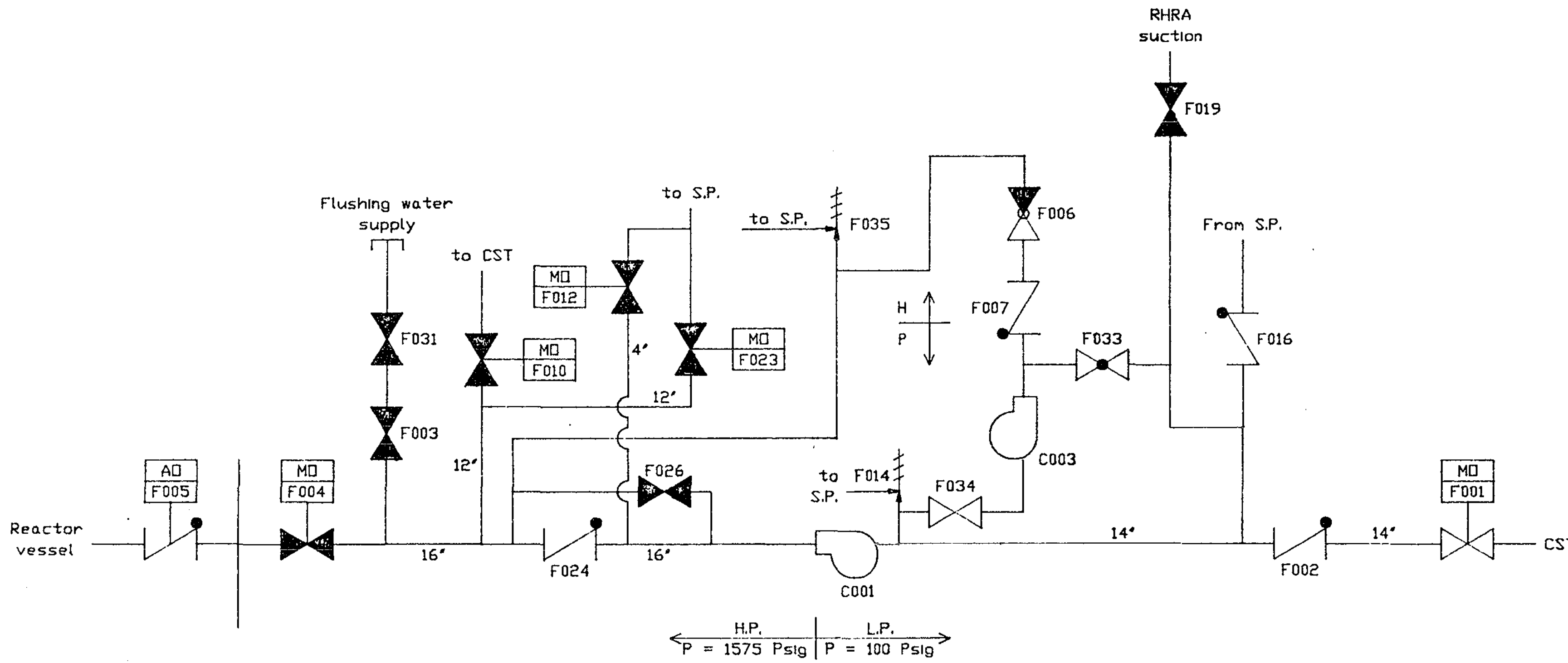


Figure A.2.6 High pressure core spray system.
(Nine Mile Point 2)

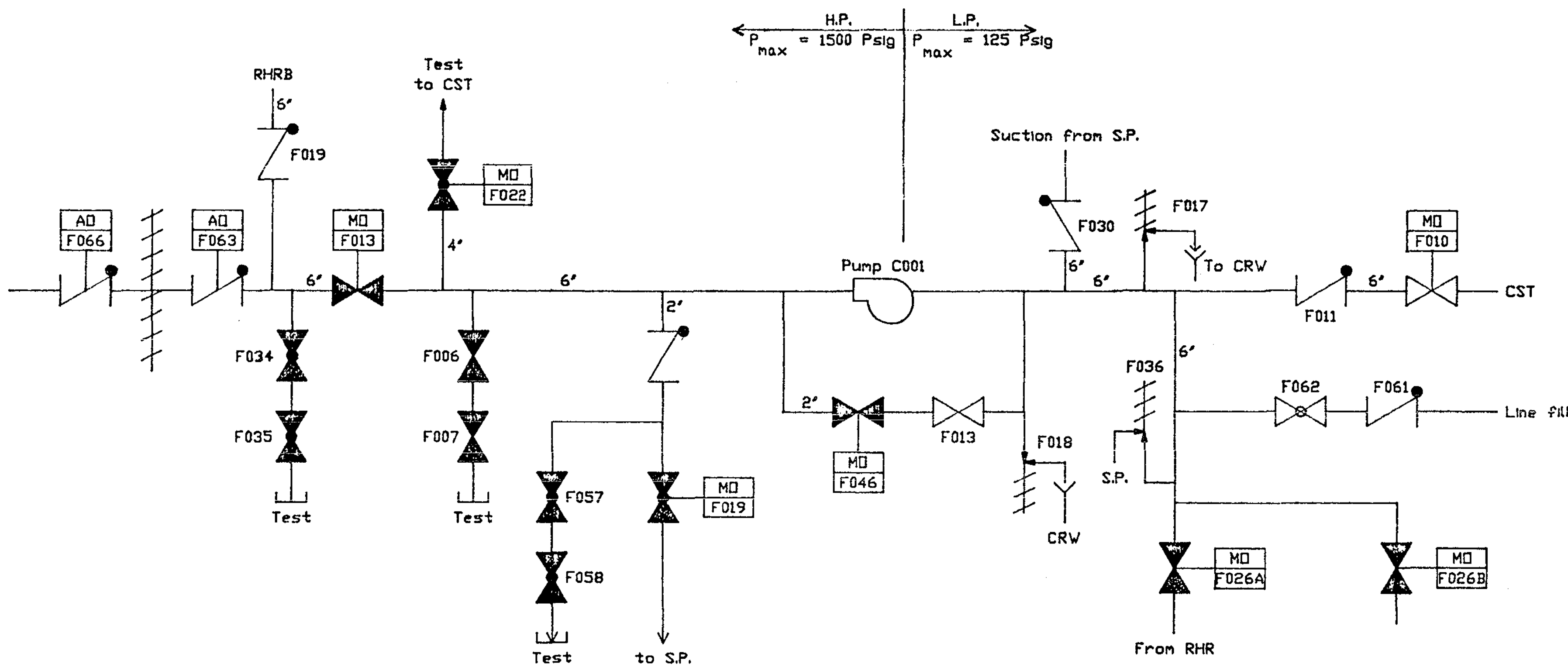


Figure A.2.7 RCIC pump suction.
(Nine Mile Point 2)

Table A.2.1
LPCI Injection Lines (Nine Mile Point 2)

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 $\leq$ 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.2.2
Shutdown Cooling Suction (Nine Mile Point 2)

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.2.3
Vessel Head Spray (RCIC) (Nine Mile Point 2)

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.2.4
Low Pressure Core Spray Injection Line (Nine Mile Point 2)

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.2.5
HPCS Pump Suction (Nine Mile Point 2)

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.2.6
RCIC Pump Suction (Nine Mile Point 2)

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.2.7
Shutdown Cooling Return to Recirculation (Nine Mile Point 2)

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.2.8
RHR Steam Condensing Supply Line (Nine Mile Point 2)

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.2.9
Screening of Lines Penetrating Containment for Interfacing Lines at Nine Mile Point-2

												Va							
	Pene-tration No.	System Designation	GDC or Reg. Guide	ESF System	Fluid	Size (in)	FSAR Arrange-ment Figure(1)	Location of valve Inside/ Outside Primary Contain-ment	Length of Pipe - Con-tainment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Number SWEC	Number GE	Type	Oper-ator	Actuator Mode Primary	Actuator Mode Secondary	Normal (3)	Sh
A	Z-1A	Main steam Line A	55	No	Steam	26	6.2-70 Sh. 1	Inside		C	Yes	2MSS*HYV6A	B22-F022A	Ball	HYV	Hydraulic to open; spring to close	N/A	Open	Cl
								Outside	5'-2"	C		2MSS*HYV7A	B22-F028A	Ball	HYV				
B		Main steam Line A drain line				2		Outside	36'-0"	C		2MSS*MOV208	-	Globe	MOV	Elec.	Manual	Closed	Cl
						3/4		Outside	13'-10"			2MSS*SOV97A	B22-F067A	Globe	SOV	Elec.	N/A	Closed	Clc
A	Z-1B	Main steam Line B	55	No	Steam	26	6.2-70 Sh. 1	Inside		C	Yes	2MSS*HYV6B	B22-F022B	Ball	HYV	Hydraulic to open; spring to close	N/A	Open	Cl
								Outside	5'-2"	C		2MSS*HYV7B	B22-F028B	Ball	HYV				
B		Main steam Line B drain line				2		Outside	36'-0"	C		2MSS*MOV208	-	Globe	MOV	Elec.	Manual	Closed	Cl
						3/4		Outside	15'-6"			2MSS*SOV97B	B22-F067B	Globe	SOV	Elec.	N/A	Closed	Clo
A	Z-1C	Main steam Line C	55	No	Steam	26	6.2-70 Sh. 1	Inside		C	Yes	2MSS*HYV6C	B22-F022C	Ball	HYV	Hydraulic to open; spring to close	N/A	Open	Cl
								Outside	5'-2"	C		2MSS*HYV7C	B22-F028C	Ball	HYV				
B		Main steam Line C drain line				2		Outside	36'-0"	C		2MSS*MOV208	-	Globe	MOV	Elec.	Manual	Closed	Cl
						3/4		Outside	15'-5"			2MSS*SOV97C	B22-F067C	Globe	SOV	Elec.	N/A	Closed	Clo
A	Z-1D	Main steam Line D	55	No	Steam	26	6.2-70 Sh. 1	Inside		C	Yes	2MSS*HYV6D	B22-F022D	Ball	HYV	Hydraulic to open; spring to close	N/A	Open	Cl
								Outside	5'-2"	C		2MSS*HYV7D	B22-F028D	Ball	HYV				
B		Main steam Line D drain line				2		Outside	36'-0"	C		2MSS*MOV208	-	Globe	MOV	Elec.	Manual	Closed	Cl
						3/4		Outside	13'-1"			2MSS*SOV97D	B22-F067D	Globe	SOV	Elec.	N/A	Closed	Clo
A	Z-2	Main steam drain line	55	No	Steam	6	6.2-70 Sh. 2	Inside		C	Yes	2MSS*MOV111	B22-F016	Globe	MOV	Elec.	Manual	Closed	Cl
								Outside	1'-0"	C		2MSS*MOV112	B22-F019	Globe	MOV	Elec.	Manual	Closed	Cl
	Z-3	Spare								A									

...h of Con... at to ...ide ...tion ...ve	Type Test (1)	Potential Bypass Leakage Path	Number SWEC	Number GE	Type	Oper-ator	Actuator Mode Primary	Actuator Mode Secondary	Position Normal (3)	Position Shutdown	Position Post-Accident	Position Power Failure(10)	Isolation Signal (4)	Closure Time (5,6)	Power Source (7)	Notes	
	C C	Yes	2MSS*HYV6A 2MSS*HYV7A	B22-F022A B22-F028A	Ball Ball	HYV HYV	Hydraulic to open; spring to close	N/A	Open	Closed	Closed	Closed	X,C,D, E,P,T, R,RM	3 to 5 sec	N/A	8	
	C		2MSS*MOV208	-	Globe	MOV	Elec.	Manual	Closed	Closed	Closed	FAI	X,C,D,E, P,T,R,RM	9 sec	Div I		17
			2MSS*SOV97A	B22-F067A	Globe	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	RM(2)	N/A	N/A		
	C C	Yes	2MSS*HYV6B 2MSS*HYV7B	B22-F022B B22-F028B	Ball Ball	HYV HYV	Hydraulic to open; spring to close	N/A	Open	Closed	Closed	Closed	X,C,D, E,P,R, T,RM	3 to 5 sec	N/A N/A	8	
	C		2MSS*MOV208	-	Globe	MOV	Elec.	Manual	Closed	Closed	Closed	FAI	X,C,D,E, P,R,T,RM	9 sec	Div I		17
			2MSS*SOV97B	B22-F067B	Globe	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	RM(2)	N/A	N/A		
	C C	Yes	2MSS*HYV6C 2MSS*HYV7C	B22-F022C B22-F028C	Ball Ball	HYV HYV	Hydraulic to open; spring to close	N/A	Open	Closed	Closed	Closed	X,C,D, E,P,T, R,RM	3 to 5 sec	N/A	8	
	C		2MSS*MOV208	-	Globe	MOV	Elec.	Manual	Closed	Closed	Closed	FAI	X,C,D,E P,R,T,RM	9 sec	Div I		17
			2MSS*SOV97C	B22-F067C	Globe	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	RM(2)	N/A	N/A		
	C C	Yes	2MSS*HYV6D 2MSS*HYV7D	B22-F022D B22-F028D	Ball Ball	HYV HYV	Hydraulic to open; spring to close	N/A	Open	Closed	Closed	Closed	X,C,D, E,P,T, R,RM	3 to 5 sec	N/A	8	
	C		2MSS*MOV208	-	Globe	MOV	Elec.	Manual	Closed	Closed	Closed	FAI	X,C,D,E, P,T,R,RM	9 sec	Div I		17
			2MSS*SOV97D	B22-F067D	Globe	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	RM(2)	N/A	N/A		
	C	Yes	2MSS*MOV111	B22-F016	Globe	MOV	Elec.	Manual	Closed	Closed	Closed	FAI	X,C,D,E, P,T,R,RM	38 sec	Div II		
	C		2MSS*MOV112	B22-F019	Globe	MOV	Elec.	Manual	Closed	Closed	Closed	FAI	X,C,D,E, P,T,R,RM	38 sec	Div I		
	A																

Table A.2.9 (Continued)

	Pene-tration No.	System Designation	GDC or Reg. Guide	ESF System	Fluid	Size (in)	FSAR Arrange-ment Figure(1)	Location of valve Inside/Outside Primary Contain-ment	Length of Pipe - Con-tainment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Number SWEC	G
*	Z-4A	Feedwater line A to RPV	55	No	Water	24	6.2-70 Sh. 3	Outside	2'-1"	C	Yes	2FWS*AOV23A	E
								Inside		C		2FWS*V12A	E
								Outside	16'-4"	C		2FWS*MOV21A	E
					Water	8	6.2-70 Sh. 3	Outside	57'-8"	C		2WCS*MOV200	(
*	Z-4B	Feedwater line B to RPV	55	No	Water	24	6.2-70 Sh. 3	Inside		C	Yes(30)	2FWS*V12B	
								Outside	2'-1"	C		2FWS*AOV23B	
								Outside	16'-4"	C		2FWS*MOV21B	
					Water	8	6.2-70 Sh. 3	Outside	65'-8"	C		2WCS*MOV200	
E	Z-5A	RHS Pump A suction from suppression pool	56	Yes	Water	24	6.2-70 Sh. 4	Outside	5'-6"	C	No(29)	2RHS*MOV1A	
E	Z-5B	RHS Pump B suction from suppression pool	56	Yes	Water	24	6.2-70 Sh. 4	Outside	20'-9"	C	No(29)	2RHS*MOV1B	
E	Z-5C	RHS Pump C suction from suppression pool	56	Yes	Water	24	6.2-70 Sh. 4	Outside	9'-9"	C	No(29)	2RHS*MOV1C	
E	Z-6A	RHS test line Loop B to sup-pression pool	56	Yes	Water	18	6.2-70 Sh. 6	Outside	19'-3"	C	No(29)	2RHS*MOV30B	

...ge- ...t ...(1)	Location of valve Inside/ Outside Primary Contain- ment	Length of Pipe - Con- tainment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Number SWEC	Number GE	Valve(9) Type	Oper- ator	Actuator Mode Primary	Actuator Mode Secondary	Position Normal (3)	Position Shutdown	Position Post- Accident	Power Failure(10)	Isola- tion Signal (4)	Closure Time (5,6)	Power Source (7)	Notes	
)	Outside	2'-1"	C	Yes	2FWS*AOV23A	B22-F032A	Swing Check	AOV	Process	Spring (test only)	Open	Closed	Closed	N/A	Reverse flow	The time it takes for one valve volume to pass through the valve	N/A	11,32	21
	Inside		C		2FWS*V12A	B22-F010A	Swing Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow				
	Outside	16'-4"	C		2FWS*MOV21A	B22-F065A	Gate	MOV	Elec.	Manual	Open	Closed	Closed	FAI	RM	N/A	Div I		
	Outside	57'-8"	C		2WCS*MOV200	G33-F040	Globe	MOV	Elec.	Manual	Open	Open	Closed	FAI	RM	N/A	Div I		
	Inside		C	Yes(30)	2FWS*V12B	B22-F010B	Swing Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow	The time it takes for one valve volume to pass through the valve	N/A	11,32	
	Outside	2'-1"	C		2FWS*AOV23B	B22-F032B	Swing Check	AOV	Process	Spring (test only)	Open	Closed	Closed	N/A	Reverse flow				
	Outside	16'-4"	C		2FWS*MOV21B	B22-F065B	Gate	MOV	Elec.	Manual	Open	Closed	Closed	FAI	RM	N/A	Div II		
	Outside	65'-8"	C		2WCS*MOV200	G33-F040	Globe	MOV	Elec.	Manual	Open	Open	Closed	FAI	RM	N/A	Div I		
	Outside	5'-6"	C	No(29)	2RHS*MOV1A	E12-F004A	Tricen- tric butter- fly	MOV	Elec.	Manual	Open	Closed	Open	FAI	RM	45	Div I	13	21
	Outside	20'-9"	C	No(29)	2RHS*MOV1B	E12-F004B	Tricen- tric butter- fly	MOV	Elec.	Manual	Open	Closed	Open	FAI	RM	45	Div II	13	21
)	Outside	9'-9"	C	No(29)	2RHS*MOV1C	E12-F004C	Tricen- tric butter- fly	MOV	Elec.	Manual	Open	Closed	Open	FAI	RM	45	Div II	13	21
	Outside	19'-3"	C	No(29)	2RHS*MOV30B	E12-F201B	Tricen- tric butter- fly	MOV	Elec.	Manual	Open	Closed	Open	FAI	RM	85	Div I	15	21

Table A.2.9 (Continued)

	Pene-tration No.	System Designation	GDC or Reg. Guide	ESF System	Fluid	Size (in)	FSAR Arrange-ment Figure(1)	Location of valve Inside/ Outside Primary Contain-ment	Length of Pipe - Contain-ment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Number SWEC	Number GE	Type	Oper-ator	Actuator Primary	Actuator Mod Sec
E	Z-6B	RHS test line Loop A to sup-pression pool	56	Yes	Water	18	6.2-70 Sh. 6	Outside	10'-6"	C	No(29)	2RHS*MOV30A	E12-F201A	Tricen-tric butter-fly	MOV	Elec.	Man
E	Z-7A	RHS containment spray Loop A to suppression pool	56	Yes	Water	4	6.2-70 Sh. 7	Outside	18'-3"	C	No(29)	2RHS*MOV33A	E12-F027B	Globe	MOV	Elec.	Man
E	Z-7B	RHS containment spray Loop B to suppression pool	56	Yes	Water	4	6.2-70 Sh. 7	Outside	4'-6"	C	No(29)	2RHS*MOV33B	E12-F027B	Globe	MOV	Elec.	Man
E	Z-8A	RHS containment spray Loop A to drywell	56	Yes	Water	16	6.2-70 Sh. 8	Outside Outside	2'-0" 11'-2"	C C	No(29)	2RHS*MOV25A 2RHS*MOV15A	E12-F017A E12-F016A	Gate Gate	MOV MOV	Elec. Elec.	Man Man
E	Z-8B	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(29)	2RHS*MOV25B 2RHS*MOV15B	E12-F017B E12-F016B	Gate Gate	MOV MOV	Elec. Elec.	Man Man
*	Z-9A	RHS/LPCI Loop A to RPV	55	Yes	Water	12	6.2-70 Sh. 9	Outside Inside	7'-0"	C C	No(29)	2RHS*MOV24A 2RHS*AOV16A	E12-F042A E12-F041A	Gate Check	MOV AOV	Elec. Process	Man Air (Te
*	Z-9B	RHS/LPCI Loop B to RPV	55	Yes	Water	12	6.2-70 Sh. 9	Outside Inside	6'-6"	C C	No(29)	2RHS*MOV24B 2RHS*AOV16B	E12-F042B E12-F041B	Gate Check	MOV AOV	Elec. Process	Man Air (Te
*	Z-9C	RHS/LPCI Loop C to RPV	55	Yes	Water	12	6.2-70 Sh. 9	Outside Inside	6'-6"	C C	No(29)	2RHS*MOV24C 2RHS*AOV16C	E12-F042C E12-F041C	Gate Check	MOV AOV	Elec. Process	Man Air (Te

FSAR rrange- ment gure(1)	Location of valve Inside/ Outside Primary Contain-ment	Length of Pipe - Contain-ment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Number SWEC	Number GE	Valve(9) Type	Oper-ator	Actuator Mode Primary	Actuator Mode Secondary	Position Normal (3)	Position Shutdown	Position Post-Accident	Power Failure(10)	Isola-tion Signal (4)	Closure Time (5,6)	Power Source (7)	Notes	
2-70 . 6	Outside	10'-6"	C	No(29)	2RHS*MOV30A	E12-F201A	Tricen- tric butter- fly	MOV	Elec.	Manual	Open	Closed	Open	FAI	RM	85	Div II	15	21
2-70 . 7	Outside	18'-3"	C	No(29)	2RHS*MOV33A	E12-F027B	Globe	MOV	Elec.	Manual	Closed	Closed	Open	FAI	B,F,RM	15	Div I	14,15	21
2-70 . 7	Outside	4'-6"	C	No(29)	2RHS*MOV33B	E12-F027B	Globe	MOV	Elec.	Manual	Closed	Closed	Open	FAI	B,F,RM	15	Div II	14,15	21
2-70 . 8	Outside Outside	2'-0" 11'-2"	C C	No(29)	2RHS*MOV25A 2RHS*MOV15A	E12-F017A E12-F016A	Gate Gate	MOV MOV	Elec. Elec.	Manual Manual	Closed Closed	Closed Closed	Open Open	FAI FAI	RM RM	87 87	Div I Div I	13,15	21
2-70 . 8	Outside Outside	2'-0" 9'-6"	C C	No(29)	2RHS*MOV25B 2RHS*MOV15B	E12-F017B E12-F016B	Gate Gate	MOV MOV	Elec. Elec.	Manual Manual	Closed Closed	Closed Closed	Open Open	FAI FAI	RM RM	87 87	Div II Div II	13,15	21
2-70 . 9	Outside Inside	7'-0"	C C	No(29)	2RHS*MOV24A 2RHS*AOV16A	E12-F042A E12-F041A	Gate Check	MOV AOV	Elec. Process	Manual Air (Test only)	Closed Closed	Closed Closed	Open Open	FAI Closed flow	RM Reverse	19 N/A	Div I Div I	11,13, 15	
2-70 . 9	Outside Inside	6'-6"	C C	No(29)	2RHS*MOV24B 2RHS*AOV16B	E12-F042B E12-F041B	Gate Check	MOV AOV	Elec. Process	Manual Air (Test only)	Closed Closed	Closed Closed	Open Open	FAI Closed	RM Reverse flow	19 N/A	Div II Div II	11,13, 15	
2-70 . 9	Outside Inside	6'-6"	C C	No(29)	2RHS*MOV24C 2RHS*AOV16C	E12-F042C E12-F041C	Gate Check	MOV AOV	Elec. Process	Manual Air (Test only)	Closed Closed	Closed Closed	Open Open	FAI Closed	RM Reverse flow	19 N/A	Div II Div II	11,13, 15	

Table A.2.9. (Continued)

	Penetration No.	System Designation	GDC or Reg. Guide	ESF System	Fluid	Size (in)	FSAR Arrangement Figure(1)	Location of valve Inside/Outside Primary Containment	Length of Pipe - Containment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Number SWEC	Number GE	Type	Operator	Actuator Primary
*	Z-10A	RHS shutdown return Loop A to reactor recirc Loop A	55	No	Water	12	6.2-70 Sh. 13	Outside	6'-0"	C	No(29)	2RHS*MOV40A	E12-F053A	Globe	MOV	Elec.
								Inside		C		2RHS*AOV39A	E12-F050A	Check	AOV	Process
*		RHS shutdown cooling return line inboard valve bypass line	55	No	Water	2	6.2-70 Sh. 13	Inside		C		2RHS*MOV67A	E12-F099A	Globe	MOV	Elec.
*	Z-10B	RHS shutdown return Loop B to reactor recirc Loop B	55	No	Water	12	6.2-70 Sh. 13	Outside	6'-0"	C	No(29)	2RHS*MOV40B	E12-F053B	Globe	MOV	Elec.
								Inside		C		2RHS*AOV39B	E12-F050B	Check	AOV	Process
*		RHS shutdown cooling return line inboard valve bypass line	55	No	Water	2	6.2-70 Sh. 13	Inside		C		2RHS*MOV67B	E12-F099B	Globe	MOV	Elec.
*	Z-11	RHS shutdown supply from reactor recirc	55	No	Water	20	6.2-70 Sh. 14	Outside	6'-0"	C	No(29)	2RHS*MOV113	E12-F008	Gate	MOV	Elec.
								Inside		C		2RHS*MOV112	E12-F009	Gate	MOV	Elec.
								Inside		C		2RHS*RV152	-	Relief	N/A	Auto
E	Z-12	CSH suction from suppression pool	56	Yes	Water	20	6.2-70 Sh. 5	Outside	2'-2"	C C	Yes(30)	2CSH*MOV118	E22-F015	Gate	MOV	Elec.
E	Z-13	CSH test return to suppression	56	Yes	Water	12	6.2-70 Sh. 15	Outside	50'-0"	C	No(29)	2CSH*MOV111	E22-F023	Globe	MOV	Elec.
		HPCS min flow bypass		Yes	Water	4		Outside	45'-6"	C		2CSH*MOV105	E22-F012	Gate	MOV	Elec.

Location of valve Inside/ Outside Primary Contain-ment	Length of Pipe - Con-tainment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Number SWEC	Number GE	Valve(9) Type	Oper-ator	Actuator Mode Primary	Actuator Mode Secondary	Position Normal (3)	Position Shutdown	Position Post-Accident	Power Failure (10)	Isola-tion Signal (4)	Closure Time (5,6)	Power Source (7)	Notes	
Outside	6'-0"	C	No(29)	2RHS*MOV40A	E12-F053A	Globe	MOV	Elec.	Manual	Closed	Open	Closed	FAI	A,L,M, RM	25	Div I	11	
Inside		C		2RHS*AOV39A	E12-F050A	Check	AOV	Process	Air (Test only)	Closed	Open	Closed	Closed	Reverse flow	N/A	Div I		
Inside		C		2RHS*MOV67A	E12-F099A	Globe	MOV	Elec.	Manual	Closed	Closed	Closed	FAI	A,L,M, RM	9	Div I		
Outside	6'-0"	C	No(29)	2RHS*MOV40B	E12-F053B	Globe	MOV	Elec.	Manual	Closed	Open	Closed	FAI	A,L,M, RM	25	Div II	11	
Inside		C		2RHS*AOV39B	E12-F050B	Check	AOV	Process	Air (Test only)	Closed	Open	Closed	Closed	Reverse flow	N/A	Div II		
Inside		C		2RHS*MOV67B	E12-F099B	Globe	MOV	Elec.	Manual	Closed	Closed	Closed	FAI	A,L,M, RM	9	Div II		
Outside	6'-0"	C	No(29)	2RHS*MOV113	E12-F008	Gate	MOV	Elec.	Manual	Closed	Open	Closed	FAI	A,L,M, RM	27	Div I		
Inside		C		2RHS*MOV112	E12-F009	Gate	MOV	Elec.	Manual	Closed	Open	Closed	FAI	A,L,M, RM	27	Div II		
Inside		C		2RHS*RV152	-	Relief	N/A	Auto	N/A	Closed	Closed	Closed	Closed	N/A	N/A	N/A		
Outside	2'-2"	C C	Yes(30)	2CSH*MOV118	E22-F015	Gate	MOV	Elec.	Manual	Closed	Closed	Open	FAI	RM	18	Div III	13	21
Outside	50'-0"	C	No(29)	2CSH*MOV111	E22-F023	Globe	MOV	Elec.	Manual	Closed	Closed	Closed	FAI	B,F,RM	60	Div III		21
Outside	45'-6"	C		2CSH*MOV105	E22-F012	Gate	MOV	Elec.	Manual	Closed	Closed	Closed	FAI	RM	5	Div III		21

Table A.2.9. (Continued)

	Pene-tration No.	System Designation	GDC or Reg. Guide	ESF System	Fluid	Size (in)	FSAR Arrange-ment Figure[1]	Location of valve Inside/ Outside Primary Contain-ment	Length of Pipe - Con-tainment to Outside Isolation Valve	Type Test [1]	Potential Bypass Leakage Path	Number SWEC	Number GE	Valv… Type	Oper-ator	Actuator Mode Primary	Actuator Mode Secondary	Normal [3]	Shut…
*	Z-14	CSH to RPV	55	Yes	Water	12	6.2-70 Sh. 9	Inside		C	No[29]	2CSH*AOV108	E22-F005	Check	AOV	Process	Air (Test only)	Closed	Clo…
								Outside	2'-0"	C		2CSH*MOV107	E22-F004	Gate	MOV	Elec.	Manual	Closed	Clos
E	Z-15	CSL suction from suppres-sion pool	56	Yes	Water	20	6.2-70 Sh. 4	Outside	7'-9"	C	No[29]	2CSL*MOV112	E21-F001	Butter-fly	MOV	Elec.	Manual	Open	Open
*	Z-16	CSL to RPV	55	Yes	Water	12	6.2-70 Sh. 10	Inside		C	No[29]	2CSL*AOV101	E21-F006	Check	AOV	Process	Air (Test only)	Closed	Clos
								Outside	1'-0"	C		2CSL*MOV104	E21-F005	Gate	MOV	Elec.	Manual	Closed	Clos
E	Z-17	ICS suction from suppres-sion pool	56	Yes	Water	6	6.2-70 Sh. 5	Outside	0'-9"	C	Yes[30]	2ICS*MOV136	E21-F031	Gate	MOV	Elec.	Manual	Closed	Clos
E	Z-18	ICS minimum flow to sup-pression pool	56	Yes	Water	2	6.2-70 Sh. 11	Outside	0'-6"	C	No[29]	2ICS*MOV143	E21-F019	Globe	MOV	Elec.	Manual	Closed	Clos
E	Z-19	ICS turbine exhaust to suppression pool	56	Yes	Steam	12	6.2-70 Sh. 12	Outside	1'-6"	C	No[29]	2ICS*MOV122	E21-F068	Gate	MOV	Elec.	Manual	Open	Open
	Z-20	Spare		No		3/4				A									

of :on- : to le .on	Type Test (1)	Potential Bypass Leakage Path	Number SWEC	Number GE	Valve(9) Type	Oper-ator	Actuator Mode Primary	Actuator Mode Secondary	Position Normal (3)	Position Shutdown	Position Post-Accident	Power Failure (10)	Isola-tion Signal (4)	Closure Time (5,6)	Power Source (7)	Notes	
	C	No(29)	2CSH*AOV108	E22-F005	Check	AOV	Process	Air (Test only)	Closed	Closed	Open	Closed	Reverse flow	N/A	Div III	11,13	
	C		2CSH*MOV107	E22-F004	Gate	MOV	Elec.	Manual	Closed	Closed	Open	FAI	PM	12	Div III		
	C	No(29)	2CSL*MOV112	E21-F001	Butter-fly	MOV	Elec.	Manual	Open	Open	Open	FAI	RM	90	Div I	13	21
	C	No(29)	2CSL*AOV101	E21-F006	Check	AOV	Process	Air (Test only)	Closed	Closed	Open	Closed	Reverse flow	N/A	Div I	11,13	
	C		2CSL*MOV104	E21-F005	Gate	MOV	Elec.	Manual	Closed	Closed	Open	FAI	RM	16	Div I		
	C	Yes(30)	2ICS*MOV136	E21-F031	Gate	MOV	Elec.	Manual	Closed	Closed	Open	FAI	RM	19	125VDC		21
	C	No(29)	2ICS*MOV143	E21-F019	Globe	MOV	Elec.	Manual	Closed	Closed	Closed	FAI	RM	5	125VDC		21
	C	No(29)	2ICS*MOV122	E21-F068	Gate	MOV	Elec.	Manual	Open	Open	Open	FAI	RM	85	125VDC	16	21

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Table A.2.9. (Continued)

	Penetration No.	System Designation	GDC or Reg. Guide	ESF System	Fluid	Size (in)	FSAR Arrangement Figure(1)	Location of valve Inside/Outside Primary Containment	Length of Pipe - Containment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Number SWEC	Number GE	Type	Operator	Pr
A	Z-21A	Steam to ICS turbine and RHS heat exchangers	55	Yes	Steam	10	6.2-70 Sh. 16	Outside Inside	0'-9"	C C	No(29)	2ICS*MOV121 2ICS*MOV128	E51-F064 E51-F063	Gate Gate	MOV MOV	El El
A		ICS turbine steam supply bypass to inboard isolation valve			Steam			Inside		C	No(29)	2ICS*MOV170	E51-F076	Globe	MOV	El
	Z-21B	Spare		No		4				A						
*	Z-22	ICS to RPV	55	Yes	Water	6	6.2-70 Sh. 17	Outside Inside Outside	0'-6" 4'-3"	C C C	No(29)	2ICS*AOV156 2ICS*AOV157 2ICS*MOV126	E51-F065 E51-F066 E12-F013	Check Check Gate	AOV AOV MOV	Pr Pr El
*		RHR reactor head spray			Water	6	6.2-70 Sh. 17	Outside	29'-5"	C		2RHS*MOV104	E12-F023	Globe	MOV	El
A	Z-23	WCS supply from RCS & RPV	55	No	Water Water	8 8	6.2-70 Sh. 18	Inside Outside	 1'-3"	C C	Yes(30)	2WCS*MOV102 2WCS*MOV112	G33-F001 G33-F004	Globe Globe	MOV MOV	El EL
	Z-24	Spare		No		3				A						
B	Z-25	RDS lines to RPV 53 Insert 53 Withdrawal		Yes	Water	1 3/4	N/A	Outside Outside	125'-0" 125'-0"		No(29)					
B	Z-26	RDS lines to RPV 39 Insert 39 Withdrawal		Yes	Water	1 3/4	N/A	Outside Outside	125'-0" 125'-0"		No(29)					
B	Z-27	RDS lines to RPV 54 Insert 54 Withdrawal		Yes	Water	1 3/4	N/A	Outside Outside	125'-0" 125'-0"		No(29)					

e- (1)	Location of valve Inside/ Outside Primary Contain- ment	Length of Pipe - Con- tainment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Number SWEC	Number GE	Type	Oper- ator	Actuator Mode Primary	Actuator Mode Secondary	Valve(9) Position Normal (3)	Valve(9) Position Shutdown	Valve(9) Position Post- Accident	Power Failure (10)	Isola- tion Signal (4)	Closure Time (5,6)	Power Source (7)	Notes	
	Outside	0'-9"	C	No(29)	2ICS*MOV121	E51-F064	Gate	MOV	Elec.	Manual	Open	Closed	Open	FAI	M,BB,CC, DD,K,H,RM	14	Div I		25
	Inside		C		2ICS*MOV128	E51-F063	Gate	MOV	Elec.	Manual	Open	Closed	Open	FAI	M,BB,CC, DD,K,H,RM	14	Div. II		
	Inside		C	No(29)	2ICS*MOV170	E51-F076	Globe	MOV	Elec.	Manual	Closed	Closed	Closed	FAI	M,BB,CC, DD,K,H,RM	5	Div. II		25
			A																
	Outside	0'-6"	C	No(29)	2ICS*AOV156	E51-F065	Check	AOV	Process	Air (Test only)	Closed	Open	Open	Closed	Rev flow	N/A	125VDC		
	Inside		C		2ICS*AOV157	E51-F066	Check	AOV	Process	Air (Test only)	Closed	Open	Open	Closed	Rev flow	N/A	125VDC		
	Outside	4'-3"	C		2ICS*MOV126	E12-F013	Gate	MOV	Elec.	Manual	Closed	Closed	Open	FAI	RM	12			
	Outside	29'-5"	C		2RHS*MOV104	E12-F023	Globe	MOV	Elec.	Manual	Closed	Open	Closed	FAI	A,L,M,CC RM,DD	32	Div I		
	Inside		C	Yes(30)	2WCS*MOV102	G33-F001	Globe	MOV	Elec.	Manual	Open	Open	Closed	FAI	B,J,U,S,RM,DD	13	Div II		25
	Outside	1'-3"	C		2WCS*MOV112	G33-F004	Globe	MOV	Elec.	Manual	Open	Open	Closed	FAI	B,J,U,S,W, RM,DD	12	Div I		
			A																
	Outside	125'-0"		No(29)															
	Outside	125'-0"									See Note 17								
	Outside	125'-0"		No(29)															
	Outside	125'-0"									See Note 17								
	Outside	125'-0"		No(29)															
	Outside	125'-0"									See Note 17								

Table A.2.9 (Continued)

	Pene-tration No.	System Designation	GDC or Reg. Guide	ESF System	Fluid	Size (in)	FSAR Arrange-ment Figure(1)	Location of valve Inside/ Outside Primary Contain-ment	Length of Pipe - Con-tainment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Number SWEC	Number GE	Type	Oper-ator	Actuator Mode Primary	Actuator Mode Secondary	Val Normal (3)	Val Shu
B	Z-28	RDS lines to RPV		Yes							No(29)							See Note 1	
		39 Insert			Water	1 3/4	N/A	Outside	125'-0"										
		39 With-drawal						Outside	125'-0"										
B	Z-29	SLCS to RPV	55	Yes	Boron solu-tion	1 1/2	6.2-70 Sh. 43	Inside		C	No(31)	2SLS*V10	C41-F007	Check	N/A	Process	N/A	Closed	Cl
								Outside	2'-10"	C		2SLS*MOV5A	C41-F006A	Stop check globe	MOV	Elec.	Manual	Closed	Cl
								Outside	3'-10"	C		2SLS*MOV5B	C41-F006B	Stop check globe	MOV	Elec.	Manual	Closed	Cl
	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	2'-4"	C	No(31)	N/A	C51-J004	Ball	SOV	Elec.	N/A	Closed	Cl
								Outside		C		N/A	C51-J004	Shear	N/A	N/A	N/A	Open	Op
B	Z-31B	TIP drive guide tube to RPV	57	No	Note 19	1 1/2	6.2-70 Sh. 19	Outside	5'-4"	C	No(31)	N/A	C51-J004	Ball	SOV	Elec.	N/A	Closed	Cl
								Outside		C		N/A	C51-J004	Shear	N/A	N/A	N/A	Open	Op
B	Z-31C	TIP drive guide tube to RPV	57	No	Note 19	1 1/2	6.2-70 Sh. 19	Outside	2'-4"	C	No(31)	N/A	C51-J004	Ball	SOV	Elec.	N/A	Closed	Cl
								Outside		C		N/A	C51-J004	Shear	N/A	N/A	N/A	Open	Op
B	Z-31D	TIP drive guide tube to RPV	57	No	Note 19	1 1/2	6.2-70 Sh.19	Outside	2'-4"	C	No(31)	N/A	C51-J004	Ball	SOV	Elec.	N/A	Closed	Cl
								Outside		C		N/A	C51-J004	Shear	N/A	N/A	N/A	Open	Op
B	Z-31E	TIP drive guide tube to RPV	57	No	Note 19	1 1/2	6.2-70 Sh. 19	Outside	2'-7"	C	No(31)	N/A	C51-J004	Ball	SOV	Elec.	N/A	Closed	Cl
								Outside		C		N/A	C51-J004	Shear	N/A	N/A	N/A	Open	Op
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(31)	2GSN*V168	-	Check	N/A	Process	N/A	Open	Cl
								Outside	6'-3"	C		2GSN*V169	-	Check	N/A	Process	N/A	Open	Cl
								Inside	-	C		2GSN*V170	-	Check	N/A	Process	N/A	Open	Cl
E	Z-33A	CCP supply to RCS Pump A	56	No	Water	4	6.2-70 Sh. 20	Inside		C	No(31)	2CCP*MOV94A	-	Gate	MOV	Elec.	Manual	Open	Op
								Outside	7'-0"	C		2CCP*MOV17A	-	Gate	MOV	Elec.	Manual	Open	Op

›f ›n- to e ›n	Type Test (1)	Potential Bypass Leakage Path	Number SWEC	Number GE	Valve (9) Type	Operator	Actuator Mode Primary	Actuator Mode Secondary	Position Normal (3)	Position Shutdown	Position Post-Accident	Power Failure (10)	Isolation Signal (4)	Closure Time (5,6)	Power Source (7)	Notes	
		No(29)							See Note 17								
	C	No(31)	2SLS*V10	C41-F007	Check	N/A	Process	N/A	Closed	Closed	Closed	N/A	Reverse flow	N/A	N/A		
	C		2SLS*MOV5A	C41-F006A	Stop check globe	MOV	Elec.	Manual	Closed	Closed	Closed	Closed	Reverse flow	N/A	N/A		
	C		2SLS*MOV5B	C41-F006B	Stop check globe	MOV	Elec.	Manual	Closed	Closed	Closed	Closed	Reverse flow	N/A	N/A		
	A																
	A																
	C	No(31)	N/A	C51-J004	Ball	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,RM	N/A	120 VAC	18,19,	17
	C		N/A	C51-J004	Shear	N/A	N/A	N/A	Open	Open	Open	Open	RM	N/A	125 VDC	28,34	
	C	No(31)	N/A	C51-J004	Ball	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,RM	N/A	120 VAC	18,19	17
	C		N/A	C51-J004	Shear	N/A	N/A	N/A	Open	Open	Open	Open	RM	N/A	125 VDC	28,34	
	C	No(31)	N/A	C51-J004	Ball	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,RM	N/A	120 VAC	18,19	17
	C		N/A	C51-J004	Shear	N/A	N/A	N/A	Open	Open	Open	Open	RM	N/A	125 VDC	28,34	
	C	No(31)	N/A	C51-J004	Ball	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,RM	N/A	120 VAC	18,19	17
	C		N/A	C51-J004	Shear	N/A	N/A	N/A	Open	Open	Open	Open	RM	N/A	125 VDC	28,34	
	C	No(31)	N/A	C51-J004	Ball	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,RM	N/A	120 VAC	18,19,	17
	C		N/A	C51-J004	Shear	N/A	N/A	N/A	Open	Open	Open	Open	RM	N/A	125 VDC	28,34	
	C	No(31)	2GSN*V168	-	Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow	N/A	N/A	34	17
	C		2GSN*V169	-	Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow	N/A	N/A		
	C		2GSN*V170	-	Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow	N/A	N/A		
	C	No(31)	2CCP*MOV94A	-	Gate	MOV	Elec.	Manual	Open	Open	Closed	FAI	B,F,RM	20	Div II	6	
	C		2CCP*MOV17A	-	Gate	MOV	Elec.	Manual	Open	Open	Closed	FAI	B,F,RM	20	Div I		

Table A.2.9 (Continued)

	Penetration No.	System Designation	GDC or Reg. Guide	ESP System	Fluid	Size (in)	FSAR Arrangement Figure(1)	Location of Valve Inside/Outside Primary Containment	Length of Pipe - Containment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path(2)	Number SWEC	Number GE	Type	Operator	Actuator Mode Primary	Actuator Mode Secon
E	Z-33B	CCP to RCS Pump B	56	No	Water	4	6.2-70 Sh. 20	Inside		C	No(31)	2CCP*MOV94B	-	Gate	MOV	Elec.	Manua
								Outside	7'-0"	C		2CCP*MOV17B	-	Gate	MOV	Elec.	Manua
								Inside		N/A		2CCP*RV170	-	Relief	N/A	Auto	N/A
E	Z-34A	CCP return from RCS Pump A	56	No	Water	4	6.2-70 Sh. 21	Inside		C	No(31)	2CCP*MOV16A	-	Gate	MOV	Elec.	Manua
								Outside	7'-0"	C		2CCP*MOV15A	-	Gate	MOV	Elec.	Manua
E	Z-34B	CCP return from RCS Pump B	56	No	Water	4	6.2-70 Sh. 21	Inside		C	No(31)	2CCP*MOV16B	-	Gate	MOV	Elec.	Manua
								Outside	7'-0"	C		2CCP*MOV15B	-	Gate	MOV	Elec.	Manua
								Inside		N/A		2CCP*RV171	-	Relief	N/A	Auto	N/A
	Z-35	Spare				4				A							
E	Z-36	Service air to drywell	56	No	Air	2	6.2-70 Sh. 22	Outside	0'-7"	C	No(31)	2SAS*HCV161	-	Globe	Manual	Manual	N/A
								Inside				2SAS*HCV163	-	Globe	Manual	Manual	N/A
E	Z-37	Breathing air to drywell	56	No	Air	2	6.2-70 Sh. 22	Outside	0'-7"	C	No(31)	2AAS*HCV134	-	Globe	Manual	Manual	N/A
								Inside		C		2AAS*HCV136	-	Globe	Manual	Manual	N/A
B	Z-38A	RDS to recirc pump A seal	55	No	Water	3/4	6.2-70 Sh. 23	Inside		C	No(29)	2RCS*V60A	B35-F013A	Check	N/A	Process	N/A
								Outside	0'-0"	C		2RCS*V90A	B35-F009A	Check	N/A	Process	N/A
								Outside	33'-0"	C		2RCS*V59A	B35-F017A	Check	N/A	Process	N/A
B	Z-38B	RDS to recirc Pump A seal	55	No	Water	3/4	6.2-70 Sh. 23	Inside		C	No(29)	2RCS*V60B	B35-F013B	Check	N/A	Process	N/A
								Outside	0'-0"	C		2RCS*V90B	B35-F009B	Check	N/A	Process	N/A
								Outside	31'-0"	C		2RCS*V59B	B35-F017B	Check	N/A	Process	N/A
E	Z-39	Floor drains from drywell	56	No	Air	6	6.2-70 Sh. 24	Inside		C	Yes(30)	2DFR*MOV121	-	Gate	MOV	Elec.	Manua
								Outside	1'-6"	C		2DFR*MOV120	-	Gate	MOV	Elec.	Manua
E	Z-40	Equipment drains from drywell	56	No	Water	4	6.2-70 Sh. 24	Inside		C		2DER*MOV119	-	Gate	MOV	Elec.	Manua
								Outside	4'-2"	C	Yes(30)	2DER*MOV120	-	Gate	MOV	Elec.	Manua

FSAR Arrange-ment Figure(1)	Location of valve Inside/ Outside Primary Contain-ment	Length of Pipe - Con-tainment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path(2)	Valve(9) Number SWEC	Number GE	Type	Oper-ator	Actuator Mode Primary	Actuator Mode Secondary	Position Normal (3)	Position Shutdown	Position Post-Accident	Position Power Failure(10)	Isola-tion Signal (4)	Closure Time (5,6)	Power Source (7)	Notes
·70	Inside		C	No(31)	2CCP*MOV94B	-	Gate	MOV	Elec.	Manual	Open	Open	Closed	FAI	B,F,RM	20	Div II	
20	Outside	7'-0"	C		2CCP*MOV17B	-	Gate	MOV	Elec.	Manual	Open	Open	Closed	FAI	B,F,RM	20	Div I	
	Inside		N/A		2CCP*RV170	-	Relief	N/A	Auto	N/A	Closed	Closed	Closed	N/A	N/A	N/A	N/A	
70	Inside		C	No(31)	2CCP*MOV16A	-	Gate	MOV	Elec.	Manual	Open	Open	Closed	FAI	B,F,RM	20	Div II	
21	Outside	7'-0"	C		2CCP*MOV15A	-	Gate	MOV	Elec.	Manual	Open	Open	Closed	FAI	B,F,RM	20	Div I	
70	Inside		C	No(31)	2CCP*MOV16B	-	Gate	MOV	Elec.	Manual	Open	Open	Closed	FAI	B,F,RM	20	Div II	
21	Outside	7'-0"	C		2CCP*MOV15B	-	Gate	MOV	Elec.	Manual	Open	Open	Closed	FAI	B,F,RM	20	Div I	
	Inside		N/A		2CCP*RV171	-	Relief	N/A	Auto	N/A	Closed	Closed	Closed	N/A	N/A	N/A	N/A	
			A															
70	Outside	0'-7"	C	No(31)	2SAS*HCV161	-	Globe	Manual	Manual	N/A	Closed	Open	Closed	N/A	LMC,LC	N/A	Div I	
22	Inside				2SAS*HCV163	-	Globe	Manual	Manual	N/A	Closed	Open	Closed	N/A	LMC,LC	N/A	Div II	
70	Outside	0'-7"	C	No(31)	2AAS*HCV134	-	Globe	Manual	Manual	N/A	Closed	Open	Closed	N/A	LMC,LC	N/A	Div I	
22	Inside		C		2AAS*HCV136	-	Globe	Manual	Manual	N/A	Closed	Open	Closed	N/A	LMC,LC	N/A	Div II	
0 3	Inside		C	No(29)	2RCS*V60A	B35-F013A	Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow	N/A	N/A	
	Outside	0'-0"	C		2RCS*V90A	B35-F009A	Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow	N/A		
	Outside	33'-0"	C		2RCS*V59A	B35-F017A	Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow	N/A		25
) 3	Inside		C	No(29)	2RCS*V60B	B35-F013B	Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow	N/A	N/A	
	Outside	0'-0"	C		2RCS*V90B	B35-F009B	Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow	N/A		
	Outside	31'-0"	C		2RCS*V59B	B35-F017B	Check	N/A	Process	N/A	Open	Closed	Closed	N/A	Reverse flow	N/A		25
	Inside		C	Yes(30)	2DFR*MOV121	-	Gate	MOV	Elec.	Manual	Open	Closed	Closed	FAI	B,F,RM	28	Div II	
	Outside	1'-6"	C		2DFR*MOV120	-	Gate	MOV	Elec.	Manual	Open	Closed	Closed	FAI	B,F,RM	28	Div I	
	Inside		C		2DER*MOV119	-	Gate	MOV	Elec.	Manual	Open	Closed	Closed	FAI	B,F,RM	22	Div II	
	Outside	4'-2"	C	Yes(30)	2DER*MOV120	-	Gate	MOV	Elec.	Manual	Open	Closed	Closed	FAI	B,F,RM	22	Div I	

Table A.2.9 (Continued)

	Pene-tration No.	System Designation	GDC or Reg. Guide	ESF System	Fluid	Size (in)	FSAR Arrange-ment Figure(1)	Location of Valve Inside/Outside Primary Contain-ment	Length of Pipe - Contain-ment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Valve(9 Number SWEC	Number GE	Type	Oper-ator	Actuator Mode Primary	Actuator Mode Secondary	Normal (3)	Shutdow
E	Z-41	Reactor coolant recirc to sample cooler	55	No	Water	3/4	6.2-70	Inside		C	No(31)	2RCS*SOV104	B35-F019	Globe	SOV	Elec.	N/A	Closed	Closed
							Sh. 25	Outside	0'-0"	C		2RCS*SOV105	B35-F020	Globe	SOV	Elec.	N/A	Closed	Closed
E	Z-42A	Fire protection for reactor recirc pump	56	No	Water	2	6.2-70	Inside		C	No(31)	2FPW*SOV219	-	Globe	SOV	Elec.	N/A	Closed	Closed
							Sh. 26	Outside	3'-0"	C		2FPW*SOV218	-	Globe	SOV	Elec.	N/A	Closed	Closed
E	Z-42B	Fire protection water for reac-tor recirc pump	56	No	Water	2	6.2-70	Inside		C	No(31)	2FPW*SOV221	-	Globe	SOV	Elec.	N/A	Closed	Closed
							Sh. 26	Outside	3'-0"	C		2FPW*SOV220	-	Globe	SOV	Elec.	N/A	Closed	Closed
E	Z-43	Drywell floor drains	56	No	Water	6	6.2-70	Inside		C	Yes(30)	2DFR*MOV140	-	Gate	MOV	Elec.	Manual	Open	Closed
							Sh. 27	Outside	20'-10"	C		2DFR*MOV139	-	Gate	MOV	Elec.	Manual	Open	Closed
	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-44E	Service air to drywell	56	No	Air	2	6.2-70	Outside	0'-5"	C	No(31)	2SAS*HCV160	-	Globe	Manual	Manual	N/A	Closed	Open
							Sh. 22	Inside		C		2SAS*HCV162	-	Globe	Manual	Manual	N/A	Closed	Open
E	Z-44F	Breathing air to drywell	56	No	Air	2	6.2-70	Outside	0'-5"	C	No(31)	2AAS*HCV135	-	Globe	Manual	Manual	N/A	Closed	Open
							Sh. 22	Inside		C		2AAS*HCV137	-	Globe	Manual	Manual	N/A	Closed	Open
E	Z-45	Equipment drain tank (2DER-TK1) vent to drywell	56	No	Air	2	6.2-70	Inside	0'-0"	C	Yes(30)	2DER*MOV130	-	Globe	MOV	Elec.	Manual	Open	Closed
							Sh. 27	Outside		C		2DER*MOV131	-	Globe	MOV	Elec.	Manual	Open	Closed
E	Z-46A	CCP supply to drywell space cooler	56	No	Water	8	6.2-70	Inside		C	No(31)	2CCP*MOV273	-	Gate	MOV	Elec.	Manual	Open	Open
							Sh. 28	Outside	7'-0"	C		2CCP*MOV265	-	Gate	MOV	Elec.	Manual	Open	Open

Valve(9)													
Number				Actuator Mode		Position				Isola-tion Signal (4)	Closure Time (5,6)	Power Source (7)	Notes
SWEC	GE	Type	Oper-ator	Primary	Secondary	Normal (3)	Shutdown	Post-Accident	Power Failure(10)				
2RCS*SOV104	B35-F019	Globe	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,C,RM	N/A	Div II	
2RCS*SOV105	B35-F020	Globe	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,C,RM	N/A	Div I	
2FPW*SOV219	-	Globe	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,RM	N/A	Div II	
2FPW*SOV218	-	Globe	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,RM	N/A	Div I	
2FPW*SOV221	-	Globe	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,RM	N/A	Div II	
2FPW*SOV220	-	Globe	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,RM	N/A	Div I	
2DFR*MOV140	-	Gate	MOV	Elec.	Manual	Open	Closed	Closed	FAI	B,F,RM	13	Div II	
2DFR*MOV139	-	Gate	MOV	Elec.	Manual	Open	Closed	Closed	FAI	B,F,RM	13	Div I	
2SAS*HCV160	-	Globe	Manual	Manual	N/A	Closed	Open	Closed	N/A	LMC,LC	N/A	Div I	
2SAS*HCV162	-	Globe	Manual	Manual	N/A	Closed	Open	Closed	N/A	LMC,LC	N/A	Div II	
2AAS*HCV135	-	Globe	Manual	Manual	N/A	Closed	Open	Closed	N/A	LMC,LC	N/A	Div I	
2AAS*HCV137	-	Globe	Manual	Manual	N/A	Closed	Open	Closed	N/A	LMC,LC	N/A	Div II	
2DER*MOV130	-	Globe	MOV	Elec.	Manual	Open	Closed	Closed	FAI	B,F,RM	9	Div II	
2DER*MOV131	-	Globe	MOV	Elec.	Manual	Open	Closed	Closed	FAI	B,F,RM	9	Div I	
2CCP*MOV273	-	Gate	MOV	Elec.	Manual	Open	Open	Closed	FAI	B,F,RM	36	Div II	
2CCP*MOV265	-	Gate	MOV	Elec.	Manual	Open	Open	Closed	FAI	B,F,RM	38	Div I	

Table A.2.9 (Continued)

	Penetration No.	System Designation	GDC or Reg. Guide	ESF System	Fluid	Size (in)	FSAR Arrangement Figure(1)	Location of Valve Inside/Outside Primary Containment	Length of Pipe - Containment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Number SWEC	Number GE
	Z-46B	Capped spare				4				A			
E	Z-46C	Fire protection water for containment hose reel standpipe						See Note 20			No(31)		
	Z-46D	Capped spare				4				A			
E	Z-47	CCP return from drywell space cooler	57	No(31)	Water	8	6.2-70 Sh. 28	Inside		C	No(31)	2CCP*MOV122	-
								Outside	7'-3"	C		2CCP*MOV124	-
E	Z-48	Purge exhaust from drywell	56	No	Air	14	6.2-70 Sh. 29	Inside	-	C	No(31)	2CPS*AOV108	-
								Outside	7'-4"	C		2CPS*AOV110	-
E	Z-49	Purge inlet to drywell	56	No	Air/N_2	14	6.2-70 Sh. 29	Inside	-	C	Yes	2CPS*AOV106	-
								Outside	4'-0"	C		2CPS*AOV104	-
E	Z-50	Purge inlet to wetwell	56	No	Air/N_2	12	6.2-70 Sh. 29	Inside	-	C	Yes	2CPS*AOV107	-
								Outside	4'-3"	C		2CPS*AOV105	-
E	Z-51	Purge exhaust from wetwell	56	No	Air	12	6.2-70 Sh. 29	Inside	-	C	No(31)	2CPS*AOV109	-
								Outside	6'-6"	C		2CPS*AOV111	-
	Z-52A	Capped spare				1				A			
	Z-52B	Capped spare				1				A			
E	Z-53A	Instrument air to ADS valve accumulators	56	No	N_2	1 1/2	6.2-70 Sh. 30	Outside	1'-0"	C		2IAS*SOV164	
								Inside		C	Yes(30)	2IAS*V448	

R ge- t e(1)	Location of Valve Inside/ Outside Primary Contain- ment	Length of Pipe - Con- tainment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Valve(9) Number SWEC	GE	Type	Oper- ator	Actuator Mode Primary	Secondary	Position Normal (3)	Shutdown	Post- Accident	Power Failure(10)	Isola- tion Signal (4)	Closure Time (5,6)	Power Source (7)	Notes	
			A																
	See Note 20			No(31)															
			A																
0	Inside		C	No(31)	2CCP*MOV122	-	Gate	MOV	Elec.	Manual	Open	Open	Closed	FAI	B,F,RM	38	Div II		
8	Outside	7'-3"	C		2CCP*MOV124	-	Gate	MOV	Elec.	Manual	Open	Open	Closed	FAI	B,F,RM	36	Div I		
0 9	Inside	-	C	No(31)	2CPS*AOV108	-	Butter- fly	AOV	Pneu- matic	Manual	Closed	Closed	Closed	Closed	B,F,Y,RM	5	Div II		
	Outside	7'-4"	C		2CPS*AOV110	-	Butter- fly	AOV	Pneu- matic	Manual	Closed	Closed	Closed	Closed	B,F,Y,RM	5	Div I		
0 9	Inside	-	C	Yes	2CPS*AOV106	-	Butter- fly	AOV	Pneu- matic	Manual	Closed	Closed	Closed	Closed	B,F,Y,RM	5	Div II	21	| 21
	Outside	4'-0"	C		2CPS*AOV104	-	Butter- fly	AOV	Pneu- matic	Manual	Closed	Closed	Closed	Closed	B,F,Y,RM	5	Div I		
0 9	Inside	-	C	Yes	2CPS*AOV107	-	Butter- fly	AOV	Pneu- matic	Manual	Closed	Closed	Closed	Closed	B,F,Y,RM	5	Div II		| 21
	Outside	4'-3"	C		2CPS*AOV105	-	Butter- fly	AOV	Pneu- matic	Manual	Closed	Closed	Closed	Closed	B,F,Y,RM	5	Div I		
0 9	Inside	-	C	No(31)	2CPS*AOV109	-	Butter- fly	AOV	Pneu- matic	Manual	Closed	Closed	Closed	Closed	B,F,Y,RM	5	Div II		
	Outside	6'-6"	C		2CPS*AOV111	-	Butter- fly	AOV	Pneu- matic	Manual	Closed	Closed	Closed	Closed	B,F,Y,RM	5	Div I		
			A																
			A																
)	Outside	1'-0"	C		2IAS*SOV164		Globe	SOV	Elec.	N/A	Open	Open	Open	Closed	B,F,RM	N/A	Div I		
)	Inside		C	Yes(30)	2IAS*V448		Check	N/A	Process	N/A	Open	Open	Open	N/A	Reverse flow	N/A	N/A		

Table A.2.9 (Continued)

	Pene-tration No.	System Designation	GDC or Reg. Guide	ESF System	Fluid	Size (in)	FSAR Arrange-ment Figure(1)	Location of valve Inside/ Outside Primary Contain-ment	Length of Pipe - Con-tainment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Valv Number SWEC	Number GE	Type	Oper-ator	Actuator Mode Primary	Actuator Mode Secondary	Normal (3)	Shut
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(30)	2IAS*SOV165 2IAS*V449	- -	Globe Check	SOV N/A	Elec. Process	N/A N/A	Open Open	Ope Ope
E	Z-53C	Instrument air to MSRV accumu-lator tank	56	No	N_2	1 1/2	6.2-70 Sh. 30	Outside Inside	1'-0"	C C	Yes(30)	2IAS*SOV166 2IAS*SOV184	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Ope Ope
	Z-54A	Capped spare				3				A									
E	Z-55A	Hydrogen recom-biner 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	MOV MOV	Elec. Elec.	Manual Manual	Closed Closed	Clo Clo
E	Z-55B	Hydrogen recom-biner 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	MOV MOV	Elec. Elec.	Manual Manual	Closed Closed	Clo Clo
E	Z-56A	Hydrogen recom-biner 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	MOV MOV	Elec. Elec.	Manual Manual	Closed Closed	Clo Clo
E	Z-56B	Hydrogen recom-biner 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	MOV MOV	Elec. Elec.	Manual Manual	Closed Closed	Clo Clo
E	Z-57A	Hyrdogen recom-biner 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	MOV MOV	Elec. Elec.	Manual Manual	Closed Closed	Clo Clo
E	Z-57B	Hyrodgen recom-biner 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	MOV MOV	Elec. Elec.	Manual Manual	Closed Closed	Clo Clo
E	Z-58	Containment purge to dry-well	56	No	Air	2	6.2-70 Sh. 29	Inside Outside	3'-4"	C C	Yes	2CPS*SOV122 2CPS*SOV120	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Closed Closed	Clo Clo

otential Bypass eakage Path	Valve(9) Number SWEC	GE	Type	Operator	Actuator Mode Primary	Secondary	Position Normal (3)	Shutdown	Post-Accident	Power Failure(10)	Isolation Signal (4)	Closure Time (5,6)	Power Source (7)	Notes
Yes(30)	2IAS*SOV165	-	Globe	SOV	Elec.	N/A	Open	Open	Open	Closed	B,F,RM	N/A	Div II	
	2IAS*V449	-	Check	N/A	Process	N/A	Open	Open	Open	N/A	Reverse flow	N/A	N/A	
Yes(30)	2IAS*SOV166	-	Globe	SOV	Elec.	N/A	Open	Open	Closed	Closed	B,F,RM	N/A	Div I	
	2IAS*SOV184	-	Globe	SOV	Elec.	N/A	Open	Open	Closed	Closed	B,F,RM	N/A	Div II	
No(31)	2HCS*MOV4A	-	Globe	MOV	Elec.	Manual	Closed	Closed	Open	FAI	B,F,RM	19	Div I	12,
	2HCS*MOV1A	-	Globe	MOV	Elec.	Manual	Closed	Closed	Open	FAI	B,F,RM	19	Div I	22
No(31)	2HCS*MOV4B	-	Globe	MOV	Elec.	Manual	Closed	Closed	Open	FAI	B,F,RM	19	Div II	12,
	2HCS*MOV1B	-	Globe	MOV	Elec.	Manual	Closed	Closed	Open	FAI	B,F,RM	19	Div II	22
No(31)	2HCS*MOV6A	-	Globe	MOV	Elec.	Manual	Closed	Closed	Open	FAI	B,F,RM	19	Div I	12,
	2HCS*MOV3A	-	Globe	MOV	Elec.	Manual	Closed	Closed	Open	FAI	B,F,RM	19	Div I	22
No(31)	2HCS*MOV6B	-	Globe	MOV	Elec.	Manual	Closed	Closed	Open	FAI	B,F,RM	19	Div II	12,
	2HCS*MOV3B	-	Globe	MOV	Elec.	Manual	Closed	Closed	Open	FAI	B,F,RM	19	Div II	22
No(31)	2HCS*MOV5A	-	Globe	MOV	Elec.	Manual	Closed	Closed	Open	FAI	B,F,RM	19	Div I	12,
	2HCS*MOV2A	-	Globe	MOV	Elec.	Manual	Closed	Closed	Open	FAI	B,F,RM	19	Div I	22
No(31)	2HCS*MOV5B	-	Globe	MOV	Elec.	Manual	Closed	Closed	Open	FAI	B,F,RM	19	Div II	12,
	2HCS*MOV2B	-	Globe	MOV	Elec.	Manual	Closed	Closed	Open	FAI	B,F,RM	19	Div II	22
Yes	2CPS*SOV122	-	Globe	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,Y RM	N/A	Div II	
	2CPS*SOV120	-	Globe	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,Y RM	N/A	Div I	

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Table A.2.9 (Continued)

	Pene-tration No.	System Designation	GDC or Reg. Guide	ESF System	Fluid	Size (in)	FSAR Arrange-ment Figure(1)	Location of valve Inside/Outside Primary Contain-ment	Length of Pipe - Con-tainment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Number SWEC	Number GE	Type	Oper-ator	Actuator Mode Primary	Actuator Mode Secondary
E	Z-59	Containment purge to wet-well	56	No	Air	2	6.2-70 Sh. 29	Inside		C	Yes	2CPS*SOV121	-	Globe	SOV	Elec.	N/A
								Outside	14'-6"	C		2CPS*SOV119	-	Globe	SOV	Elec.	N/A
E	Z-60A	CMS from dry-well	56	No	Air	3/4	6.2-70 Sh. 32	Inside Outside	1'-2"	C C	No(31)	2CMS*SOV61A 2CMS*SOV60A	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A
E	Z-60B	CMS from dry-well	56	Yes	Air	3/4	6.2-70 Sh. 32	Inside Outside	1'-2"	C C	Yes(33)	2CMS*SOV24A 2CMS*SOV24C	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A
E	Z-60C	CMS to dry-well	56	No	Air	3/4	6.2-70 Sh. 32	Inside Outside	0'-3"	C C	No(31)	2CMS*SOV63A 2CMS*SOV62A	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A
E	Z-60D	CMS to dry-well	56	Yes	Air	3/4	6.2-70 Sh. 32	Inside Outside	0'-4"	C C	Yes(33)	2CMS*SOV33A 2CMS*SOV32A	- -	Globe Globe	SOV SOV	Elec. Elec.	Elec. N/A
E	Z-60E	CMS from dry-well	56	No	Air	3/4	6.2-70 Sh. 32	Inside Outside	0'-7"	C C	No(31)	2CMS*SOV61B 2CMS*SOV60B	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A
E	Z-60F	CMS from dry-well	56	Yes	Air	3/4	6.2-70 Sh. 32	Inside Outside	0'-7"	C C	Yes(33)	2CMS*SOV24B 2CMS*SOV24D	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A
E	Z-60G	CMS to drywell	56	No	Air	3/4	6.2-70 Sh. 32	Inside Outside	0'-7"	C C	No(31)	2CMS*SOV63B 2CMS*SOV62B	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A
E	Z-60H	CMS to drywell	56	Yes	Air	3/4	6.2-70 Sh. 32	Inside Outside	1'-0"	C C	Yes(33)	2CMS*SOV33B 2CMS*SOV32B	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A
	Z-61A	Capped spare				3/4				A							
E	Z-61B	CMS from wet-well	56	Yes	Air	3/4	6.2-70 Sh. 32	Inside Outside	15'-0"	C C	No(31)	2CMS*SOV26A 2CMS*SOV26C	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A
E	Z-61C	CMS to wetwell	56	Yes	Air	3/4	6.2-70 Sh. 32	Inside Outside	18'-3"	C C	No(31)	2CMS*SOV34A 2CMS*SOV35A	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A
	Z-61D	Capped spare				3/4				A							
E	Z-61E	CMS from wet-well	56	Yes	Air	3/4	6.2-70 Sh. 32	Inside Outside	0'-4"	C C	No(31)	2CMS*SOV26B 2CMS*SOV26D	- -	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A

AR nge- nt re(1)	Location of valve Inside/ Outside Primary Contain- ment	Length of Pipe - Con- tainment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Valve(9) Number SWEC	Number GE	Type	Oper- ator	Actuator Mode Primary	Actuator Mode Secondary	Position Normal (3)	Position Shutdown	Position Post- Accident	Position Power Failure(10)	Isola- tion Signal (4)	Closure Time (5,6)	Power Source (7)	Notes
70	Inside		C	Yes	2CPS*SOV121	-	Globe	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,Y, RM	N/A	Div II	21
29	Outside	14'-6"	C		2CPS*SOV119	-	Globe	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,Y, RM	N/A	Div I	
70	Inside		C	No(31)	2CMS*SOV61A	-	Globe	SOV	Elec.	N/A	Open	Closed	Closed	Closed	B,F,RM	N/A	Div II	
32	Outside	1'-2"	C		2CMS*SOV60A	-	Globe	SOV	Elec.	N/A	Open	Closed	Open	Closed	B,F,RM	N/A	Div I	
70	Inside		C	Yes(33)	2CMS*SOV24A	-	Globe	SOV	Elec.	N/A	Open	Closed	Open	Closed	B,F,RM	N/A	Div I	
32	Outside	1'-2"	C		2CMS*SOV24C	-	Globe	SOV	Elec.	N/A	Open	Closed	Open	Closed	B,F,RM	N/A	Div I	
70	Inside		C	No(31)	2CMS*SOV63A	-	Globe	SOV	Elec.	N/A	Open	Closed	Closed	Closed	B,F,RM	N/A	Div II	
32	Outside	0'-3"	C		2CMS*SOV62A	-	Globe	SOV	Elec.	N/A	Open	Closed	Closed	Closed	B,F,RM	N/A	Div I	
70	Inside		C	Yes(33)	2CMS*SOV33A	-	Globe	SOV	Elec.	Elec.	Open	Closed	Open	Closed	B,F,RM	N/A	Div I	
32	Outside	0'-4"	C		2CMS*SOV32A	-	Globe	SOV	Elec.	N/A	Open	Closed	Open	Closed	B,F,RM	N/A	Div I	
70	Inside		C	No(31)	2CMS*SOV61B	-	Globe	SOV	Elec.	N/A	Open	Closed	Closed	Closed	B,F,RM	N/A	Div II	
32	Outside	0'-7"	C		2CMS*SOV60B	-	Globe	SOV	Elec.	N/A	Open	Closed	Closed	Closed	B,F,RM	N/A	Div I	
70	Inside		C	Yes(33)	2CMS*SOV24B	-	Globe	SOV	Elec.	N/A	Open	Closed	Open	Closed	B,F,RM	N/A	Div II	
32	Outside	0'-7"	C		2CMS*SOV24D	-	Globe	SOV	Elec.	N/A	Open	Closed	Open	Closed	B,F,RM	N/A	Div II	
70	Inside		C	No(31)	2CMS*SOV63B	-	Globe	SOV	Elec.	N/A	Open	Closed	Closed	Closed	B,F,RM	N/A	Div II	
32	Outside	0'-7"	C		2CMS*SOV62B	-	Globe	SOV	Elec.	N/A	Open	Closed	Closed	Closed	B,F,RM	N/A	Div I	
70	Inside		C	Yes(33)	2CMS*SOV33B	-	Globe	SOV	Elec.	N/A	Open	Closed	Open	Closed	B,F,RM	N/A	Div II	
32	Outside	1'-0"	C		2CMS*SOV32B	-	Globe	SOV	Elec.	N/A	Open	Closed	Open	Closed	B,F,RM	N/A	Div II	
			A															
70	Inside		C	No(31)	2CMS*SOV26A	-	Globe	SOV	Elec.	N/A	Open	Closed	Open	Closed	B,F,RM	N/A	Div I	
32	Outside	15'-0"	C		2CMS*SOV26C	-	Globe	SOV	Elec.	N/A	Open	Closed	Open	Closed	B,F,RM	N/A	Div I	
70	Inside		C	No(31)	2CMS*SOV34A	-	Globe	SOV	Elec.	N/A	Open	Closed	Open	Closed	B,F,RM	N/A	Div I	
32	Outside	18'-3"	C		2CMS*SOV35A	-	Globe	SOV	Elec.	N/A	Open	Closed	Open	Closed	B,F,RM	N/A	Div I	
			A															
70	Inside		C	No(31)	2CMS*SOV26B	-	Globe	SOV	Elec.	N/A	Open	Closed	Open	Closed	B,F,RM	N/A	Div II	
32	Outside	0'-4"	C		2CMS*SOV26D	-	Globe	SOV	Elec.	N/A	Open	Closed	Open	Closed	B,F,RM	N/A	Div II	

Table A.2.9 (Continued)

	Pene-tration No.	System Designation	GDC or Reg. Guide	ESF System	Fluid	Size (in)	FSAR Arrange-ment Figure(1)	Location of valve Inside/ Outside Primary Contain-ment	Length of Pipe - Con-tainment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Number SWEC	Number GE	Type	Oper-ator	Actuator Mode Primary	Actuator Mode Secondary	Normal (3)	S
E	Z-61F	CMS to wetwell	56	Yes	Air	3/4	6.2-70 Sh. 32	Inside		C	No(31)	2CMS*SOV34B	-	Globe	SOV	Elec.	N/A	Open	(
								Outside	0'-4"	C		2CMS*SOV35B	-	Globe	SOV	Elec.	N/A	Open	(
	Z-67	Spare				10				A									
	Z-68	Capped spare				10				A									
	Z-69	Spare				6													
	Z-70	Capped spare				6				A									
	Z-71	Spare				3				A									
	Z-72	Capped spare				14				A									
E	Z-73	RHS relief valve dis-charge to suppression pool	56	No	Water	6	6.2-70 Sh. 33	Outside	48'-6"	A	No(29)	2RHS*RV108 2RHS*RV20C	E12-F036 E12-F025C	FV	N/A	N/A	N/A	N/A	N/
	Z-74	Capped spare				6				A									
	Z-75	Capped spare				3				A									
	Z-76	Capped spare				3				A									
	Z-77	Capped spare				1 1/2				A									
	Z-78	Capped spare				1 1/2				A									
	Z-79	Capped spare				1 1/2				A									
E	Z-80	Spent fuel pool cooling	56	No	Water	1 1/2	6.2-70 Sh. 40	Outside	1'-6"	C	No(31)	2SFC*V203	-	Globe	Manual	Manual	N/A	Closed	Cl
								Inside		C		2SFC*V204	-	Globe	Manual	Manual	N/A	Closed	Cl
	Z-81	Capped spare				1 1/2				A									
	Z-82	Capped spare				1				A									

Type Test (1)	Potential Bypass Leakage Path	Number SWEC	Number GE	Valve(9) Type	Oper-ator	Actuator Mode Primary	Actuator Mode Secondary	Position Normal (3)	Position Shutdown	Position Post-Accident	Position Power Failure	Isola-tion Signal (4)	Closure Time (5,6)	Power Source (7)	Notes	
																17
C	No(31)	2CMS*SOV34B	-	Globe	SOV	Elec.	N/A	Open	Closed	Open	Closed	B,F,RM	N/A	Div II		
C		2CMS*SOV35B	-	Globe	SOV	Elec.	N/A	Open	Closed	Open	Closed	B,F,RM	N/A	Div II		
A																
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A	No(29)	2RHS*RV108	E12-F036	RV	N/A	N/A	N/A	N/A	N/A	N/A	N/A	None	N/A	N/A		
		2RHS*RV20C	E12-F025C													
A																
A																
A																
A																
A																
A																
C	No(31)	2SFC*V203	-	Globe	Manual	Manual	N/A	Closed	Closed	Closed	N/A	LC	N/A	N/A		17
C		2SFC*V204	-	Globe	Manual	Manual	N/A	Closed	Closed	Closed	N/A	LC	N/A	N/A		
A																
A																

Table A.2.9 (Continued)

	Penetration No.	System Designation	GDC or Reg. Guide	ESF System	Fluid	Size (in)	FSAR Arrangement Figure(1)	Location of valve Inside/Outside Primary Containment	Length of Pipe - Containment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Number SWEC	Number GE	Typ
	Z-83	Capped spare				1				A				
	Z-85	Capped spare				1				A				
	Z-86	Capped spare				1				A				
	Z-87	Capped spare				1				A				
E	Z-88A	RHS safety valve discharge to suppression pool	56	Yes	Steam	12	6.2-70 Sh. 34	Outside	116'2"	A	No(29)			
E	Z-88B	RHR safety valve discharge to suppression pool	56	Yes	Steam	12	6.2-70 Sh. 34	Outside	106'-3"	A	No(29)			
E	Z-89A	LMS from drywell	56	No	Air	3/4	6.2-70 Sh. 35	Inside Outside	 0'-2"	C C	No(31)	2LMS*SOV152 2LMS*SOV153	- -	Glo Glo
	Z-89B	Capped spare				3/4				A				
E	Z-89C	LMS from wetwell	56	No	Air	3/4	6.2-70 Sh. 35	Inside Outside	 0'-2"	C C	No(31)	2LMS*SOV156 2LMS*SOV157	- -	Glo Glo
	Z-89D	Capped spare				3/4				A				
E	Z-90	ICS vacuum breaker	56	Yes	Air	1 1/2	6.2-70 Sh. 36	Outside Outside	23'-10" 29'-11"	C C	No(29)	2ICS*MOV148 2ICS*MOV164	E51-F086 E51-F080	Glo Glo
E	Z-91A	Instrument air to drywell	56	No	N_2	1 1/2	6.2-70 Sh. 37	Outside Inside	1'-0"	C C	Yes(30)	2IAS*SOV167 2IAS*SOV185	- -	Glo Glo
E	Z-91B	Instrument air to drywell	56	No	N_2	1 1/2	6.2-70 Sh. 37	Outside Inside	1'-0"	C C	Yes(30)	2IAS*SOV168 2IAS*SOV180	- -	Glo Glo
	Z-91C	Capped spare				1 1/2				A				
	Z-91D	Capped spare				1 1/2				A				

Location of valve Inside/ Outside Primary Contain- ment	Length of Pipe - Con- tainment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Valve(9) Number SWEC	Number GE	Type	Oper- ator	Actuator Mode Primary	Actuator Mode Secondary	Position Normal (3)	Position Shutdown	Position Post- Accident	Position Power Failure(10)	Isola- tion Signal (4)	Closure Time (5,6)	Power Source (7)	Notes
		A															
		A															
		A															
		A															
Outside	116'2"	A	No(29)							See Note 23							
Outside	106'-3"	A	No(29)							See Note 24							
Inside		C	No(31)	2LMS*SOV152	-	Globe	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,RM	N/A	Div II	
Outside	0'-2"	C		2LMS*SOV153	-	Globe	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,RM	N/A	Div I	
		A															
Inside		C	No(31)	2LMS*SOV156	-	Globe	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,RM	N/A	Div II	
Outside	0'-2"	C		2LMS*SOV157	-	Globe	SOV	Elec.	N/A	Closed	Closed	Closed	Closed	B,F,RM	N/A	Div I	
		A															
Outside	23'-10"	C	No(29)	2ICS*MOV148	E51-F086	Globe	MOV	Elec.	Manual	Open	Closed	Open	FAI	FSH,RM	9	Div II	21
Outside	29'-11"	C		2ICS*MOV164	E51-F080	Globe	MOV	Elec.	Manual	Open	Closed	Open	FAI	F&H,RM	9	Div I	
Outside	1'-0"	C	Yes(30)	2IAS*SOV167	-	Globe	SOV	Elec.	N/A	Open	Open	Closed	Closed	B,F,RM	N/A	Div I	
Inside		C		2IAS*SOV185	-	Globe	SOV	Elec.	N/A	Open	Open	Closed	Closed	B,F,RM	N/A	Div II	
Outside	1'-0"	C	Yes(30)	2IAS*SOV168	-	Globe	SOV	Elec.	N/A	Open	Open	Closed	Closed	B,F,RM	N/A	Div I	
Inside		C		2IAS*SOV180	-	Globe	SOV	Elec.	N/A	Open	Open	Closed	Closed	B,F,RM	N/A	Div II	
		A															
		A															

Table A.2.9 (Continued)

	Pene-tration No.	System Designation	GDC or Reg. Guide	ESF System	Fluid	Size (in)	FSAR Arrange-ment Figure(1)	Location of valve Inside/ Outside Primary Contain-ment	Length of Pipe - Con-tainment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Valve(Number SWEC	Number GE	Type	Oper-ator	Actuator Mode Primary	Actuator Mode Secondary	Po Normal (3)	Po Shutdo
	Z-92	Spare				1				A									
	Z-96	Spare								A									
E	Z-98A	RHR relief valve discharge to suppression pool	56	Yes	Water	3	6.2-70 Sh. 38	Outside	207'-6"	A	No(29)	2CSL*RV123 2CSL*RV105 2RHS*RV61A 2RHS*RV110 2RHS*RV139 2RHS*RV20A	E21-F031 E21-F018 E12-F088A E12-F005 E12-F030 E12-F025A	Relief Valves	N/A	N/A	N/A	N/A	N/A
E	Z-98B	RHR relief valve discharge to suppression pool	56	Yes	Water	3	6.2-70 Sh. 38	Outside	89'-8"	A	No(29)	2CSH*RV114 2CSH*RV113 2RHS*RV61B 2RHS*RV61C 2RHS*RV20B	E22-F035 E22-F014 E12-F088B E12-F088C E12-F025B	Relief Valves	N/A	N/A	N/A	N/A	N/A
E	Z-99A	Hydraulic unit from recirc flow control valve HYV 17A (drain line)	56	No	Hy-draulic	3/4	6.2-70 Sh. 39	Outside Inside	0'-0" 0'-0"	N/A	No(31)	2RCS*SOV68A 2RCS*SOV82A	-	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Close Close
E	Z-99B	Hydraulic unit to recirc flow control valve HYV 17A (open line)	56	No	Hy-draulic	1	6.2-70 Sh. 39	Outside Inside	0'-0" 0'-0"	N/A	No(31)	2RCS*SOV67A 2RCS*SOV81A	-	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Close Close
E	Z-99C	Hydraulic unit to recirc flow control valve HYV 17A (pilot line)	56	No	Hy-draulic	1	6.2-70 Sh. 39	Outside Inside	0'-0" 0'-0"	N/A	No(31)	2RCS*SOV66A 2RCS*SOV80A	-	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Close Close

Valve(9)														
Number				Actuator Mode		Position				Isolation Signal (4)	Closure Time (5,6)	Power Source (7)	Notes	
SWEC	GE	Type	Operator	Primary	Secondary	Normal (3)	Shutdown	Post-Accident	Power Failure					17
2CSL*RV123	E21-F031	Relief Valves	N/A	N/A	N/A	N/A	N/A	N/A	N/A	None	N/A	N/A		
2CSL*RV105	E21-F018													
2RHS*RV61A	E12-F088A													
2RHS*RV110	E12-F005													
2RHS*RV139	E12-F030													
2RHS*RV20A	E12-F025A													
2CSH*RV114	E22-F035	Relief Valves	N/A	N/A	N/A	N/A	N/A	N/A	N/A	None	N/A	N/A		
2CSH*RV113	E22-F014													
2RHS*RV61B	E12-F088B													
2RHS*RV61C	E12-F088C													
2RHS*RV20B	E12-F025B													
2RCS*SOV68A	-	Globe	SOV	Elec.	N/A	Open	Closed	Closed	Closed	B,F,RM	N/A	Div I	26	
2RCS*SOV82A		Globe	SOV	Elec.	N/A	Open	Closed	Closed	Closed	B,F,RM	N/A	Div II		
2RCS*SOV67A	-	Globe	SOV	Elec.	N/A	Open	Closed	Closed	Closed	B,F,RM	N/A	Div I	26	
2RCS*SOV81A		Globe	SOV	Elec.	N/A	Open	Closed	Closed	Closed	B,F,RM	N/A	Div II		
2RCS*SOV66A	-	Globe	SOV	Elec.	N/A	Open	Closed	Closed	Closed	B,F,RM	N/A	Div I	26	
2RCS*SOV80A		Globe	SOV	Elec.	N/A	Open	Closed	Closed	Closed	B,F,RM	N/A	Div II		

Table A.2.9 (Continued)

	Penetration No.	System Designation	GDC or Reg. Guide	ESF System	Fluid	Size (in)	FSAR Arrangement Figure(1)	Location of valve Inside/Outside Primary Containment	Length of Pipe - Containment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Number SWEC	Number GE	Type
E	Z-99D	Hydraulic unit to recirc flow control valve HYV 17A (closed line)	56	No	Hy-draulic	1	6.2-70 Sh. 39	Outside Inside	0'-0" 0'-0"	N/A	No(31)	2RCS*SOV65A 2RCS*SOV79A	-	Globe Globe
E	Z-100A	Hydraulic unit from recirc flow control valve HYV 17B (drain line)	56	No	Hy-draulic	3/4	6.2-70 Sh. 39	Outside Inside	0'-0" 0'-0"	N/A	No(31)	2RCS*SOV68B 2RCS*SOV82B	-	Globe Globe
E	Z-100B	Hydraulic unit to recirc flow control valve HYV 17B (open line)	56	No	Hy-draulic	1	6.2-70 Sh. 39	Outside Inside	0'-0" 0'-0"	N/A	No(31)	2RCS*SOV67B 2RCS*SOV818	-	Globe Globe
E	Z-100C	Hydraulic unit to recirc flow control valve HYV 17B (pilot) line)	56	No	Hy-draulic	1	6.2-70 Sh. 39	Outside Inside	0'-0" 0'-0"	N/A	No(31)	2RCS*SOV66B 2RCS*SOV80B	-	Globe Globe
E	Z-100D	Hydraulic unit to recirc flow control valve HYV 17B (closed line)	56	No	Hy-draulic	1	6.2-70 Sh. 39	Outside Inside	0'-0" 0'-0"	N/A	No(31)	2RCS*SOV65B 2RCS*SOV79B	-	Globe Globe
		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(31)	EF check valves	-	EFV
		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(31)	EFV	-	EFV

SAR Arrange-ment Figure(1)	Location of valve Inside/ Outside Primary Contain-ment	Length of Pipe - Con-tainment to Outside Isolation Valve	Type Test (1)	Potential Bypass Leakage Path	Valve(9) Number SWEC	Number GE	Type	Oper-ator	Actuator Mode Primary	Actuator Mode Secondary	Position Normal (3)	Position Shutdown	Position Post-Accident	Position Power Failure	Isola-tion Signal (4)	Closure Time (5,6)	Power Source (7)	Notes	
																			17
-70 39	Outside Inside	0'-0" 0'-0"	N/A	No(31)	2RCS*SOV65A 2RCS*SOV79A	-	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Closed Closed	Closed Closed	B,F,RM B,F,RM	N/A N/A	Div I Div II	26	17
:-70 39	Outside Inside	0'-0" 0'-0"	N/A	No(31)	2RCS*SOV68B 2RCS*SOV82B	-	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Closed Closed	Closed Closed	B,F,RM B,F,RM	N/A N/A	Div I Div II	26	17
:-70 . 39	Outside Inside	0'-0" 0'-0"	N/A	No(31)	2RCS*SOV67B 2RCS*SOV818	-	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Closed Closed	Closed Closed	B,F,RM B,F,RM	N/A N/A	Div I Div II	26	17
:-70 . 39	Outside Inside	0'-0" 0'-0"	N/A	No(31)	2RCS*SOV66B 2RCS*SOV80B	-	Globe Globe	SCV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Closed Closed	Closed Closed	B,F,RM B,F,RM	N/A N/A	Div I Div II	26	17
2-70 . 39	Outside Inside	0'-0" 0'-0"	N/A	No(31)	2RCS*SOV55B 2RCS*SOV79B	-	Globe Globe	SOV SOV	Elec. Elec.	N/A N/A	Open Open	Closed Closed	Closed Closed	Closed Closed	B,F,RM B,F,RM	N/A N/A	Div I Div II	26	17
2-70 . 41	Outside	<10'-0"	A	No(31)	EF check valves	-	EFV	N/A	Auto	N/A	Open	Open	Open	Open	Excess flow	N/A	N/A	27	17
2-70 . 41	Outside	<10'-0"	A	No(31)	EFV	-	EFV	N/A	Auto	N/A	Open	Open	Open	Open	Excess flow	N/A	N/A	27	17

A.3 Interfacing Lines at Quad Cities

The interfacing lines identified for Quad Cities were 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.3.1-A.3.4. 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 was included in the study. A letter code means that the line was 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.3.1). 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. 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). High space temperature alarms are provided along the shutdown cooling line to alert the operator to a break or leak in this line.

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 system. 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.3.1).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 as well.

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.3.1). 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 the feedwater 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.3.2). 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).

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.3.3). 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 would be 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

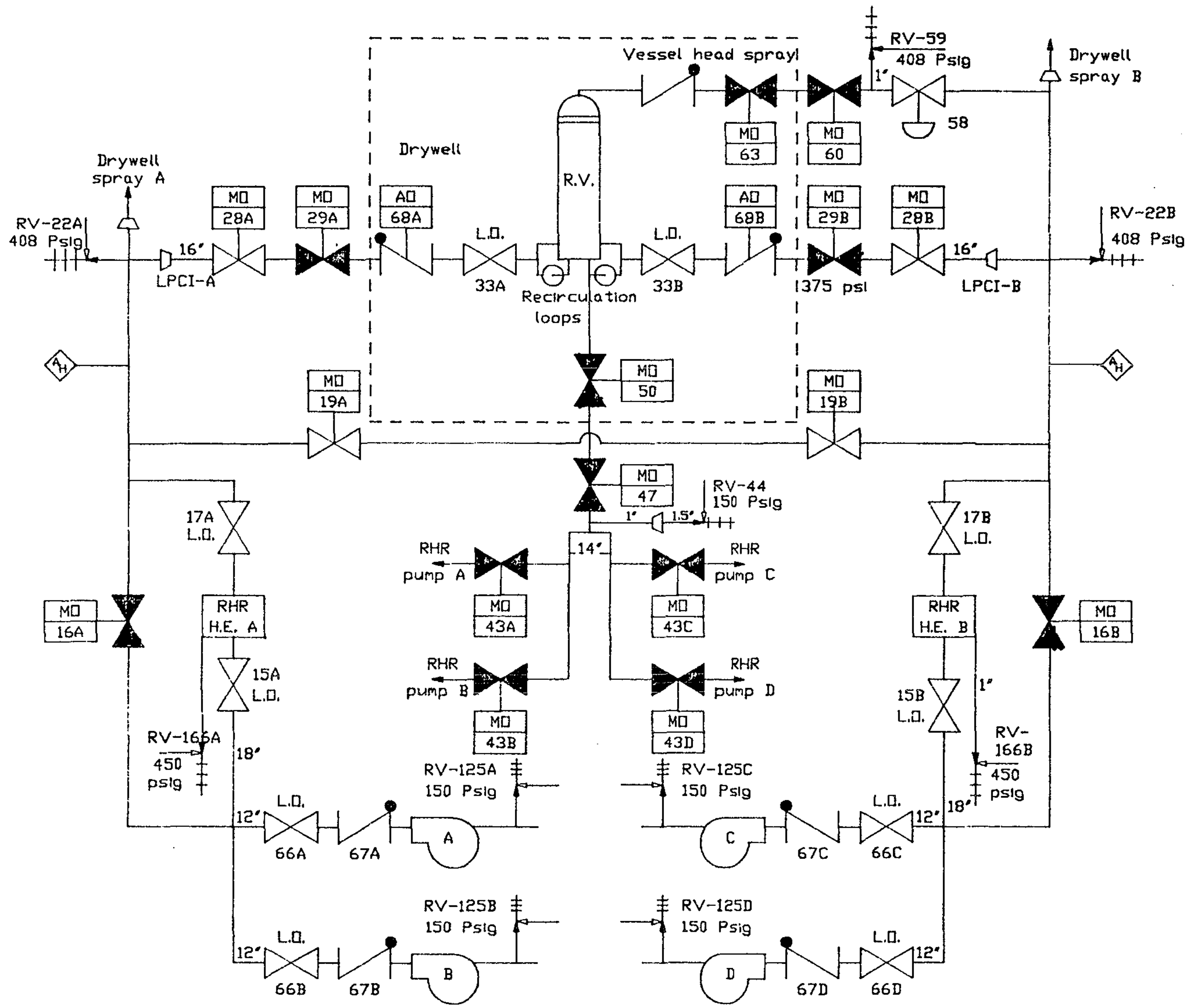
The HPCI injection line feeds into the feedwater line upstream of the feedwater line's containment isolation valves. Therefore, in order to have an interfacing system LOCA, the two normally open (during operation) feedwater

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.3.4). 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 when the HPCI turbine is signaled to trip (see Table A.3.7). Automatic tripping of the HPCI turbine occurs when either of two high turbine exhaust pressure switches is 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 Quad Cities 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' (Quad Cities Unit 1 or Unit 2) HPCI injection line upstream of the HPCI air-operated check valve (see Figure A.3.4). 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 associated piping between the low pressure pump suction and the reactor pressure of either unit. Therefore, this line has not been analyzed further with respect to interfacing system LOCA.

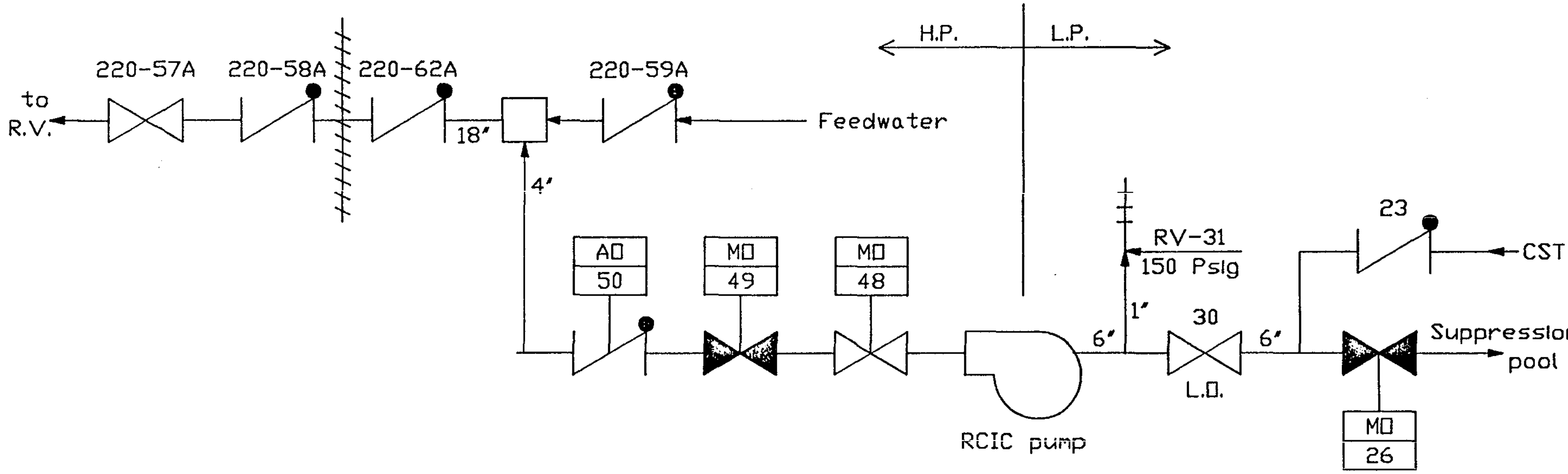
A.3.6.2 Indication of Overpressurization or Interfacing LOCA

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.



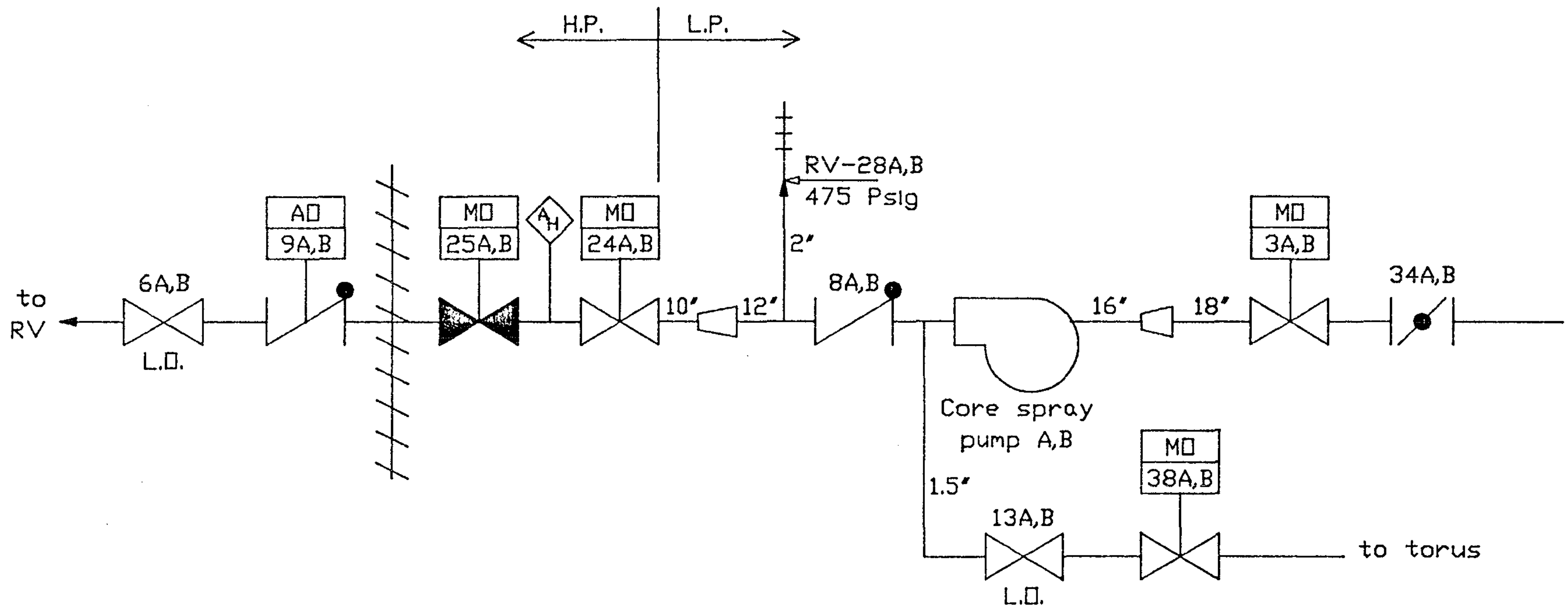
Note: All equipment have the following prefix 1001-.

Figure A.3.1 Residual heat removal system.
(Quad Cities)



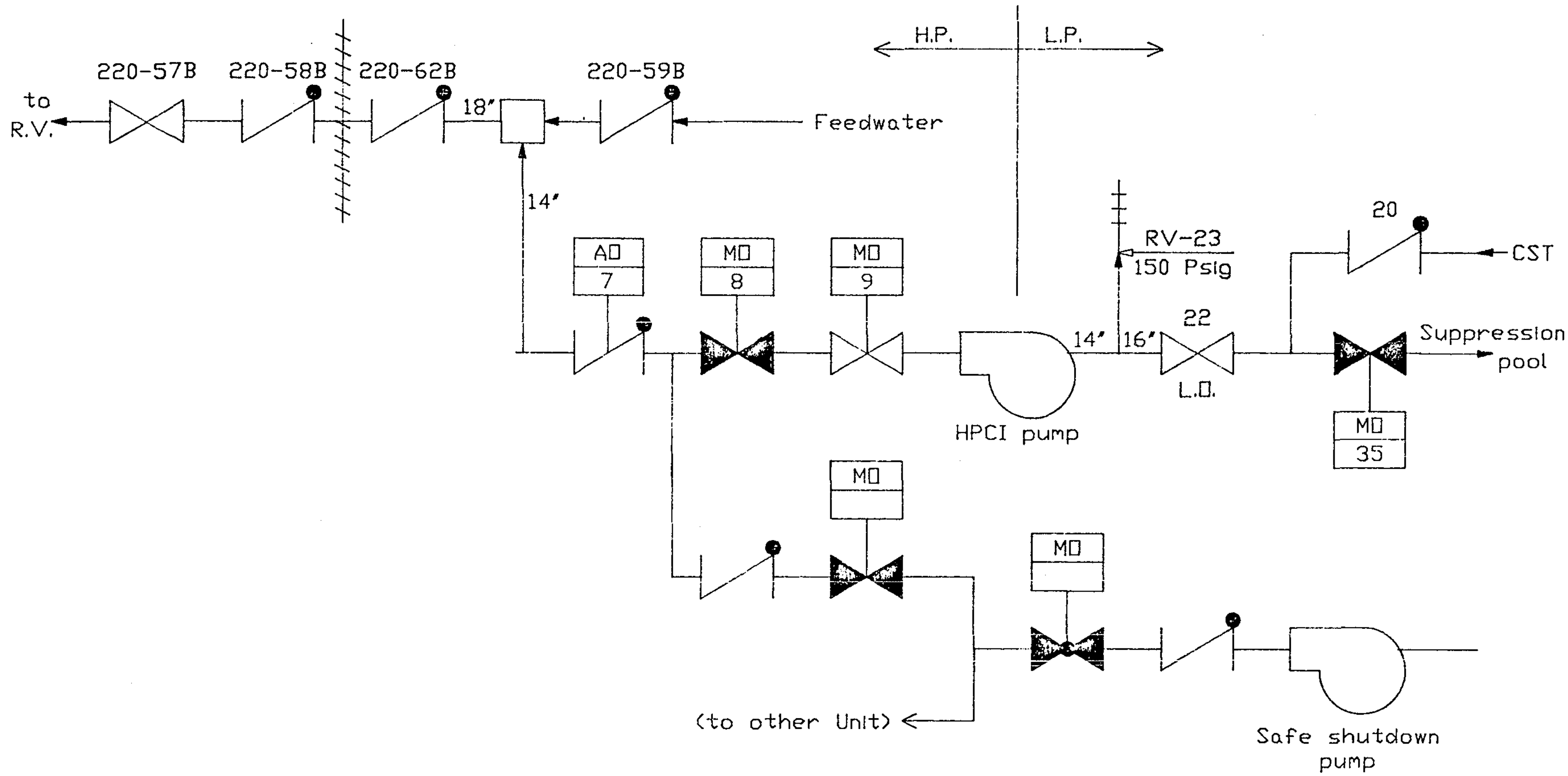
Note: All equipment has the following prefix, 1301, if other prefix is not shown.

Figure A.3.2 RCIC system.
(Quad Cities)



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

Figure A.3.3 LPCS system.
(Quad Cities)



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

Figure A.3.4 HPCI system.
(Quad Cities)

Table A.3.1
Shutdown Cooling Supply (RHR) (Quad Cities)

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) (Quad Cities)

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) (Quad Cities)

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 &	RV-22A,B	RV-59	RV-166A&B1" @ 408 psig
	1" @ 408 psig 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* (Quad Cities)

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 (Quad Cities)

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 (Quad Cities)

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* (Quad Cities)

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 (Quad Cities)

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[1] Penetration Number	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 movement & 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.
Ⓑ	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.
Ⓖ	Valve opens on signal "G". Signal "L" overrides signal Ⓖ.
H	Line break in recirculation loop - close corresponding RHR-LPCI loop valves and open valves in opposite loop.
Ⓙ	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 flow 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 flow or low steam line pressure).
Ⓜ	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.
Ⓥ	Valve opens on coincident signals "G" and "T". Signal "H" overrides signal Ⓥ.
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 75-24)

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 stem 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 Specs.

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 letdown. Reactor coolant pumps A and C were operated 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.

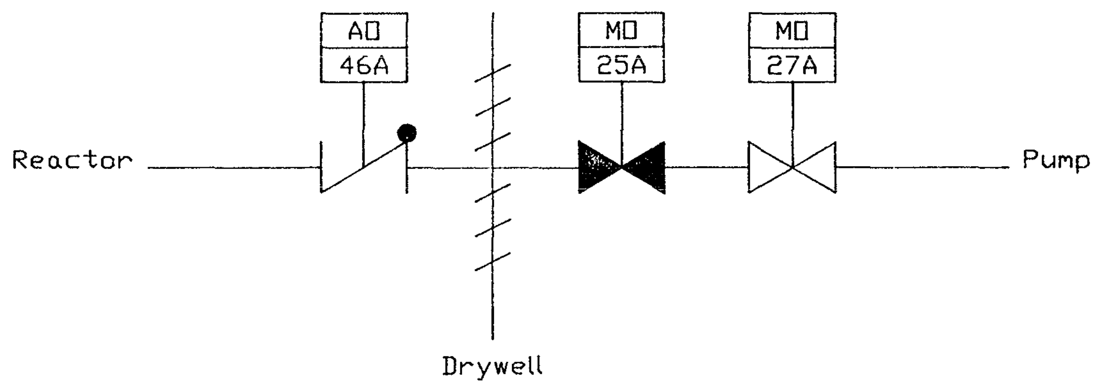


Figure B.1 Valve arrangement for LPCI injection line at Vermont Yankee on 12/12/75.

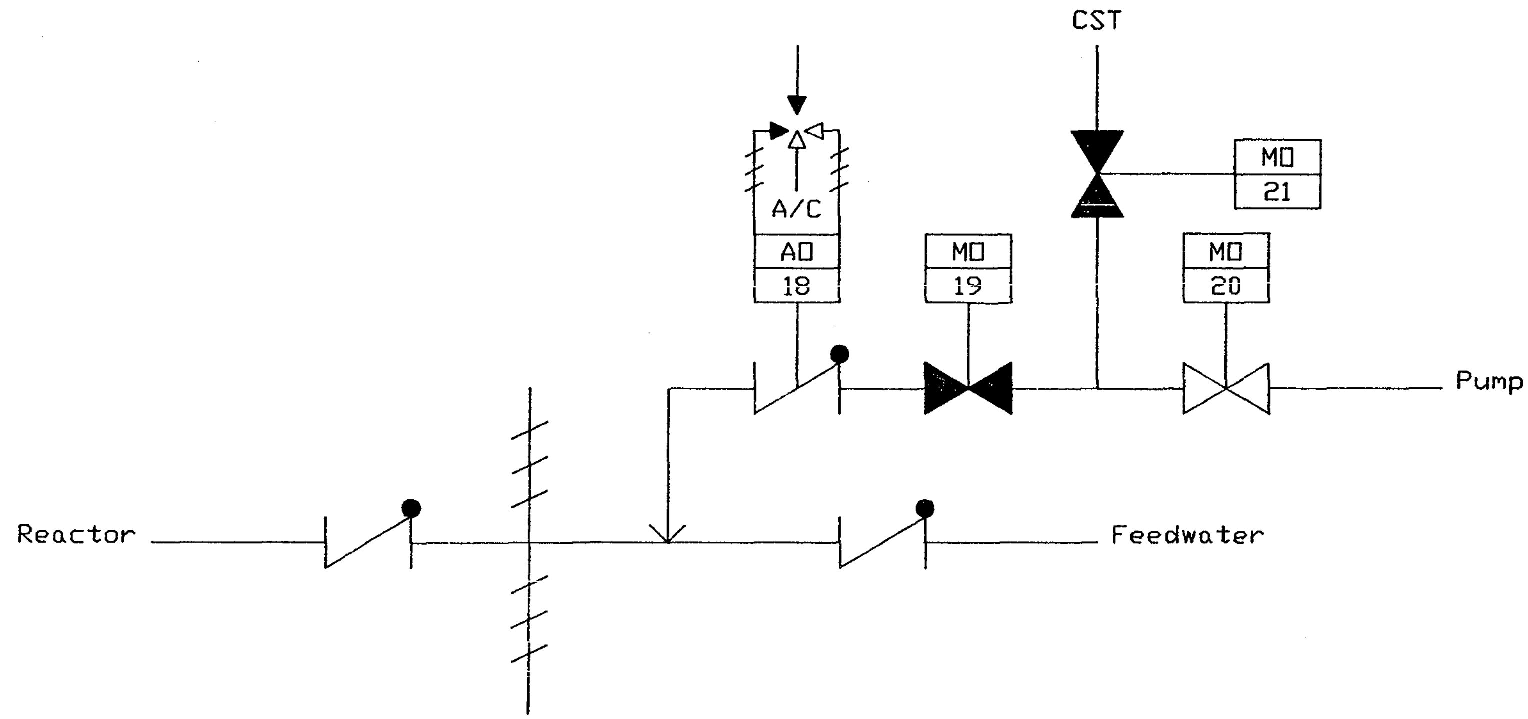


Figure B.2 Valve arrangement for HPCI injection line at Cooper on 1/21/77.

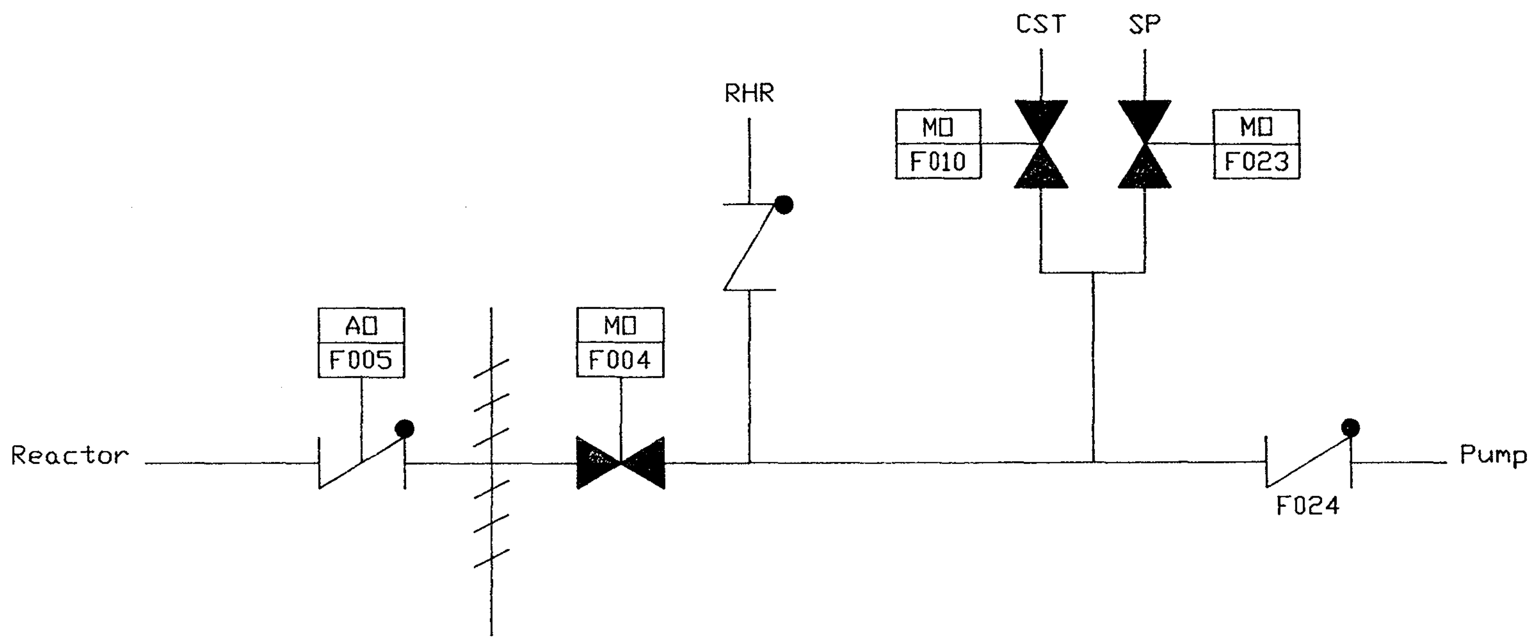


Figure B.3 Valve arrangement for HPCS injection line at LaSalle-1 on 10/5/82 and 6/17/83.

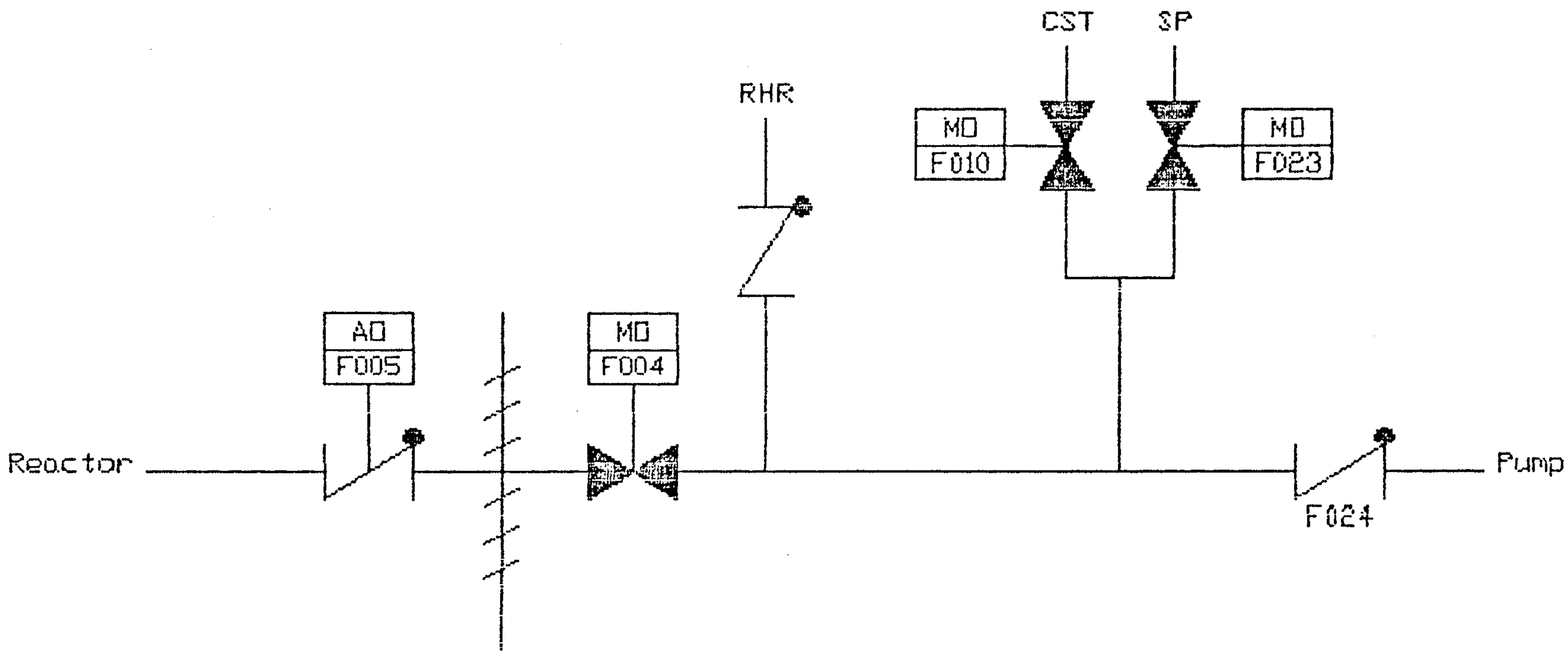


Figure B.4 Valve arrangement for HPCS injection line at LaSalle-1 on October 5, 1982 and June 17, 1983.

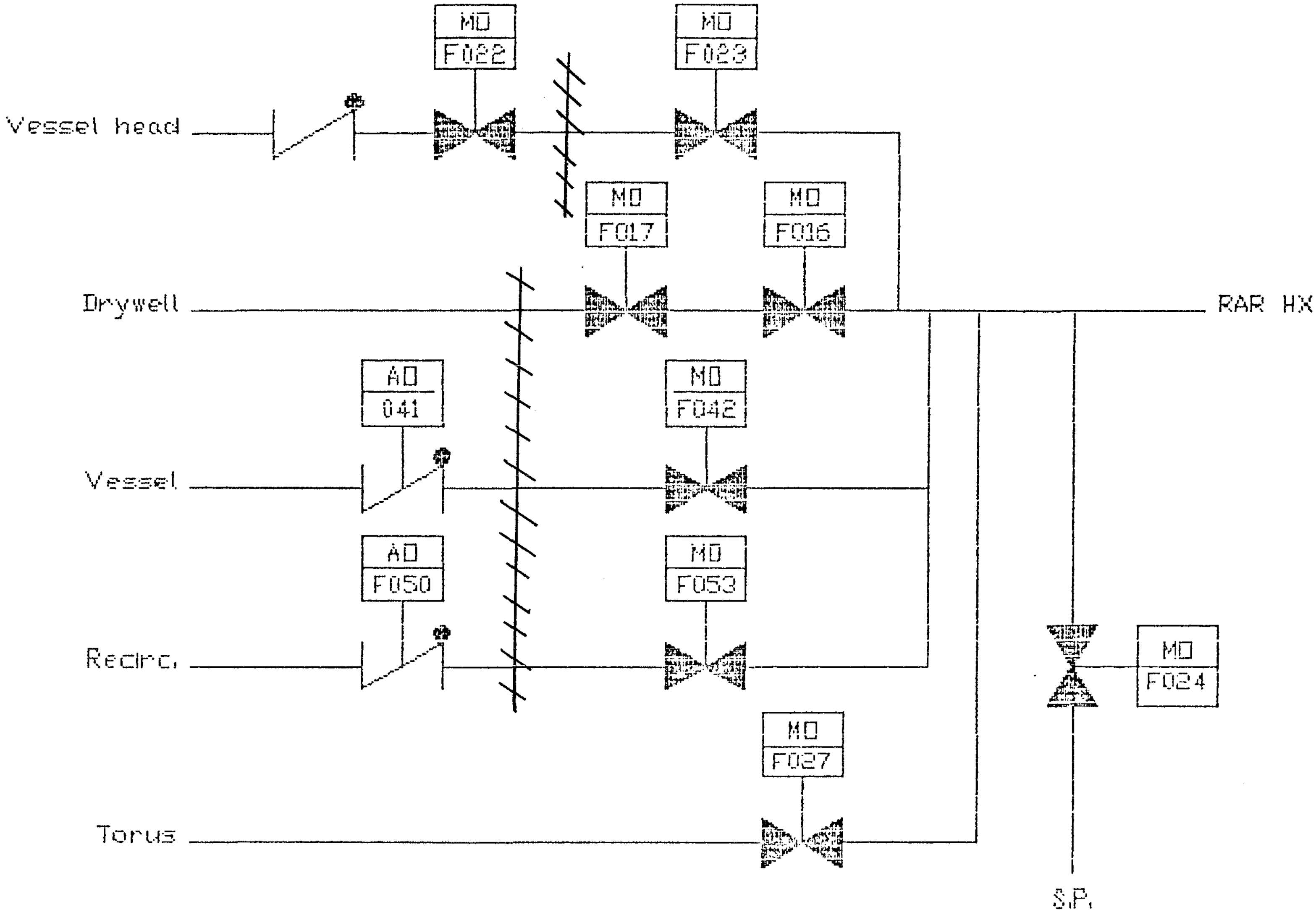


Figure B.5 Valve arrangement for LPCI injection line at LaSalle-1 on September 14, 1983.

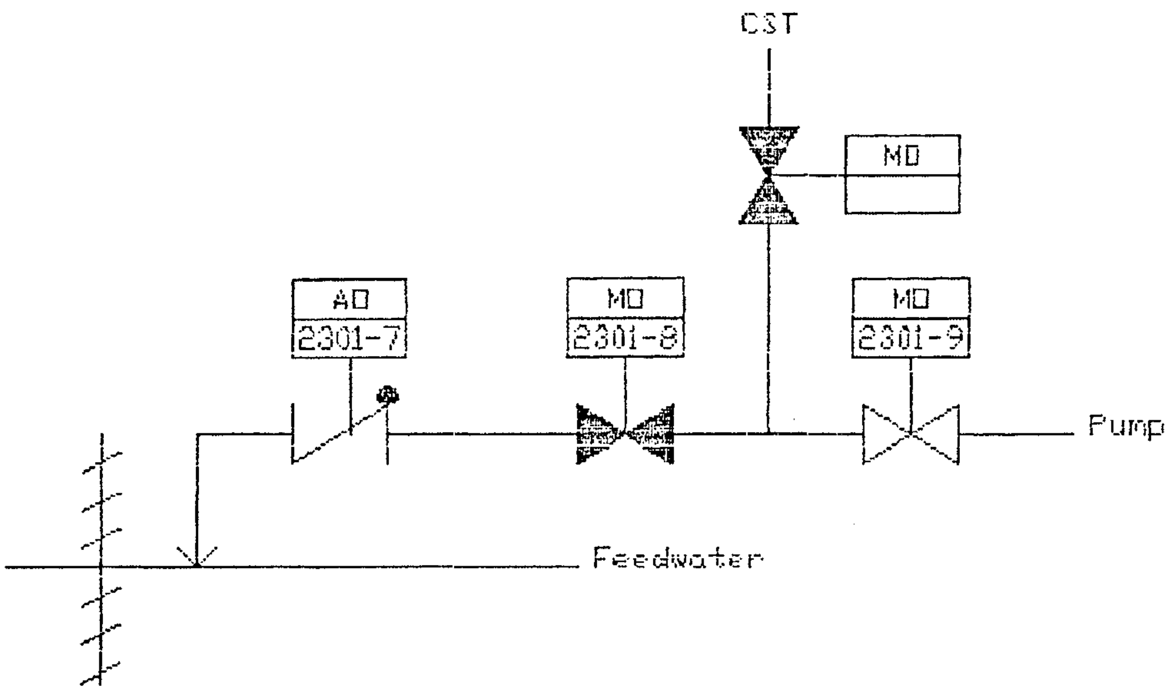


Figure B.6 Valve arrangement for HPCI injection line at Pilgrim on September 29, 1983.

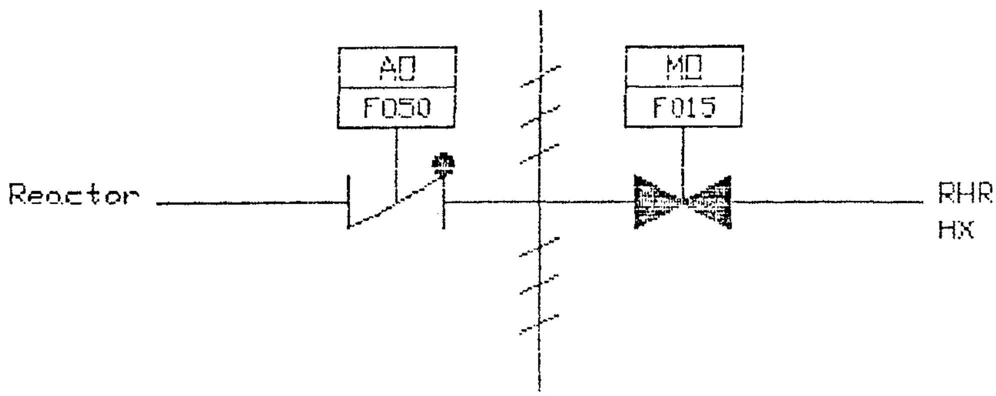


Figure B.7 Valve arrangement for LPCI injection line at Hatch-2 on October 28, 1983.

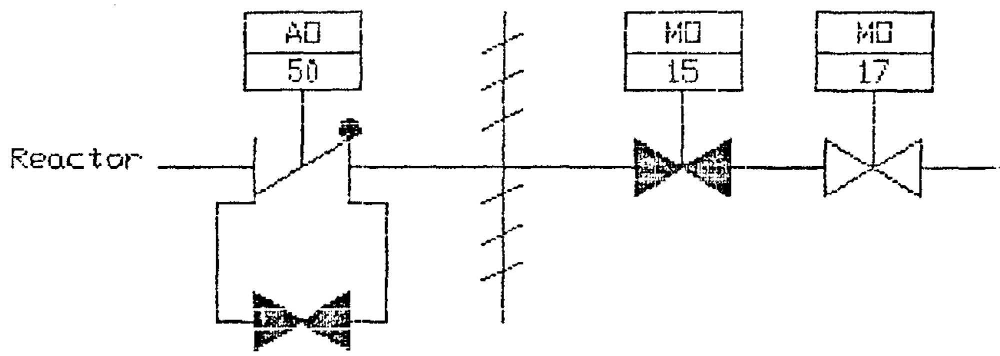


Figure B.8 Valve arrangement for LPCI injection line at Susquehanna on May 28, 1984.

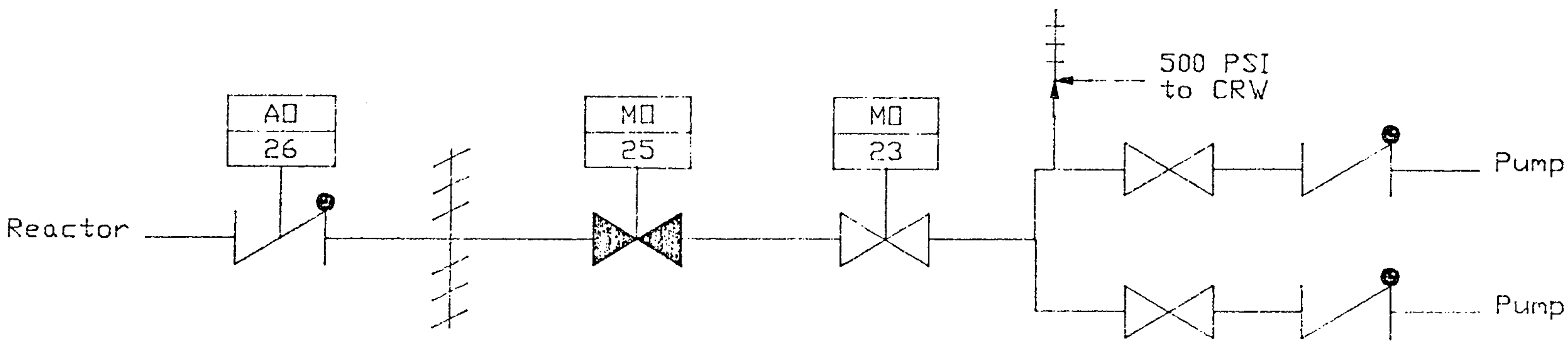


Figure B.9 Valve arrangement for core spray injection line at Browns Ferry-1 on August 14, 1984.

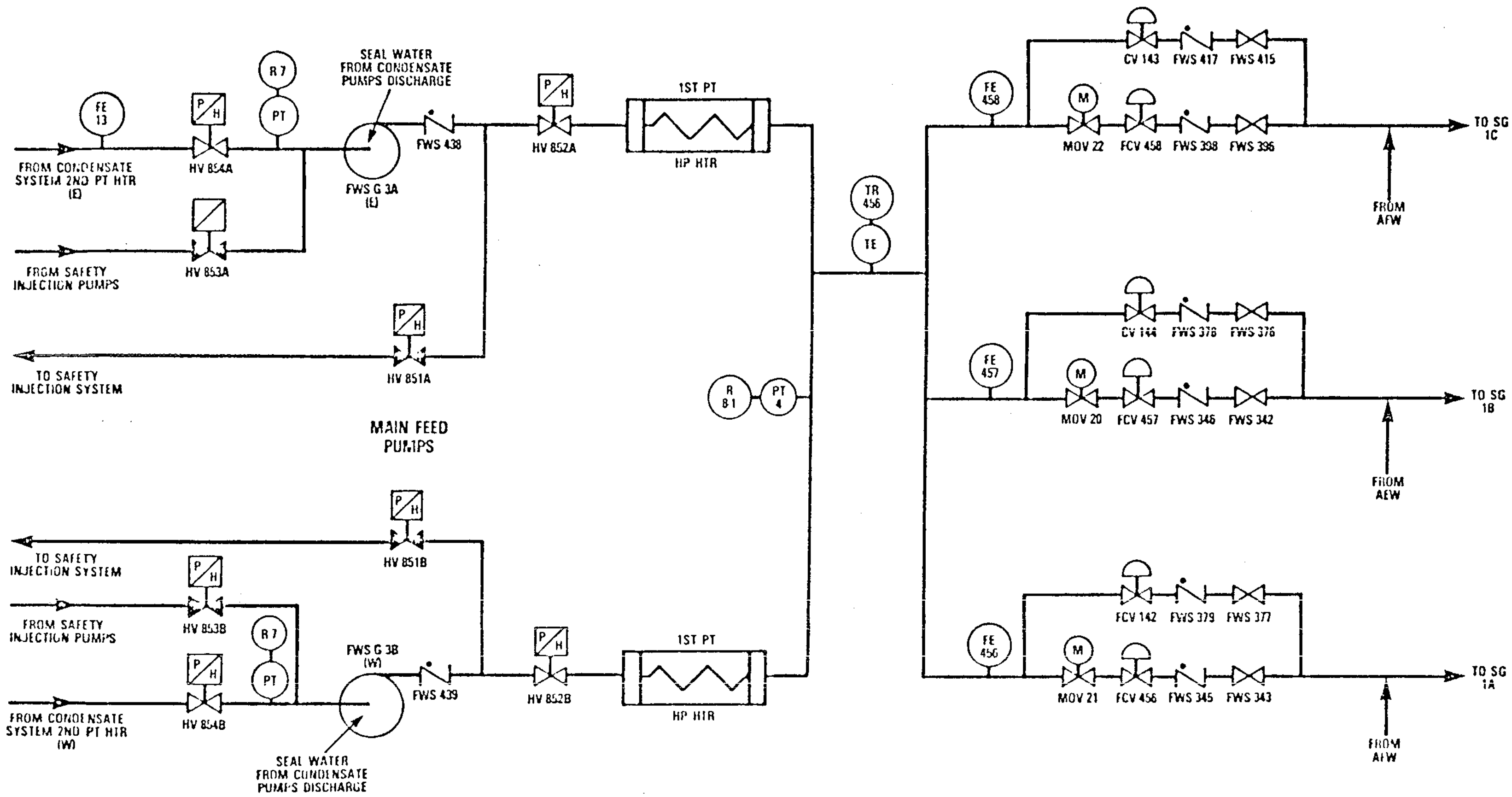


Figure B.10 Main feed system for San Onofre.

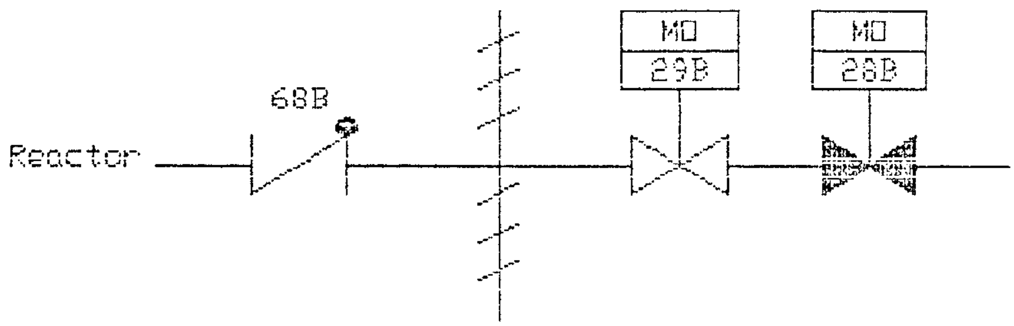


Figure B.11 Valve arrangement for LPCI injection line at Pilgrim on February 13, 1986.

APPENDIX C: Assessment of Core Damage Frequency Due to Intersystem LOCA in Representative BWR Plants

This appendix 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 the ECCS injection lines was 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 C.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 could 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 was judged to be credible, then the operating event experience was used to estimate the frequency of failure. When any of the operating event experience was judged not to apply to a given interfacing line, the failure data from Table 4.1 was used to assess the frequencies of different combinations of pressure isolation valve (PIV) failure modes that would lead to overpressurization.

Given that a segment of low pressure piping would become overpressurized, then the possibility that a rupture would occur was considered. Figure C.1 illustrates the event tree used to determine the conditional probability of various sized LOCAs given that the low pressure piping was overpressurized. The probabilities in the figure apply to the LPCI line at Peach Bottom with the PIVs failed in a Browns-Ferry-like scenario. Given that low pressure piping becomes overpressurized, the probability that a rupture would occur is assessed in Appendix E. Basically, a probability distribution representing the strength of the ASTM A106 Grade B carbon Steel was assessed. The hoop stress at 1050 psi in a pipe section of a given diameter and thickness is then used to determine the rupture probability. Tables C.2 to C.4 list, for all interfacing lines of the three reference plants, the diameter and thickness of the pipe sections that would be overpressurized if the PIVs in the interfacing line failed open. Also listed in the tables are the probabilities of pipe rupture assessed in Appendix E. 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. Given that the BWR Owners' Group work was focused on pipe welds, it is believed to provide a lower bound for the rupture probability, i.e., if the rupture probability assess in Appendix E was lower than 3×10^{-5}, then 3×10^{-5} was used in the quantification of the core damage frequencies. Appendix F provides the core damage frequency results of sensitivity calculations using three values for the probability of rupture ; 10^{-1}, 10^{-3}, and 3.0×10^{-5}.

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 conservatively assumed that core damage will result due to structural failure, flooding ECCS equipment, and/or draining of the suppression pool. This results in sequence 5 in Figure C.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 the ECCS is made inoperable by the blowdown, the condensate pumps may be available to provide makeup to the reactor coolant system. In this study, no credit was given to the condensate pumps, because the operability of the condensate pumps may be affected by the blowdown, and timely operator response would be required.

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 C.1, depending on the operator's ability to isolate 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 C.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 C.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. Sequence 4 in Figure C.1 represents the case that a pipe rupture occurs as a result of the overpressurization, the check valve closes on reverse flow and the operator fails to isolate the small LOCA that is assumed to have occurred through the check valve.

Basically, the small LOCA event tree in Figure C.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 manually 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 C.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 was conservatively assumed that if the operators fail to depressurize in two hours, all ECCS would be disabled due to flooding. This results in sequence 4 or 5 and sequence 9 or 10 in Figure C.3. A probability of 5×10^{-2} was 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,

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

It was 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 was 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 C.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 the ECCS is disabled due to flooding. The assessment of the unavailabilities of the systems in Figure C.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 results of the BNL review[5] of the Shoreham PRA.

- LPCI & LPCS - Based on the result of the BNL review[5] of the 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} was used in the analysis.

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

As noted above, the event tree and failure probabilities in Figure C.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 C.3. These interfacing-line-specific failure probabilities are listed in Table C.5. Sections C.1 to C.3 provide detailed line-by-line analyses for the three reference plants. The overall results for the three plants are summarized in Table C.6.

C.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 were 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 C.7 summarizes the line by line results for the Peach Bottom plant.

C.1.1 Test Requirements for Pressure Isolation Valves

C.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 C.8 lists the PIVs tested and the success criteria used.

C.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 an 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 was not blocked. Therefore, inadvertent opening of the injection valve may lead to an overpressurization of the suction side of the pump.

C.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.

C.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.

C.1.2 LPCI Injection Line

Quantitative analysis for the LPCI injection lines is described in detail in this section and summarized in Table C.9. 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 a high differential pressure across the valve. 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 psid. If the outboard MOV fails to close fully, the operators will have a 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 $3x10^{-3}$ was used for this operator error. Therefore, the probability that the MOV fails to fully reclose and the failure goes undetected is

$$1.07x10^{-4}/\text{demand} * 6 \text{ demands} * 3x10^{-3} = 1.93x10^{-6},$$

where the probability of valve failure is taken from Table C.1. Similarly, the probability that rupture occurs is

$$1.2x10^{-3}/\text{ry} * 0.5 \text{ ry} = 6.0x10^{-4},$$

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 $3x10^{-3}$ was used for such failure and was 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 error during testing or maintenance, or hardware failures in its control logic. This is indicated as MOV "transfer open" in Table C.9. The failure rate, $8.1x10^{-4}$, was 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., $7.35x10^{-4}$ per reactor year.

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

$$1.47x10^{-3} * (1.93x10^{-6} + 6.0x10^{-4} + 3.00x10^{-3} + 4.05x10^{-4}) + 7.35x10^{-4}$$
$$= 7.41x10^{-4}/\text{ry}.$$

To determine the frequency of LOCA in such a 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. This 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} was 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

$$1.47\times10^{-3} * 1.93\times10^{-6} * 0.01 = 2.83\times10^{-11}/yr.$$

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 C.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 the MOV is

$$1.47\times10^{-3} * 6.0\times10^{-4} * 2.65\times10^{-2} * 0.01 = 2.34\times10^{-10}/ry,$$

where 2.65×10^{-2} is the probability that a pipe rupture occurs due to the overpressurization. Similarly, the contribution due to inadvertent opening of the MOV is

$$1.47\times10^{-3} * 3\times10^{-3} * 2.65\times10^{-2} * 0.01 = 1.17\times10^{-9}/ry,$$

the contribution due to transfer opening of the MOV is

$$1.47\times10^{-3} * 4.05\times10^{-4} * 2.65\times10^{-2} * 0.01 = 1.58\times10^{-10}/ry,$$

and the contribution due to the Browns Ferry scenario is

$$7.35\times10^{-4} * 2.65\times10^{-2} * 0.01 = 1.95\times10^{-7}/ry.$$

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

$$1.47\times10^{-3} * 6.0\times10^{-4} * [(1-2.65\times10^{-2}) * 10^{-2}+2.65\times10^{-2} * 9.9\times10^{-3}] = 8.82\times10^{-9}/ry.$$

Similar contribution due to inadvertent opening is

$$1.47\times10^{-3} * 3\times10^{-3} [(1-2.65\times10^{-2}) * 10^{-2} + 2.65\times10^{-2} * 9.9\times10^{-3}] = 4.41\times10^{-8}/ry.$$

The contribution due to transferring open is

$$1.47\times10^{-3} * 4.05\times10^{-4} [(1-2.65\times10^{-2}) * 10^{-2} + 2.65\times10^{-2} * 9.9\times10^{-3}] = 5.95\times10^{-9}/ry.$$

The contribution of the Browns Ferry scenario is

$$7.35\times10^{-4} * [(1-2.65\times10^{-2}) * 10^{-2} + 2.65\times10^{-2} * 9.9\times10^{-3})] = 7.35\times10^{-6}/ry.$$

Table C.9 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. It can be seen in Table C.9 that the Browns Ferry scenario is the dominant contributor to the frequencies of overpressurization, small LOCA and large LOCA in the LPCI lines of Peach

Bottom. This is because the scenario is judged to be an applicable scenario for Peach Bottom and the frequency of overpressurization is estimated using this experience. The fact that this scenario is already covered in the failure combination that the AOV fails due to reversed air supply and the MOV is opened inadvertently, is a double counting. However, the effect of this on the result is negligible, because the Browns Ferry scenario has a frequency that is more than two orders of magnitude higher than that of the failure combinations.

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 were 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 was analyzed in the same way the Browns Ferry-1 incident was analyzed, except that the check valve was not expected to close when a blowdown occurs. The remaining incidents in Table C.9 involve leakage through the testable check valve. They were used to estimate the frequency of check valve leakage. If the MOV also fails open, the leakage was assumed limited by the check valve. Therefore, only a small LOCA was postulated to result.

The results of the above calculations are summarized in Table C.9.

C.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 was considered negligible. Therefore, incidents like that which occurred at Cooper were not considered credible for these lines. Another difference between the core spray lines and the LPCI lines is that the probability of major pipe rupture is different. Table C.10 summarizes the calculation for the core spray lines.

C.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 event will occur. This may cause a transient that leads to feedwater pump trip. However, no interfacing LOCA will occur unless the check valve in the feedwater line also fails open. To account for this, a conditional failure probability of 10^{-1} was used for the check valve when a low pressure pipe rupture occurs and the air-operated check valve fails to close (i.e., a beta factor of 0.1 was assumed).

b. The testable check valves in the HPCI and RCIC lines were not hydrostatically tested in the first ten years of operation. This was 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 stuck open 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, was judged to be credible for the HPCI and RCIC lines at Peach Bottom, because similar tests are also performed. This experience was used to estimate the frequency of this scenario of overpressurization.

The calculations for these lines are shown in Tables C.11 and C.12.

C.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 separated from the battery rooms and the emergency switch gear rooms by a three foot reinforced concrete wall. 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 closed at the ceiling. Therefore, overpressurization failure of building structure as a result of feedwater heater rupture is a potential problem. It is judged that if any structural failure occurs, the most likely failure location is the door that opens outward to the turbine building. 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 visit, it was assumed that ECCS systems were not affected by a rupture of a feedwater heater.

Figure C.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 $1.24\text{x}10^{-4}$. 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 at least 919,153 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 C.2.

C.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 C.1 have been used to analyze the frequency of overpressurization. Two modes of failure were 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 was assumed that the reactor is shutdown once every three months and any valve rupture would 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

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

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.

The RHR suction line is the only interfacing line that contains two valves of the same type, and may be susceptible to common mode failure. The above calculation for the rupture-rupture failure mode assumes that the failures of the two MOVs are independent of each other. The survey of operating experience discussed in Section 3 did not identify any evidence of common mode failures of the RHR suction valves. As a sensitivity study, common mode failure is considered in Appendix F by assuming that the beta factor may take on three possible values, 0, 0.05, and 0.1.

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 considered further.

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

$$P(\text{failure to reclose}) \times 8 \text{ strokes/ry} * \lambda_{Rupture} * 6 \text{ months} = 5.14\times10^{-7}/\text{ry}.$$

C.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 the ECCS. 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 was simply applied as a multiplicative factor to the results for the RHR suction line.

C.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 differences in quantitative results for the ECCS injection lines. For example, NMP-2 performs type "C" leak rate testing 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 C.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 the line-by-line analysis. Table C.13 summarizes the calculations for all of the interfacing lines at Nine Mile Point-2.

C.2.1 Test Requirements for Pressure Isolation Valves

C.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 C.14 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.

C.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.

C.2.1.3 Local Leak Rate Test

The test method has been described in Section C.1.1.3. The test pressure at NMP-2 is 40 psig. All PIVs in the lines listed in Table C.13, 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 were to be reversed, it would be discovered in the post maintenance test.

C.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 was not included in the analysis.

C.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 differences between the two:

a. NMP-2 does not cycle the PIVs in the LPCI lines when the reactor is at power. It was 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 was assumed that a failure mode similar to the air reversal that happened at Browns Ferry-1 and Hatch-2 would 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 would 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 was not included.

d. NMP-2 has only one MOV in each LPCI line, therefore, if a small LOCA occurs due to MOV rupture, it was 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 was assumed to occur in one of the RHR rooms, RCIC was also assumed to be unavailable to mitigate the incident.

Figure C.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} was used in sequence 16 of Figure C.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} was used. This was taken from the BNL review of the Shoreham PRA,[5] i.e., the unavailability of both LPCI AND LPCS. The unavailability of HPCS was taken from RSSMAP Grand Gulf.[8] The first three branches for the top event "X" in Figure C.5 represent human error in depressurization given that a high head system is available. It is similar to the same event in Figure C.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 C.15 summarizes the calculations for LPCI lines.

C.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. Table C.16 summarizes the calculation for LPCS line.

C.2.4 Shutdown Cooling Return to Recirculation

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

C.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 were considered, leakage and rupture. It was 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

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

Pump discharge check valve rupture can occur only after it is pressurized. It was 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 was pressurized for six months. Therefore, the probability that rupture occurs in six months is

$8.8x10^{-4}/ry * 0.5 \text{ year} = 4.4x10^{-4}$.

Table C.17 summarizes the calculation for this line.

C.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 were 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 $\lambda_1 = 2.94x10^{-3}/ry$ and $\lambda_2 = 7.35x10^{-4}/ry$, respectively. Four combinations of failures of the two testable check valves are possible. Their frequencies per year are:

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

The results are listed in Table 4.18. 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 testing 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 C.18. 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 was 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.

C.2.7 Feedwater Line

The analysis for these lines is the same as that for the 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 the MSIVs. 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 would have to fill a large volume in the pipe tunnel underneath the heater bay before it could overflow and threaten the service water system. Therefore, it was assumed that the blowdown does not affect systems needed to mitigate the accident.

C.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 were used.

C.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 C.19 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 open. Assuming F087 can rupture only if it is pressurized, and that F052 is opened for ten minutes, the probability of F087 rupturing is

$$1.2\times10^{-3}/ry * 10/(1440 * 365) = 2.28\times10^{-8}.$$

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

The other failure mode for F052 (rupture) was 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 a dominant contributor to core damage frequency.

The other pair of valves (F218 and F087) is identical to the pair F052 and F087, except that F218 is a one-inch valve. It was 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 again no interlock calibration is performed on F051.

C.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 C.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 the HPCI and RCIC injection lines. This is judged to have no effect on the analysis of RCIC and HPCI lines. When a pipe rupture occurs in these lines, this additional check valve, like two other check valves in the flowpath, should also close and terminate the blowdown. For Peach Bottom, a probability of 10^{-3} was used for common mode failure of two check valves. It was assumed here that the probability that the additional check valve also fails is unity, if the other two valves have already failed due to common cause.

b. The RCIC system at Quad Cities is located in the train B core spray pump room. This tends to affect the calculation in that if a small LOCA occurs in the train B core spray room, the RCIC system will also be unavailable. Due to the assumption that if the operators fail to isolate the small LOCA in 30 minutes RCIC and HPCI will be isolated by high pump room temperature, this difference between Quad Cities and Peach Bottom has no effect on the quantatitive analysis. 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 were to be opened due to reversal of the air supply and the position indication be reversed (as in the Browns Ferry and Hatch events), the failure would go undetected.

d. Quad Cities recently installed a "Safe Shutdown System" which discharges to the discharge line of HPCI and 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 of increasing the frequency of an interfacing LOCA is negligible because the low pressure portion of the system is separated from reactor pressure 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 was assumed that if a small

LOCA results from the overpressurization, both loops of LPCI would be unavailable.

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

The quantitative analysis for Quad Cities is similar to that for Peach Bottom. The line-by-line analysis is provided in Sections C.3.2 to C.3.6. Table C.20 summarizes the results for Quad Cities.

C.3.1 Test Requirements for Pressure Isolation Valves

C.3.1.1 Pressure Isolation Valve Leak Rate Test

No PIV leak rate testing is required for Quad Cities.

C.3.1.2 Valve Operability Test

ECCS injection valves 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.

C.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 the vessel head spray line. These tests are performed every refueling at a test pressure of 48 psi.

C.3.1.4 ECCS Automatic Actuation Test

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

C.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 the valves in the RCIC system and the check valve in the vessel head spray line.

C.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 was 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 was assumed to result. This is why the MOV failure probabilities for valve rupture and transfer opening in Table C.21 are a factor of two higher than those in Table C.9. Since inadvertent opening of the injection valve during auto actuation testing is not considered as discussed above, a generic failure rate for MOVs transferring open was used. The Vermont Yankee event, in which the air-operated check valve was leaking and the normally open injection valve failed to close fully 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 testing without pressure equalization is performed. This experience was used to estimate the frequency of overpressurization due to such a scenario. Such overpressurization was assumed to lead to a small LOCA, because the isolation valves are only leaking. Figure C.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] i.e., 2.2×10^{-2}. 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 C.21 summarizes the calculations for this line.

C.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 not 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 was changed. The low pressure injection function failure probability was 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 C.5. Table C.22 summarizes the calculation for this line.

C.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 second feedwater check valve is judged to have little effect on the analysis due to the consideration of common cause failure. Tables C.23 and C.24 summarize the calculations for these lines.

C.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 was assumed that no ECCS systems would be affected by a large break in any feedwater line, and the same quantitative analysis as that for Peach Bottom can be used.

C.3.6 RHR Suction and Vessel Head Spray

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

C.4 References

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

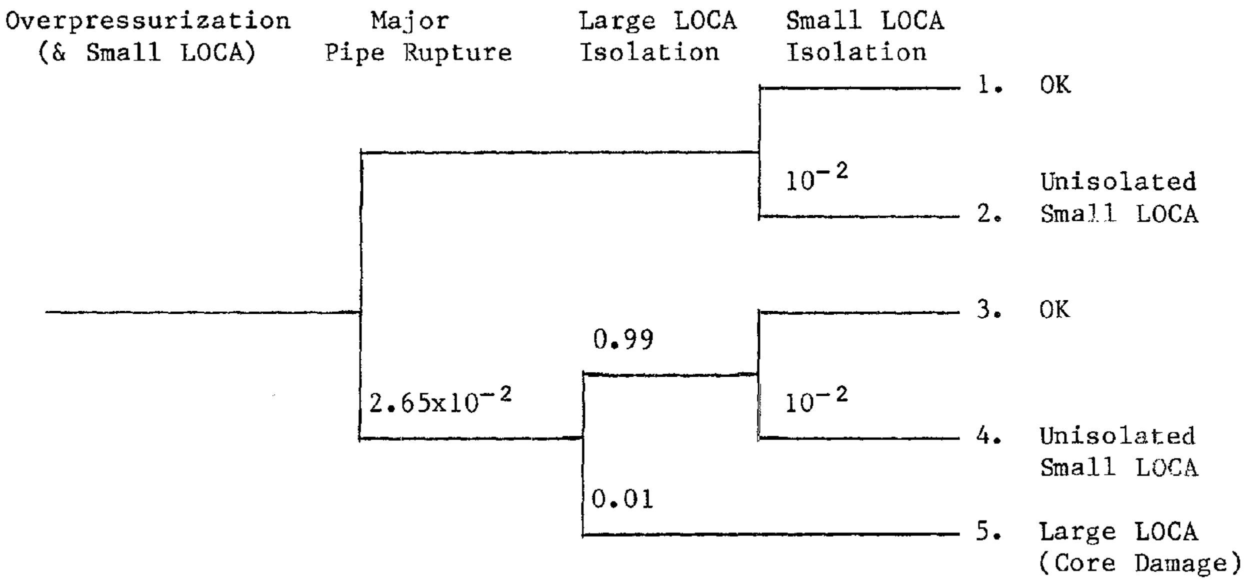

Figure C.1. Event tree for conditional probability of LOCAs resulting from an overpressurization.

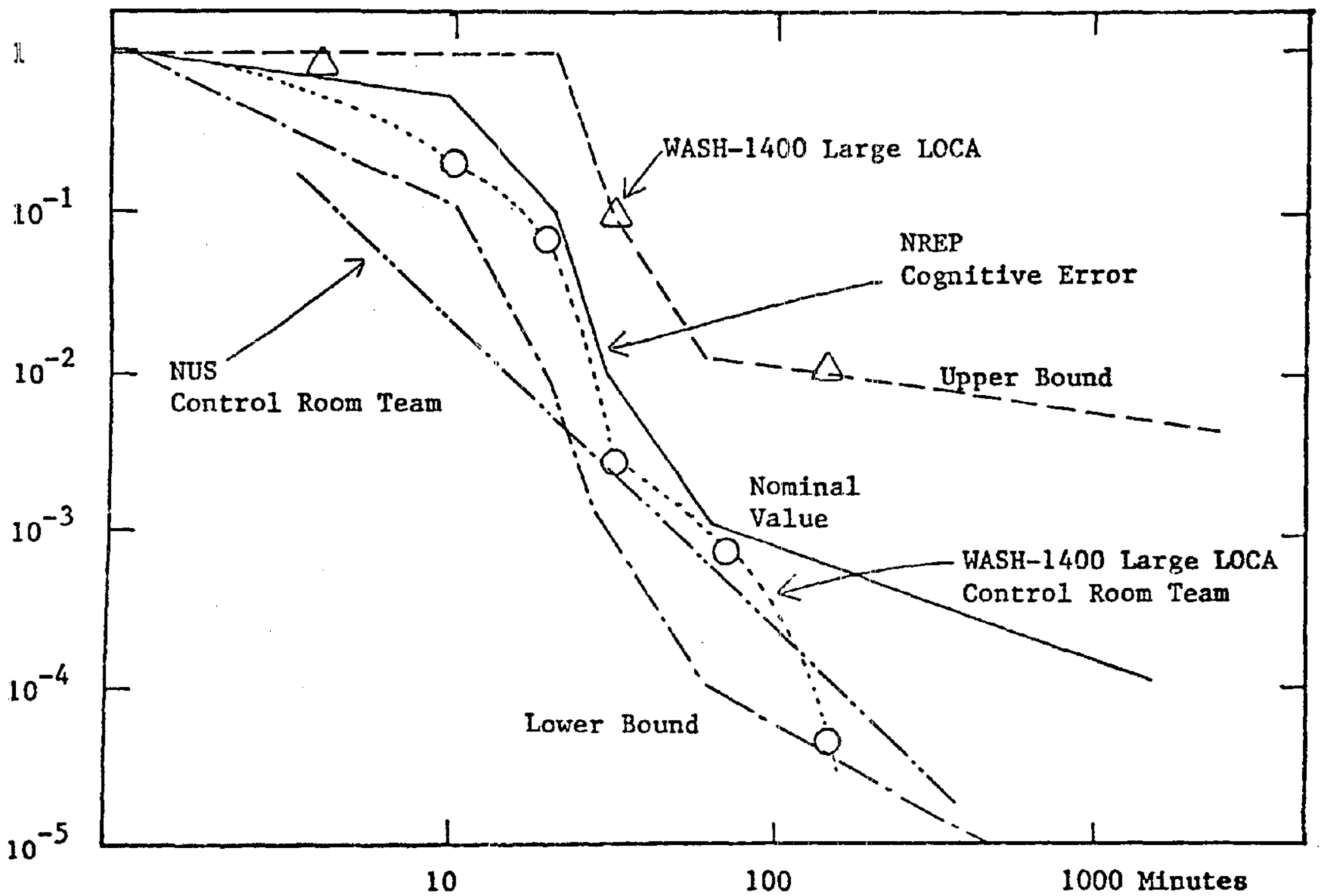

Figure C.2. Time curves for operator actions.

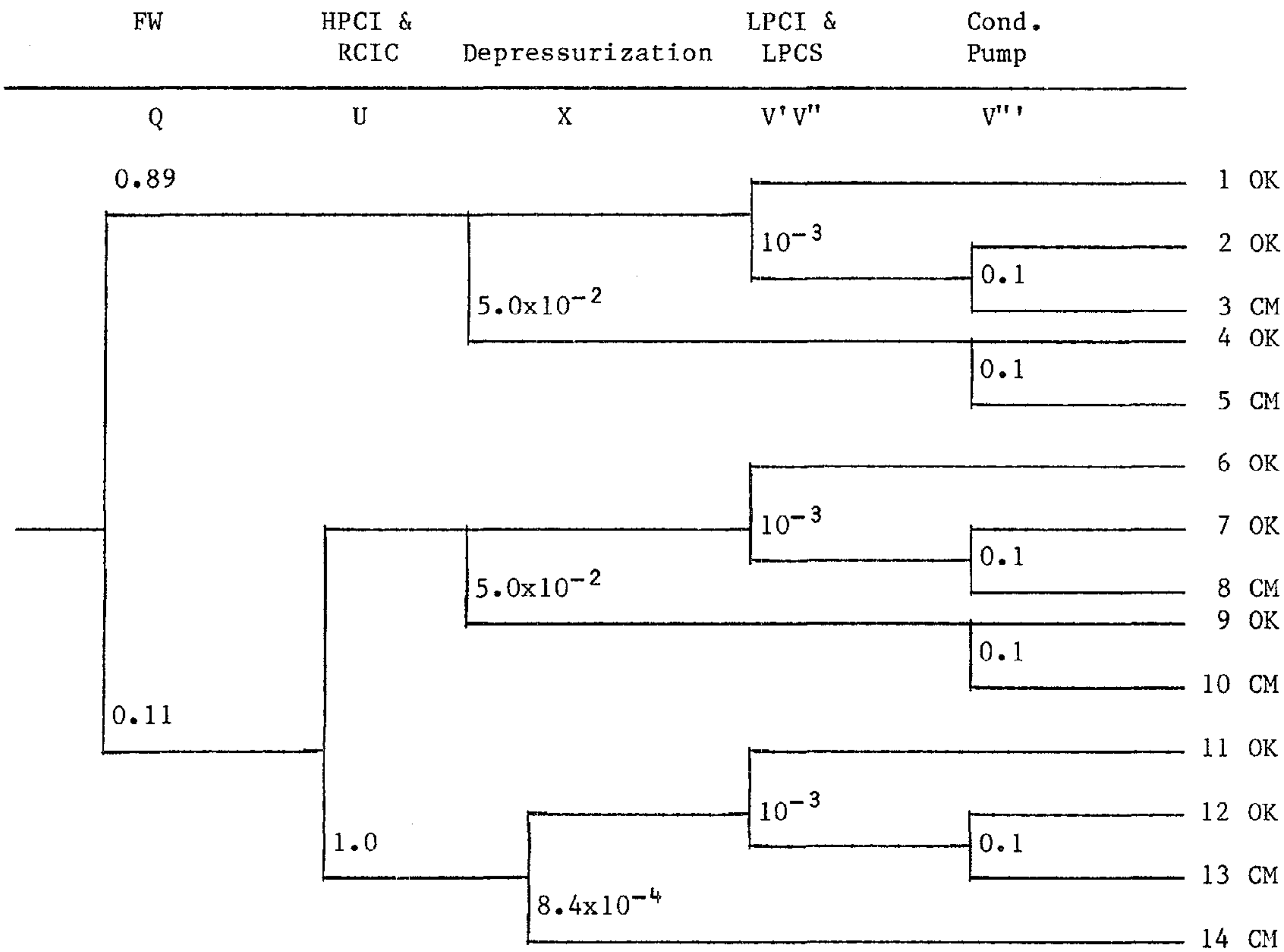

Figure C.3. Event tree for a small LOCA outside the containment (LPCI line at Peach Bottom).

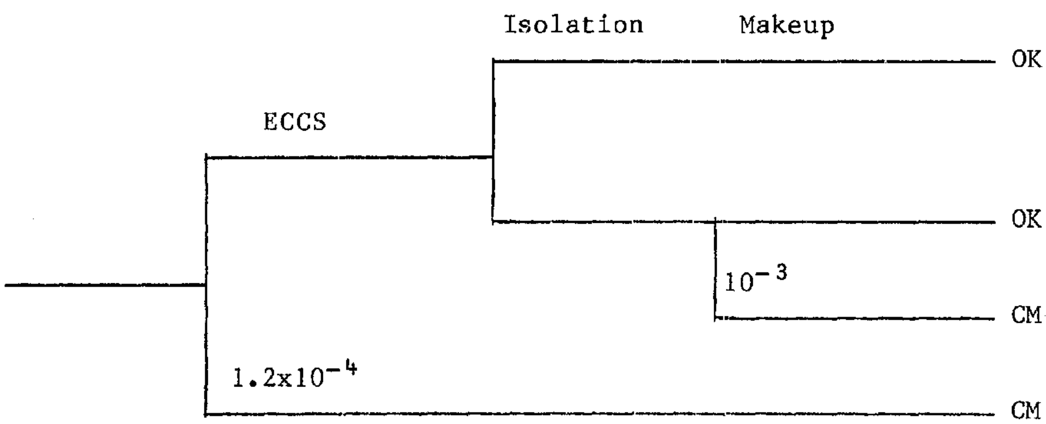

Figure C.4. Event tree for feedwater heater rupture.

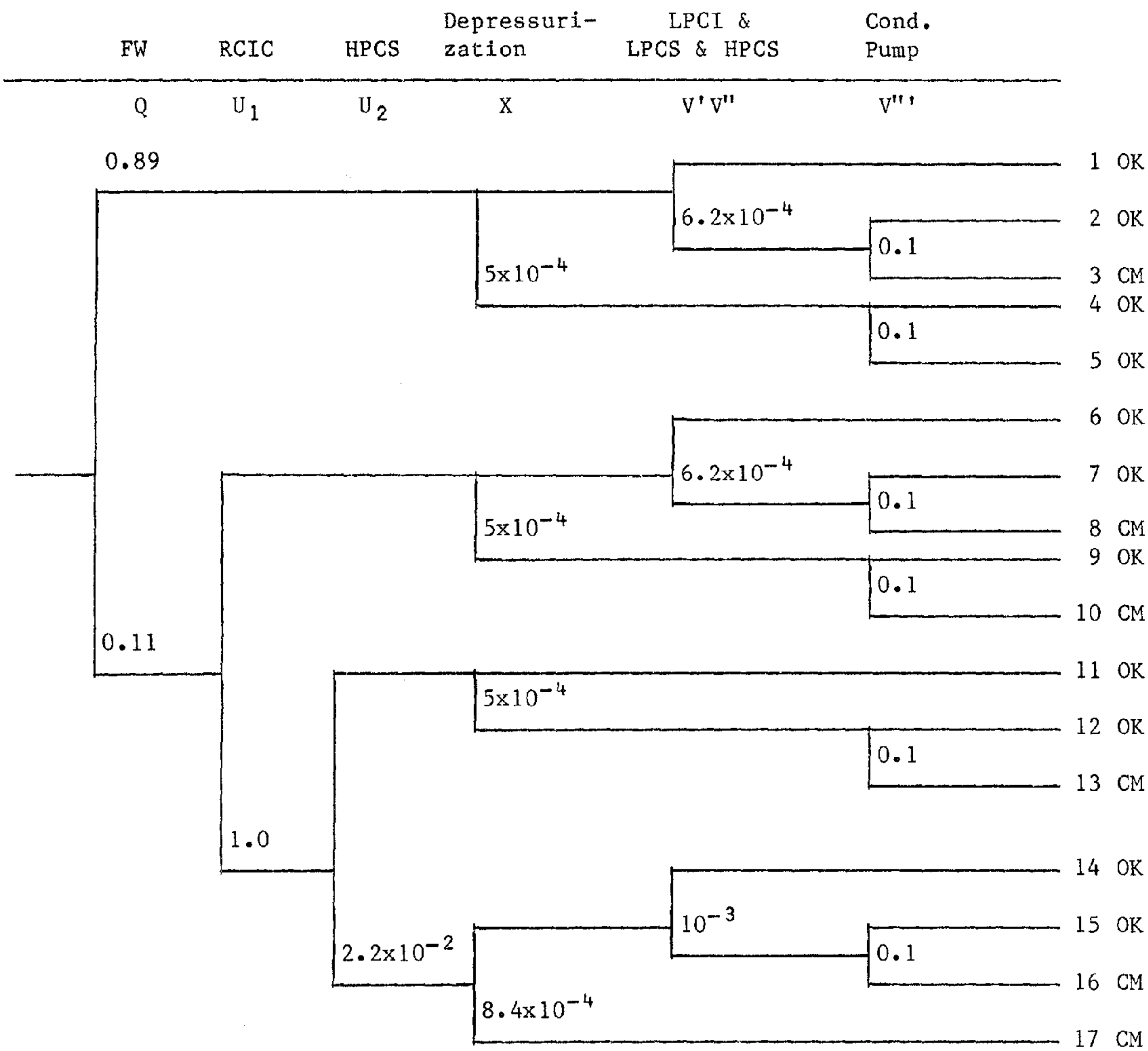

Figure C.5. Event tree for a small LOCA outside the containment (LPCI Line at NMP-2).

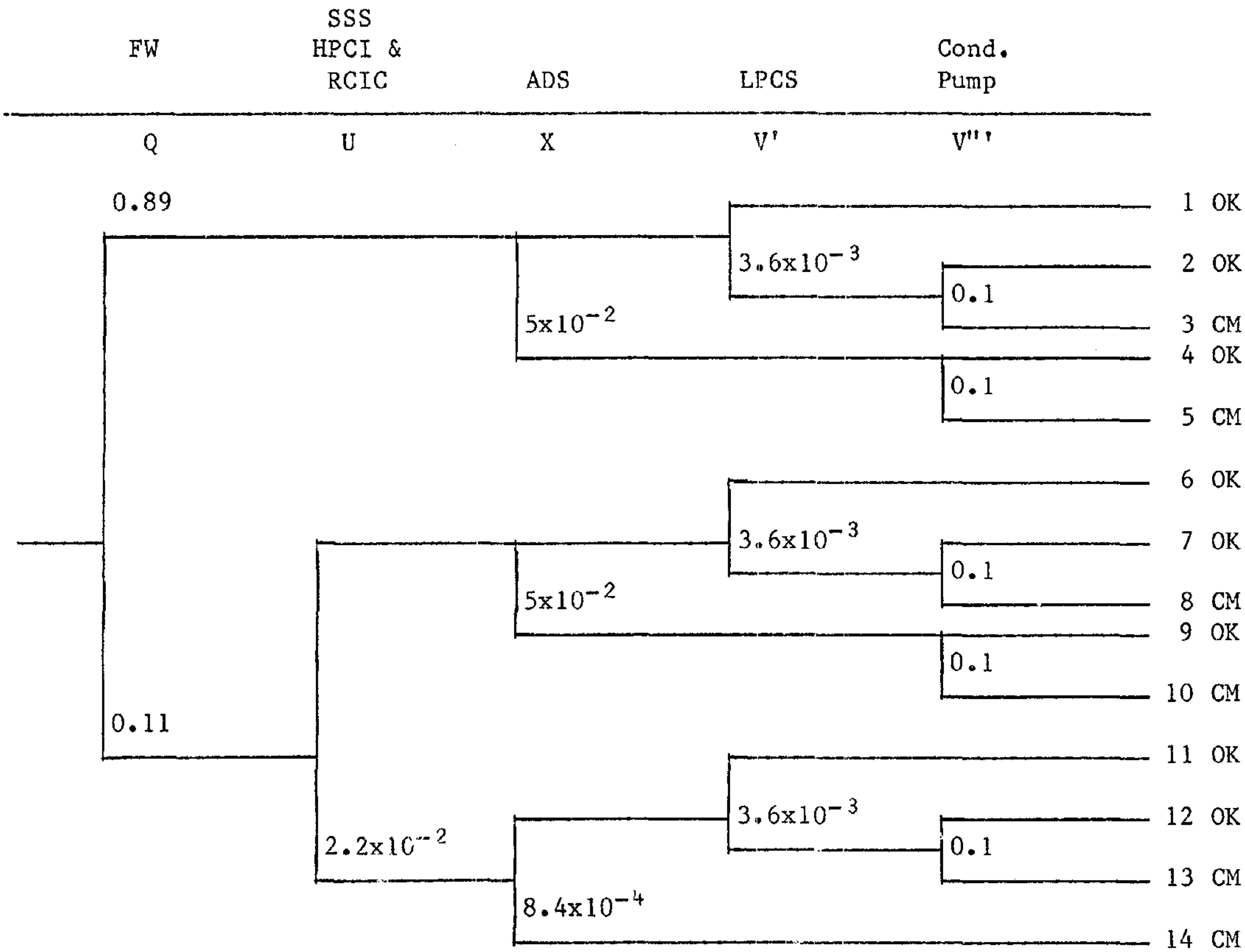

Figure C.6. Event tree for a small LOCA outside the containment (LPCI line at Quad Cities).

Table C.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.

Table C.2
Pipe Rupture Probabilities for Peach Bottom*

Interfacing Lines	Pipe Section	Nominal Pipe Size D (in.)	Pipe Thickness t (in.)	Failure Probability
LPCI and Vessel Head Spray	Injection Line	24	0.5	1.17×10^{-2}
	Vessel Head Spray	6	0.28	1.74×10^{-3}
	Containment Spray	12	0.375	3.95×10^{-3}
	Fuel Pool Cooling	16	0.375	9.34×10^{-3}
	Pump Discharge	20	0.375	2.65×10^{-2}
	Test Line to Suppression Pool	18	0.375	1.58×10^{-2}
RHR Suction	Suction Line	20	0.375	2.65×10^{-2}
	Suction Line	24	0.375	7.48×10^{-2}
	Fuel Pool Cooling	16	0.375	9.34×10^{-3}
Core Spray	Injection Line	12	0.375	3.95×10^{-3}
	Injection Line	14	0.375	5.52×10^{-3}
	Test to Suppression Pool	10	0.365	2.54×10^{-3}
HPCI	Pump Suction	14	0.375	5.52×10^{-3}
	Suction for CST	16	0.375	9.34×10^{-3}
RCIC	Pump Suction	6	0.28	1.74×10^{-3}
Feedwater	Suction Piping	20	0.593	2.81×10^{-3}
	Suction Piping	12	0.375	3.95×10^{-3}

*Taken from Appendix E.

Table C.3
Pipe Rupture Probabilities for Nine Mile Point-2*

Interfacing Lines	Pipe Section	Nominal Pipe Size D (in.)	Pipe Thickness t (in.)	Failure Probability
LPCI, Shutdown Cooling Return, and Steam Condensing	Injection	18	0.5	3.84×10^{-3}
	SDC Return	12	0.375	3.95×10^{-3}
	Drywell Spray	16	0.5	2.63×10^{-3}
	Vessel Head Spray	6	0.28	1.74×10^{-3}
	To S.P. Spray	4	0.237	1.19×10^{-3}
	Fuel Pool Cooling	8	0.322	2.14×10^{-3}
	RCIC Suction	4	0.237	1.19×10^{-3}
	Inlet to HX	20	0.812	1.06×10^{-3}
	Steam Condensing	8	0.5	6.07×10^{-4}
RHR Suction	Suction Line	20	0.5	5.60×10^{-3}
	Suction Line	18	0.375	1.58×10^{-2}
	Fuel Pool	10	0.365	2.54×10^{-3}
LPCS	Injection to S.P.	16	0.5	2.63×10^{-3}
		12	0.375	3.95×10^{-3}
HPCS	Suction from S.P.	14	0.375	5.52×10^{-3}
		3	0.216	9.23×10^{-4}
		20	0.375	2.65×10^{-2}
RCIC	Suction	6	0.28	1.74×10^{-3}
Feedwater	Suction	24	0.968	1.03×10^{-3}

*Taken from Appendix E.

Table C.4
Pipe Rupture Probabilities for Quad Cities*

Interfacing Lines	Pipe Section	Nominal Pipe Size D (in.)	Pipe Thickness t (in.)	Failure Probability
LPCI and Vessel Head Spray	Injection Line	16	0.375	9.34×10^{-3}
	Drywell Spray	10	0.365	2.54×10^{-3}
	Crosstie	18	0.437	6.94×10^{-3}
	Vessel Head Spray to S.P.	4	0.237	1.19×10^{-3}
		14	0.375	5.52×10^{-3}
		6	0.28	1.74×10^{-3}
	Pump Discharge	12	0.375	3.95×10^{-3}
RHR Suction	Suction Line	20	0.375	2.65×10^{-2}
	Fuel Pool Cooling	14	0.375	5.52×10^{-3}
		6	0.28	1.74×10^{-3}
Core Spray	Injection to S.P.	12	0.375	3.95×10^{-3}
		8	0.337	1.81×10^{-3}
HPCI	Suction	16	0.375	9.34×10^{-3}
		4	0.237	1.19×10^{-3}
RCIC	Suction	6	0.28	1.74×10^{-3}
Feedwater	Suction	30	0.625	9.96×10^{-3}
		20	0.5	5.60×10^{-3}
		16	0.375	9.34×10^{-3}
		12	0.375	3.95×10^{-3}

*Taken from Appendix E.

Table C.5
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 C.6
Summary of Results

Plant	f(OP)	S2	A	CDF
Peach Bottom	9.23E-03	3.12E-05	4.82E-06	1.02E-06
Nine Mile Point-2	9.92E-03	6.07E-05	9.83E-06	8.81E-06
Quad Cities	6.89E-03	4.16E-05	1.07E-05	9.32E-07

See Note 1.

Table C.7
Summary of Results for Peach Bottom

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.52E-03	2.65E-02	1.52E-05	7.06E-07	7.77E-07
CS	1.52E-03	5.52E-03	1.52E-05	1.15E-07	1.85E-07
HPCI	2.59E-03	9.34E-03	0.00E+00	2.64E-08	2.64E-08
RCIC	2.59E-03	1.74E-03	0.00E+00	4.91E-09	4.91E-09
Feedwater	1.00E-03	3.95E-03	0.00E+00	3.95E-06	4.42E-09
RHR Suction	7.71E-07	7.48E-02	7.52E-07	1.93E-08	2.27E-08
Vessel Head Spray	4.53E-08	2.65E-02	4.49E-08	4.01E-10	6.10E-10

See Note 2.

Table C.8
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 C.9
Summary Calculations for LPCI of Peach Bottom

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Browns Ferry-1 Hatch-2 (Reverse Air)	1.47E-03	1.93E-06 Failure to Reclose	2.83E-09	0.00E+00	2.83E-11	0.00E+00
		6.00E-04 Rupture	8.82E-07	2.65E-02	8.81E-09	2.34E-10
		3.00E-03 Inadvertent Opening	4.41E-06	2.65E-02	4.41E-08	1.17E-09
		4.05E-04 Transfer Open	5.95E-07	2.65E-02	5.95E-09	1.58E-10
Browns Ferry Scenario (Reverse Air, Inadvertent Opened)			7.35E-04	2.65E-02	7.35E-06	1.95E-07
Cooper (Foreign Material)	7.35E-04	1.93E-06 Failure to Reclose	1.42E-09	0.00E+00	1.42E-11	0.00E+00
		6.00E-04 Rupture	4.41E-07	2.65E-02	4.29E-09	1.17E-08
		3.00E-03 Inadvertent Opening	2.20E-06	2.65E-02	2.15E-08	5.84E-08
		4.05E-04 Transfer Open	2.98E-07	2.65E-02	2.90E-09	7.89E-09
Pilgrim-1 Sept. 29, 1983 (Rusted Linkage)	7.35E-04	1.93E-06 Failure to Reclose	1.42E-09	0.00E+00	1.42E-11	0.00E+00
		6.00E-04 Rupture	4.41E-07	2.65E-02	4.41E-09	1.17E-10
		3.00E-03 Inadvertent Opening	2.20E-06	2.65E-02	2.20E-08	5.84E-10
		4.05E-04 Transfer Open	2.98E-07	2.65E-02	2.97E-09	7.89E-11
LaSalle-1 Sept. 14, 1983 (Misalignment of Gears)	7.35E-04	1.93E-06 Failure to Reclose	1.42E-09	0.00E+00	1.42E-11	0.00E+00
		6.00E-04 Rupture	4.41E-07	2.65E-02	4.29E-09	1.17E-08
		3.00E-03 Inadvertent Opening	2.20E-06	2.65E-02	2.15E-08	5.84E-08
		4.05E-04 Transfer Open	2.98E-07	2.65E-02	2.90E-09	7.89E-09
Four Remaining Incidents (Leakage)	2.94E-03	1.93E-06 Failure to Reclose	5.66E-09	0.00E+00	5.66E-11	0.00E+00
		6.00E-04 Rupture	1.76E-06	0.00E+00	1.76E-08	0.00E+00
		3.00E-03 Inadvertent Opening	8.82E-06	0.00E+00	8.82E-08	0.00E+00
		4.05E-04 Transfer Open	1.19E-06	0.00E+00	1.19E-08	0.00E+00

See Note 3.

Table C.10
Summary Calculations for CS of Peach Bottom

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Browns Ferry-1 Hatch-2 (Reverse Air)	1.47E-03	1.93E-06 Failure to Reclose	2.83E-09	0.00E+00	2.83E-11	0.00E+00
		6.00E-04 Rupture	8.82E-07	5.52E-03	8.82E-09	4.87E-11
		3.00E-03 Inadvertent Opening	4.41E-06	5.52E-03	4.41E-08	2.43E-10
		4.05E-04 Transfer Open	5.95E-07	5.52E-03	5.95E-09	3.29E-11
Browns Ferry Scenario (Reverse Air, Inadvertent Opening)			7.35E-04	5.52E-03	7.35E-06	4.06E-08
Pilgrim-1 Sept. 29,1983 (Rusted Linkage)	7.35E-04	1.93E-06 Failure to Reclose	1.42E-09	0.00E+00	1.42E-11	0.00E+00
		6.00E-04 Rupture	4.41E-07	5.52E-03	4.41E-09	2.43E-11
		3.00E-03 Inadvertent Opening	2.20E-06	5.52E-03	2.20E-08	1.22E-10
		4.05E-04 Transfer Open	2.98E-07	5.52E-03	2.98E-09	1.64E-11
LaSalle-1 Sept. 14,1983 (Misalignment of Gears)	7.35E-04	1.93E-06 Failure to Reclose	1.42E-09	0.00E+00	1.42E-11	0.00E+00
		6.00E-04 Rupture	4.41E-07	5.52E-03	4.38E-09	2.43E-09
		3.00E-03 Inadvertent Opening	2.20E-06	5.52E-03	2.19E-08	1.22E-08
		4.05E-04 Transfer Open	2.98E-07	5.52E-03	2.96E-09	1.64E-09
Four Remaining Incidents (Leakage)	2.94E-03	1.93E-06 Failure to Reclose	5.66E-09	0.00E+00	5.66E-11	0.00E+00
		6.00E-04 Rupture	1.76E-06	0.00E+00	1.76E-08	0.00E+00
		3.00E-03 Inadvertent Opening	8.82E-06	0.00E+00	8.82E-08	0.00E+00
		4.05E-04 Transfer Open	1.19E-06	0.00E+00	1.19E-08	0.00E+00

ee Note 3.

Table C.11
Summary of Calculations for HPCI of Peach Bottom

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Browns Ferry-1 Hatch-2 (Reversed Air)	1.47E-02	1.20E-03 Rupture	1.76E-05	9.34E-03	0.00E+00	1.65E-10
		6.00E-03 Inadvertent Opening	8.82E-05	9.34E-03	0.00E+00	8.24E-10
		8.10E-04 Transfer Open	1.19E-05	9.34E-03	0.00E+00	1.11E-10
Browns Ferry Scenario (Reverse Air, Inadvertent Opened)			7.35E-04	9.34E-03	0.00E+00	6.86E-09
Cooper (Foreign Material)	7.35E-03	1.20E-03 Rupture	8.82E-06	9.34E-03	0.00E+00	8.24E-10
		6.00E-03 Inadvertent Opening	4.41E-05	9.34E-03	0.00E+00	4.12E-09
		8.10E-04 Transfer Open	5.95E-06	9.34E-03	0.00E+00	5.56E-10
Pilgrim-1 Sept. 29,1983 (Rusted Linkage)	7.35E-03	1.20E-03 Rupture	8.82E-06	9.34E-03	0.00E+00	8.24E-11
		6.00E-03 Inadvertent Opening	4.41E-05	9.34E-03	0.00E+00	4.12E-10
		8.10E-04 Transfer Open	5.95E-06	9.34E-03	0.00E+00	5.56E-11
Pilgrim Scenario (Rusted Linkage, HE in Testing)			7.35E-04	9.34E-03	0.00E+00	6.86E-09
LaSalle-1 Sept. 14,1983 (Misalignment of Gears)	7.35E-03	1.20E-03 Rupture	8.82E-06	9.34E-03	0.00E+00	8.24E-10
		6.00E-03 Inadvertent Opening	4.41E-05	9.34E-03	0.00E+00	4.12E-09
		8.10E-04 Transfer Open	5.95E-06	9.34E-03	0.00E+00	5.56E-10

See Note 3.

Table C.12
Summary of Calculations for RCIC of Peach Bottom

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Browns Ferry-1 Hatch-2 (Reversed Air)	1.47E-02	1.20E-03 Rupture	1.76E-05	1.74E-03	0.00E+00	3.07E-11
		6.00E-03 Inadvertent Opening	8.82E-05	1.74E-03	0.00E+00	1.53E-10
		8.10E-04 Transfer Open	1.19E-05	1.74E-03	0.00E+00	2.07E-11
Browns Ferry Scenario (Reverse Air, Inadvertent Opened)			7.35E-04	1.74E-03	0.00E+00	1.28E-09
Cooper (Foreign Material)	7.35E-03	1.20E-03 Rupture	8.82E-06	1.74E-03	0.00E+00	1.53E-10
		6.00E-03 Inadvertent Opening	4.41E-05	1.74E-03	0.00E+00	7.67E-10
		8.10E-04 Transfer Open	5.95E-06	1.74E-03	0.00E+00	1.04E-10
Pilgrim-1 Sept. 29,1983 (Rusted Linkage)	7.35E-03	1.20E-03 Rupture	8.82E-06	1.74E-03	0.00E+00	1.53E-11
		6.00E-03 Inadvertent Opening	4.41E-05	1.74E-03	0.00E+00	7.67E-11
		8.10E-04 Transfer Open	5.95E-06	1.74E-03	0.00E+00	1.04E-11
Pilgrim Scenario (Rusted Linkage, HE in Testing)			7.35E-04	1.74E-03	0.00E+00	1.28E-09
LaSalle-1 Sept. 14,1983 (Misalignment of Gears)	7.35E-03	1.20E-03 Rupture	8.82E-06	1.74E-03	0.00E+00	1.53E-10
		6.00E-03 Inadvertent Opening	4.41E-05	1.74E-03	0.00E+00	7.67E-10
		8.10E-04 Transfer Open	5.95E-06	1.74E-03	0.00E+00	1.04E-10

See Note 3.

Table C.13
Summary of Results for Nine Mile Point-2

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	1.33E-05	3.95E-03	7.98E-06	8.84E-09	9.97E-09
LPCS	3.69E-06	3.95E-03	2.22E-06	2.92E-11	3.43E-10
SDC Return	8.86E-06	3.95E-03	5.32E-06	5.89E-09	6.64E-09
HPCS	2.65E-07	2.65E-02	2.65E-07	8.61E-14	5.29E-11
Vessel Head Spray	4.35E-06	1.74E-03	5.05E-08	9.28E-13	2.21E-10
Feedwater	1.00E-03	1.03E-03	0.00E+00	1.03E-06	1.15E-09
RHR Suction	7.71E-07	1.58E-02	7.67E-07	4.07E-09	4.15E-09
Steam Condensing	8.89E-03	3.95E-03	4.40E-05	8.78E-06	8.78E-06

See Note 2.

Table C.14
PIVs Tested in PIV Leak Rate Test at Nine Mile Point-2

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 C.15
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	3.95E-03	4.39E-07	1.74E-09
		4.05E-04 Transfer Open	2.98E-07	3.95E-03	2.96E-09	1.18E-09
Pilgrim-1 Sept. 29,1983 (Rusted Linkage)	7.35E-04	6.00E-04 Rupture	4.41E-07	3.95E-03	4.41E-07	1.74E-11
		4.05E-04 Transfer Open	2.98E-07	3.95E-03	2.98E-09	1.18E-11
Four Remaining Incidents (Leakage)	2.94E-03	6.00E-04 Rupture	1.76E-06	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

See Note 3.

Table C.16
Summary Calculations for LPCS of Nine Mile Point-2

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Pilgrim-1 Sept. 29,1983 (Rusted Linkage)	7.35E-04	6.00E-04 Rupture	4.41E-07	3.95E-03	4.41E-07	1.74E-11
		4.05E-04 Transfer Open	2.98E-07	3.95E-03	2.98E-09	1.18E-11
Four Remaining Incidents (Leakage)	2.94E-03	6.00E-04 Rupture	1.76E-06	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

See Note 3.

Table C.17
Summary Calculations for HPCS of Nine Mile Point-2

Experience	AOV	MOV	Check	f(OP)	P(Rupture)	S2	A
Pilgrim-1 Sept. 29,1983 (Rusted Linkage)	7.35E-04	2.14E-04 Failure to Reclose	5.88E-02 Leak	9.25E-09	0.00E+00	9.25E-09	0.00E+00
			4.40E-04 Rupture	6.92E-11	0.00E+00	6.92E-11	0.00E+00
		6.00E-04 Rupture	5.88E-02 Leak	2.59E-08	0.00E+00	2.59E-08	0.00E+00
			4.40E-04 Rupture	1.94E-10	2.65E-02	1.94E-10	5.14E-14
		4.05E-04 Transfer Open	5.88E-02 Leak	1.75E-08	0.00E+00	1.75E-08	0.00E+00
			4.40E-04 Rupture	1.31E-10	2.65E-02	1.31E-10	3.47E-14
Four Remaining Incidents (Leakage)	2.94E-03	2.14E-04 Failure to Reclose	5.88E-02 Leak	3.70E-08	0.00E+00	3.70E-08	0.00E+00
			4.40E-04 Rupture	2.77E-10	0.00E+00	2.77E-10	0.00E+00
		6.00E-04 Rupture	5.88E-02 Leak	1.04E-07	0.00E+00	1.04E-07	0.00E+00
			4.40E-04 Rupture	7.76E-10	0.00E+00	7.76E-10	0.00E+00
		4.05E-04 Transfer Open	5.88E-02 Leak	7.00E-08	0.00E+00	7.00E-08	0.00E+00
			4.40E-04 Rupture	5.24E-10	0.00E+00	5.24E-10	0.00E+00

Check = Check Valve Failure Probability.
See Note 3.

Table C.18
Summary of Calculations for Vessel Head Spray of Nine Mile Point-2

Experience AOV1 AOV2	AOV	MOV	f(OP)	P(Rupture)	S2	A
Leak+Leak	5.45E-06	2.14E-04 Failure to Reclose	1.63E-09	0.00E+00	1.63E-09	0.00E+00
Leak+Rusted Linkage	1.08E-06					
Rusted Linkage+Leak	1.08E-06	6.00E-04 Rupture	4.57E-09	0.00E+00	4.57E-09	0.00E+00
Total	7.61E-06					
		5.00E-01 Open in Test	3.80E-06	0.00E+00	3.80E-08	0.00E+00
		4.05E-04 Transfer Open	3.08E-09	0.00E+00	3.08E-11	0.00E+00
Rusted Linkage(both)	1.06E-06	2.14E-04 Failure to Reclose	2.28E-10	0.00E+00	2.28E-10	0.00E+00
		6.00E-04 Rupture	6.39E-10	1.74E-03	6.39E-10	1.11E-15
		5.00E-01 Open in Test	5.32E-07	1.74E-03	5.32E-09	9.27E-13
		4.05E-04 Transfer Open	4.31E-10	1.74E-03	4.31E-12	7.51E-16

See Note 3.

Table C.19
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 Cycling per ry	2.28E-08 Rupture	9.13E-08	3.95E-03	3.62E-10	1.80E-10
		2.02E-04 Transfer Open	8.10E-04	3.95E-03	3.21E-06	1.60E-06
	1.20E-03 Rupture	1.50E-04 Rupture	2.58E-07	3.95E-03	1.02E-09	5.09E-10
		5.00E-01 Interlock Calibration	6.00E-04	3.95E-03	2.38E-06	1.19E-06
		8.10E-04 Transfer Open	9.72E-07	3.95E-03	3.86E-09	1.92E-09
F218&F087	4.00E+00 Cycling per ry	2.28E-08 Rupture	9.13E-08	3.95E-03	5.43E-10	0.00E+00
		2.02E-04 Transfer Open	8.10E-04	3.95E-03	4.81E-06	0.00E+00
	1.20E-03 Rupture	1.50E-04 Rupture	2.58E-07	3.95E-03	1.53E-09	0.00E+00
		5.00E-01 Interlock Calibartion	6.00E-04	3.95E-03	3.57E-06	0.00E+00
		8.10E-04 Transfer Open	9.72E-07	3.95E-03	5.78E-09	0.00E+00
F052&F051	4.00E+00 Cycling per ry	2.28E-08 Rupture	9.13E-08	3.95E-03	3.62E-10	1.80E-10
		2.02E-04 Transfer Open	8.10E-04	3.95E-03	3.21E-06	1.60E-06
	1.20E-03 Rupture	1.50E-04 Rupture	2.58E-07	3.95E-03	1.02E-09	5.09E-10
		8.10E-04 Transfer Open	9.72E-07	3.95E-03	3.86E-09	1.92E-09
F218&F051	4.00E+00 Cycling per ry	2.28E-08 Rupture	9.13E-08	3.95E-03	5.43E-10	0.00E+00
		2.02E-04 Transfer Open	8.10E-04	3.95E-03	4.81E-06	0.00E+00
	1.20E-03 Rupture	1.50E-04 Rupture	2.58E-07	3.95E-03	1.53E-09	0.00E+00
		8.10E-04 Transfer Open	9.72E-07	3.95E-03	5.78E-09	0.00E+00

See Note 3.

Table C.20
Summary of Results for Quad Cities

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	2.07E-03	9.34E-03	2.07E-05	5.60E-07	6.71E-07
CS	2.01E-03	3.95E-03	2.01E-05	1.20E-07	2.28E-07
HPCI	9.03E-04	9.34E-03	0.00E+00	8.79E-09	8.79E-09
RCIC	9.03E-04	1.74E-03	0.00E+00	1.64E-09	1.64E-09
Feedwater	1.00E-03	9.96E-03	0.00E+00	9.96E-06	1.12E-08
RHR Suction	7.71E-07	2.65E-02	7.64E-07	6.82E-09	1.09E-08
Vessel Head Spray	4.53E-08	9.34E-03	4.52E-08	1.41E-10	3.84E-10

See Note 2.

Table C.21
Summary Calculations for LPCI of Quad Cities

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Browns Ferry-1 Hatch-2 (Reverse Air)	1.47E-02	2.57E-03 Failure to Reclose	3.77E-05	0.00E+00	3.77E-07	0.00E+00
		1.20E-03 Rupture	1.76E-05	9.34E-03	1.76E-07	1.65E-09
		8.10E-04 Transfer Open	1.19E-05	9.34E-03	1.19E-07	1.11E-09
Cooper (Foreign Material)	7.35E-03	2.57E-03 Failure to Reclose	1.89E-05	0.00E+00	1.89E-07	0.00E+00
		1.20E-03 Rupture	8.82E-06	9.34E-03	8.73E-08	8.24E-08
		8.10E-04 Transfer Open	5.95E-06	9.34E-03	5.90E-08	5.56E-08
Pilgrim-1 Sept. 29,1983 (Rusted Linkage)	7.35E-03	2.57E-03 Failure to Reclose	1.89E-05	0.00E+00	1.89E-07	0.00E+00
		1.20E-03 Rupture	8.82E-06	9.34E-03	8.82E-08	8.24E-10
		8.10E-04 Transfer Open	5.95E-06	9.34E-03	5.95E-08	5.56E-10
LaSalle-1 Sept. 14,1983 (Misalignment of Gears)	7.35E-03	2.57E-03 Failure to Reclose	1.89E-05	0.00E+00	1.89E-07	0.00E+00
		1.20E-03 Rupture	8.82E-06	9.34E-03	8.73E-08	8.24E-08
		8.10E-04 Transfer Open	5.95E-06	9.34E-03	5.90E-08	5.56E-08
Four Remaining Incidents (Leak)	2.94E-02	2.57E-03 Failure to Reclose	7.55E-05	0.00E+00	7.55E-07	0.00E+00
		1.20E-03 Rupture	3.53E-05	0.00E+00	3.53E-07	0.00E+00
		8.10E-04 Transfer Open	2.38E-05	0.00E+00	2.38E-07	0.00E+00
Vermont Yankee Scenario (Leak, Failure to Fully Close)			7.35E-04	0.00E+00	7.35E-06	0.00E+00

See Note 3.

Table C.22
Summary Calculations for CS of Quad Cities

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Browns Ferry-1 Hatch-2 (Reverse Air)	1.47E-02	2.57E-03 Failure to Reclose	3.77E-05	0.00E+00	3.77E-07	0.00E+00
		1.20E-03 Rupture	1.76E-05	3.95E-03	1.76E-07	6.97E-10
		8.10E-04 Transfer Open	1.19E-05	3.95E-03	1.19E-07	4.70E-10
Pilgrim-1 Sept. 29,1983 (Rusted Linkage)	7.35E-03	2.57E-03 Failure to Reclose	1.89E-05	0.00E+00	1.89E-07	0.00E+00
		1.20E-03 Rupture	8.82E-06	3.95E-03	8.82E-08	3.48E-10
		8.10E-04 Transfer Open	5.95E-06	3.95E-03	5.95E-08	2.35E-10
LaSalle-1 Sept. 14,1983 (Misalignment of Gears)	7.35E-03	2.57E-03 Failure to Reclose	1.89E-05	0.00E+00	1.89E-07	0.00E+00
		1.20E-03 Rupture	8.82E-06	3.95E-03	8.78E-08	3.48E-08
		8.10E-04 Transfer Open	5.95E-06	3.95E-03	5.93E-08	2.35E-08
Four Remaining Incidents (Leak)	2.94E-02	2.57E-03 Failure to Reclose	7.55E-05	0.00E+00	7.55E-07	0.00E+00
		1.20E-03 Rupture	3.53E-05	0.00E+00	3.53E-07	0.00E+00
		8.10E-04 Transfer Open	2.38E-05	0.00E+00	2.38E-07	0.00E+00
Vermont Yankee Scenario (Leak, Failure to Fully Close)			7.35E-04	0.00E+00	7.35E-06	0.00E+00

See Note 3.

Table C.23
Summary of Calculations for HPCI of Quad Cities

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Browns Ferry-1 Hatch-2 (Reverse Air)	1.47E-02	1.20E-03 Rupture	1.76E-05	9.34E-03	0.00E+00	1.65E-10
		8.10E-04 Transfer Open	1.19E-05	9.34E-03	0.00E+00	1.11E-10
Cooper (Foreign Material)	7.35E-03	1.20E-03 Rupture	8.82E-06	9.34E-03	0.00E+00	8.24E-11
		8.10E-04 Transfer Open	5.95E-06	9.34E-03	0.00E+00	5.56E-11
Pilgrim-1 Sept. 29,1983 (Rusted Linkage)	7.35E-03	1.20E-03 Rupture	8.82E-06	9.34E-03	0.00E+00	8.24E-11
		8.10E-04 Transfer Open	5.95E-06	9.34E-03	0.00E+00	5.56E-11
Pilgrim Scenario (Rusted Linkage, HE in Testing)			7.35E-04	9.34E-03	0.00E+00	6.86E-09
LaSalle-1 Sept. 14,1983 (Misalignment of Gears)	7.35E-03	1.20E-03 Rupture	8.82E-06	9.34E-03	0.00E+00	8.24E-10
		8.10E-04 Transfer Open	5.95E-06	9.34E-03	0.00E+00	5.56E-10

See Note 3.

Table C.24
Summary of Calculations for RCIC of Quad Cities

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Browns Ferry-1 Hatch-2 (Reverse Air)	1.47E-02	1.20E-03 Rupture	1.76E-05	1.74E-03	0.00E+00	3.07E-11
		8.10E-04 Transfer Open	1.19E-05	1.74E-03	0.00E+00	2.07E-11
		2.57E-03 Failure to Reclose	1.89E-05	0.00E+00	0.00E+00	0.00E+00
Cooper (Foreign Material)	7.35E-03	1.20E-03 Rupture	8.82E-06	1.74E-03	0.00E+00	1.53E-11
		8.10E-04 Transfer Open	5.95E-06	1.74E-03	0.00E+00	1.04E-11
Pilgrim-1 Sept. 29,1983 (Rusted Linkage)	7.35E-03	1.20E-03 Rupture	8.82E-06	1.74E-03	0.00E+00	1.53E-11
		8.10E-04 Transfer Open	5.95E-06	1.74E-03	0.00E+00	1.04E-11
Pilgrim Scenario (Rusted Linkage, HE in Testing)			7.35E-04	1.74E-03	0.00E+00	1.28E-09
LaSalle-1 Sept. 14,1983 (Misalignment of Gears)	7.35E-03	1.20E-03 Rupture	8.82E-06	1.74E-03	0.00E+00	1.53E-10
		8.10E-04 Transfer Open	5.95E-06	1.74E-03	0.00E+00	1.04E-10

See Note 3.

Notes for Appendix C Tables

Note 1: f(OP) = Frequency of Overpressurization (/ry).
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
CDF = Core Damage Frequency (/ry).

Note 2: 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).

Note 3: AOV = Failure Rate of Air-Operated Check Valve (/ry).
MOV = Probability of MOV Failure.
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).

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. An 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 the 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 was estimated to be 4173 valve years. Therefore, the failure rate was 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 an 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 was 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 an MOV fails to close fully after being opened, such that the valve is leaking while the indication in the control room shows the valve to be closed. The failure data for this failure mode was also taken from the Seabrook PSA. This failure mode results in limited leakage through the valve. If an interfacing LOCA occurs with an 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 was taken from the handbook for human reliability analysis.[3] The probability of error of omission in use of written procedures, with check off 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 were 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 was estimated using the region I Event-V report and FSARs, and the number of reactor years was estimated based on the Grey Book. The number of valve years was 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 was 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 was 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 was 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 was 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 was 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 was 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 were 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 an MOV, given in the PSA Procedure Guide,[4] was used as a prior distribution. A Bayes update using the evidence of five events in 4173 years was performed. The mean of the square was calculated using the discretized probability distribution for the posterior distribution.

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

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

The corresponding variance is 1.05×10^{-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. Guttman, "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.

APPENDIX E: Interfacing LOCA Pipe Break Probability

An estimate of the likelihood that the low pressure piping in a particular plant will fail when subjected to overpressurization is an essential item needed to assess the core damage frequency resulting from an interfacing system LOCA. The purpose of this appendix is to establish a reasonable pipe rupture probability associated with interfacing LOCA in both BWRs and PWRs. This pipe failure probability estimate is based on the limited amount of data available in this area and on a good deal of engineering judgement.

Review of Industry Estimates of Pipe Failure During Interfacing LOCA

As an initial step, the sections dealing with pipe rupture of three industry documents on the subject of interfacing LOCA were reviewed:

1. "Seabrook Station Risk Management and Emergency Planning Study," PLG-0432, December 1985.

2. Fauske & Associates, Inc., "Evaluation of Containment Bypass and Failure to Isolate Sequences for the IDCOR Reference Plants," Draft Report FAI/84-9, July 1984.

3. Draft of GE Report, "BWR Owners Group Assessment of Emergency Core Cooling System Pressurization in Boiling Water Reactors," by Mehta and Howard.

For convenience, these reports are referred to as Seabrook, IDCOR, and BWROG in the subsequent discussion.

Section 3 of Seabrook, entitled "SSPSA Plant Model Update," briefly discusses the Seabrook RHR piping strength and rupture probability. Seabrook states that the piping involved is Schedule 40, 304 stainless steel piping with a maximum diameter of 16 inches on the suction side. While the pipe is designed for a pressure of 600 psig, during an interfacing LOCA it may experience a pressure of 2,250 psia. Seabrook proceeds to model the overpressurization as quasi-static, based on the arguments made in the IDCOR report (discussed here later). The conclusion stated in Seabrook is that, with a 2250 psia pressure, the hoop stress σ_h will approach the yield stress of 35 ksi (kilopounds per square inch). (This can be easily verified. For a Schedule 40, 16 inch pipe

$$\sigma_h = \frac{2{,}250 \text{ psi } (15.5)}{2\ (.5)} = 34.88 \text{ ksi}) \text{ .}$$

To obtain a failure probability, Seabrook assumes a log-normal distribution for which the probability of failure at yield is .01 and at the ultimate stress is 0.99. The calculated hoop stress, slightly below yield, then corresponds to a failure probability of 0.006. Seabrook also assumes a 'flat' distribution of a 10^{-3} failure probability to account for such things as undetected design errors, material defects, etc. In other words, independent of the magnitude of the internal pressure, the pipe rupture probability is never less than 0.001.

The following observations can be made regarding the Seabrook method: First, the yield stress of 35 ksi cited above, may be nonconservative for the 500 to 600°F temperature the pipe experiences. A standard reference work on stainless steels[1] gives a value of 24 ksi as the yield for 304 SS at 500°F. If the same criteria for a probability distribution were used as before, i.e., log normal with a .01 failure probability at yield, then the calculated hoop stress of 34.88 ksi would lead to a probability of failure considerably greater then .01. No reduction of pipe thickness due to corrosion was considered. Finally, like the other two references, Seabrook treats the problem only quasi-statically.

The IDCOR document considers interfacing system LOCA in four reference plants: Peach Bottom, Grand Gulf, Zion and Sequoyah. No probabilistic analysis is made regarding pipe breaks. Instead, hoop stresses are compared to pipe strength in a deterministic way with the conclusion that low pressure piping would remain intact long after the shaft seals of the RHR pumps fail. For Peach Bottom, IDCOR describes 20 inch piping made of ASTM A106 B with a wall thickness of 0.95 cm (0.375 in.). According to IDCOR, this piping could be exposed to pressures approaching 7 MPa (megapascals) (1,000 psia). The subsequent stress calculations in IDCOR are difficult to make sense of: For the pipe described at 7 MPa of internal pressure, IDCOR cites a hoop stress of 375 MPa. This is clearly wrong. The correct stress is only

$$\frac{7\ \text{MPa}\ (49.85\ \text{cm})}{2\ (.95\ \text{cm})} = 184\ \text{MPa}\ (26.6\ \text{ksi})\ .$$

However, IDCOR also cites the yield stress for A-106 Grade B as 414 MPa (60 ksi) but this value is actually the ultimate stress of this material. The yield stress is only 241 MPa (35 ksi) at room temperature and more like 186 MPa (27 ksi) for 500°F temperature service. Therefore the calculated hoop stress, 184 MPa, is about 99% of the yield stress of 186 MPa. No allowance for corrosion has been made and no dynamic effects are considered.

For Zion, IDCOR considers a 14 inch, Schedule 40 pipe of 316 stainless steel with an inside diameter of 0.33 m and a wall thickness of 1.1 cm. This low pressure piping could be exposed to 15.5 MPa (2,250 psia) according to IDCOR. The resulting hoop stress is correctly cited as 233 MPa (33.8 ksi) but the yield stress for 316 SS is given by IDCOR as 552 MPa (80 ksi). This again is an ultimate stress not a yield stress. 316 SS has a yield[1] of about 276 MPa (40 ksi) at room temperature and about 173 MPa (25.1 ksi) at 500°F. Therefore the hoop stress is likely to be above yield even without allowance for corrosion which is not considered. Again dynamic effects are dismissed.

For the Grand Gulf calculation IDCOR refers back to the Peach Bottom discussion. Sequoyah is considered similar to Zion.

Of all three documents, document number 3, the BWROG report, has the most extensive sections dealing with pipe failure. Piping integrity is evaluated using three different criteria:

1) Hoop stress versus burst margins.
2) Limiting axial flaw length in the piping.
3) Pipe rupture probability at a circumferential butt weld.

probabilistic and BWROG cites the probability calculated via the third method as the overall piping failure probability. This approach is inconsistent. The other two criteria should be applied probabilistically also, and all indications are they would produce higher pipe failure probabilities than the third method, which BWROG relies on.

For the first criteria, comparison of pipe hoop stress during overpressurization with burst margin, typical pipes from the Core Spray, RCIC, HPCI and RHR systems are analysed in BWROG. Pipe size ranges from 6 to 24 inch OD. Hoop stresses at 1,050 psi internal pressure are calculated for these various size pipes and compared to a burst hoop stress of 54 ksi which is based on results reported by General Electric from a series of burst tests.[2] All pipes are assumed to be made of A-106 Grade B steel, for which BWROG correctly cites 27 ksi as yield and 60 ksi as ultimate stress at 550°F. An allowance of .08 inches in wall thickness, regardless of diameter, due to corrosion is also made. The hoop stress calculations in BWROG show the following values:

Pipe Size (in.)	Hoop Stress at 1,050 psi (ksi)
6	16.3
14	23.9
16	27.4
20	34.5
24	28.9

Since none of the calculated hoop stresses exceeds 54 ksi, the conclusion in BWROG is that pipe failure will not occur, i.e., has zero probability. This is an inappropriate approach. Both the burst hoop stress and the actual total stress in the pipe should be considered as statistical variables which can take on a range of values. For instance, three of the hoop stresses above are higher than the yield stress of 27 ksi. A probabilistic approach such as that used by Seabrook, discussed earlier, where a hoop stress equal to the yield stress means a .01 failure probability, would imply that the failure probabilities of the 16, 20 and 24 inch pipes are all greater than 0.01!

The application of the second criteria in BWROG, limiting axial flaw length calculated via a limit load approach, suffers from the same inconsistencies as the hoop stress comparison just discussed: A deterministic application of the equations involved reaches the conclusion that the smallest crack length which will lead to failure is 2.4 inches and, since this is too large to remain undetected, failure cannot occur. Without even discussing the question of whether a 2.4 inch flaw will always be detected in time, the approach used can be again termed inconsistent: If the flow stress and hoop stress used in the theory were treated as statistical quantities, a range of crack lengths, some considerably less than 2.4 inches, would result. Failure probabilities associated with the different crack sizes could then be computed.

It is difficult to evaluate the method used in BWROG for obtaining the probability of pipe rupture at a circumferential weld of the piping, i.e., the third criteria used for establishing piping integrity. Since the method involves a complicated computer code, PRAISE, which was not reviewed by us,

essential ingredients of the method remain unknown. A failure probability of 10^{-7} per weld is calculated. When such small probabilities are the result of mathematical models using various assumed inputs to describe a physical process, one wonders to what order of magnitude the result is valid. BWROG assumes 300 welds per piping system and uses the resulting probability of 3×10^{-5} for the weld calculation to represent the total piping failure probability during an interfacing LOCA. This seems a very questionable way to obtain an overall piping failure probability, especially when one remembers that Seabrook assumed a base line failure probability of 10^{-3} due only to manufacturing defects, design errors, construction errors, and other random factors.

To summarize: The Seabrook document has perhaps the most reasonable approach but may still be non-conservative because it neglects corrosion, elevated temperature material effects, and dynamic loading considerations. The IDCOR TR uses only a deterministic comparison in which it grossly overstates yield strengths, neglects corrosion, temperature effects and dynamic consequences. Most of the hoop stresses calculated in the IDCOR TR are actually above the correct yield stresses of the pipe material and so are likely to lead to significant failure probabilities, at least according to the assumptions made by Seabrook. The BWROG document, accounts for corrosion and high temperature but not dynamic loads. It inappropriately uses two deterministic and one probabilistic approach to evaluate different phenomena related to pipe integrity and erroneously concludes that the probabilistic approach used for weld failures gives results which cover all three pipe integrity considerations.

None of the industry reports reviewed above ascribe any importance to the dynamic aspects of the loading on low pressure piping caused by a sudden overpressurization. This neglect of dynamic effects is justified in an appendix of the IDCOR TR and by a related calculation in a PL&G memorandum which show that the maximum pressure in the low pressure pipe cannot exceed the primary system pressure, i.e., no dynamic "pressure spike" is generated which would result in a higher hoop stress than is calculated in a quasi-static manner. The IDCOR and PL&G calculations are reasonable for the assumptions made, namely that the piping system is completely rigid. This may not be true in practice. While no dynamic increases in the local hoop stress may occur, the forces caused by the high pressure wave at elbows and area changes in a flexible piping system can generate bending and torsional moments which add to the total pipe stress. To quote from NUREG-0582, Water Hammer in Nuclear Power Plants; ".... local pressure increase is not the only cause of water hammer damage .... most of the reported damage can be attributed to forces produced during the transient at pipe bends and flow area changes. These forces can cause pipe 'jump' and result in axial forces and bending and torsional moments." While we are not dealing with a classical water hammer problem, the interfacing system LOCA causes a transient to occur, in which a high pressure wave has to travel around elbows and through area changes of a piping system. If the overpressurization is caused by the inadvertent gradual opening of a valve or the slow failure of some valve components the pressure rise will be slow enough so that the problem can be treated quasi-statically. Normal isolation valve opening times on the order of 10's of seconds would allow one to neglect dynamic effects. But if a sudden disintegration of the internals of a valve separating high and low pressure systems occurs, the

dynamic effects on the piping system may be significant.* Exact times for classifying 'fast' versus 'slow' overpressurization depend on the systems involved.

If a sudden overpressurization does occur, the nature and magnitude of the stresses imposed on the pipe due to dynamic effects are dependent on the time history of the force and on the individual piping segment in question. Not only piping material, thickness and diameter but the spatial configuration of the pipe, the location and kind of restraint provided by hangers, equipment attached or suspended from the pipe, location of welds, etc. are all important in determining the response of the piping system to dynamic loading and calculating the resulting forces and moments and corresponding stresses. Obviously no generic calculations are possible and the many piping system and even segment specific calculations needed would be extremely costly, especially since differences in assumptions regarding pressure rise time or hanger idealizations will yield different results. Despite such difficulties, when estimating the pipe break probability, one must keep in mind the possibility of adding significantly to the pipe stress if the overpressurization is fast enough to elicit a dynamic response from the piping system.

BNL Estimate of Pipe Failure Probabilities During Interfacing LOCA

In order to estimate the probability of low pressure piping failure due to overpressurization, we want to incorporate the limited data available, our engineering judgement, and the insights provided by previous work in this area, i.e., the documents just reviewed.

Ideally, every possible mechanism which could lead to pipe failure, would be investigated, modelled, and its contribution to total pipe failure probability assessed. Such a comprehensive analysis is well beyond the scope of our task here. Given the uncertainty associated with our present state of knowledge for many of these mechanisms, the estimate from such a detailed study may be no more precise than that obtained with the more general method we propose here.

Since almost all failure mechanisms are in some way related to pipe stress, we will estimate a failure probability which depends on the maximum stress level in the piping system.

We will avoid a dependence of our estimate on piping length by assuming, similar to the Seabrook approach discussed above, that the estimated probability applies to the particular piping system in question (RCIC, RHR, etc.) as a whole. Stress levels in the piping system depend on the imposed pressure and on the material and geometric properties of the pipe. If a particular piping system contains segments of different properties, we will assume the segment with the highest stress level to be the major contributor to the systems failure probability and use this probability as representative of the overall piping system failure probability.

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*A striking example of such dynamic effects was shown in an Indian Point calculations recently provided to us, but which arrived too late to be included in more detail in this review.

Earlier we discussed the approach used by Seabrook, which assumed a lognormal cumulative failure distribution whose parameters were determined by assigning percentile constraints at σ_y, the yield stress and σ_u, the ultimate stress. Seabrook took these constraints to be $P(\sigma_y) = 0.01$ ($P(\sigma_y)$ represents the cumulative failure probability at the yield stress) and $P(\sigma_u) = 0.99$. The 0.99 value at σ_u seems reasonable since one can expect failure at σ_u with almost certainty. However, assigning a failure probability of 0.01 at the yield stress appears very arbitrary without some supportive data. This arbitrary constraint occurs at the most sensitive part of the probability distribution curve for our calculations: During overpressurization many pipe stresses in BWR low pressure designed systems will be near the yield stress, while in PWRs these systems will experience stresses at or above yield. An assignment of $P(\sigma_y) = 0.001$ for instance, which seems just as defensible (or indefensible) as Seabrook's $P(\sigma_y) = 0.01$ without data, will shift failure probabilities by an order of magnitude on that part of the distribution curve of most interest to us.

By assuming a lognormal distribution with the constraints indicated above, Seabrook has also implicitly assumed that the mean and the median failure stress lie approximately halfway between the yield and ultimate stress. (For Seabrook's lognormal calculations, with $\sigma_y = 35$ ksi and $\sigma_u = 80$ ksi, the mean failure stress is 55.5 ksi and the median 54.6 ksi.) This is not due to the symmetry of the constraints at yield and ultimate, but rather to the nature of the lognormal distribution employed over a relatively narrow variable range between the constraints. For instance, Figure E.1 shows a lognormal distribution for ASTM A106 B constrained by $P(\sigma_y) = 0.001$ and $P(\sigma_u) = 0.99$, where $\sigma_y = 27$ ksi and $\sigma_u = 60$ ksi at 500°F. The mean of this distribution corresponds to 42.1 ksi and the median to 41.7 ksi while $(\sigma_y + \sigma_u)/2$ equals 43.5 ksi. These values of mean and/or median failure stress relative to σ_y and σ_u do not agree with the limited data we do have on pipe overpressurization, i.e., the burst tests conducted by General Electric on ASTM A106 B pipe[2] mentioned in BWROG.

Specifically, General Electric conducted burst tests on seamless A106 B pipes ranging in size from 4-to-12 inches and in diameter to thickness (D/t) ratios from 13.3 to 27.5. A106 B is the material used in BWRs for much of the low pressure piping affected by a postulated interfacing LOCA. During the GE tests the actual yield and ultimate stress of the pipe material used for each test specimen was determined. The average burst hoop stress of unflawed pipe specimens was found to be at approximately 90% of the ultimate stress independent of the pipe size. This indicates that, when constructing a failure probability distribution, the stress corresponding to the distribution mean should be closer to the ultimate stress than the yield stress. Both intuition and theoretical calculations support the concept that the material ultimate stress has a greater influence than the yield stress on the value of the average burst stress. A lognormal distribution determined by specifying the 1st and 99th percentile probability values, as Seabrook has used, is conservative in its estimation of what stress corresponds to the mean failure probability and is not a good choice for the type of "best estimate" we are interested in.

The question of what would constitute a good distribution choice remains. The most defensible distribution is one which reflects only our state of knowledge and no more, i.e., does not add unwarranted assumptions.

Two conclusions which we feel sure enough about to couch as constraints for our distribution are the following:

First, the mean failure stress is approximately at 90% of the ultimate stress. This information is based on tests done on a series of unflawed pipe specimens of A106 B steel.[2] We of course want to include flawed as well as unflawed pipes in our distribution. However, since we expect flawed specimens to be relatively rare, it is reasonable to assume that the first moment of our distribution is similar to the first moment of a distribution for unflawed pipe failures. (Of course, we would expect the variance to be very different for the two distributions.) The other reasonable constraint is to assign the failure probability at the ultimate stress a value close to one: We will use 0.99 as the failure at σ_u.

Therefore, we want to construct a failure probability constrained to have its first moment at 90% of σ_u and its 99th percentile at σ_u. We also will limit the range of the stresses to lie between 1.0 and 100 ksi. We are not interested in negative stresses and an upper limit of 100 ksi at 500°F is quite adequate for the three materials of interest: ASTM A106 B, 304SS, and 316SS. We also assume that the average failure stress will be 0.90 of σ_u for 304 and 316 stainless steel just as it is for ASTM A106 B, even though the test data is only for ASTM A106 B.

The most defensible distribution we can assume is one which reflects the greatest degree of uncertainty given the specified constraints. Assuming any other distribution would mean we have implicitly adopted additional assumptions not supported by the available knowledge. Based on information theory, certain axioms for measuring uncertainty can be established[3] and used to find a maximum uncertainty (sometimes referred to as maximum entropy) distribution. When only the range of a variable is known, a uniform distribution maximizes the entropy. If the range of a variable is unlimited and the first two moments are known, the entropy is maximized by a normal distribution.[4]

For our problem we have a finite variable range and we presume to know the first moment and one percentile constraint. To find the appropriate probability function under these conditions we have used a computer code developed by Unwin,[5] which uses information theory principles to generate that probability distribution over some specified parameter range, given a finite number of constraints, which reflects the maximum degree of uncertainty consistent with those constraints.

Figures E.2, E.3, and E.4 show the cumulative probability functions calculated by the code for the three materials of interest. The ultimate stress values at 500°F for all three steels used to determine the probability curves shown are listed in Table E.1. Yield stresses at 500°F are also shown. A qualitative check on the reasonableness of our distributions can be made by examining the predicted failure probabilities at normal design conditions and at the material yield stress. For 304SS the failure probability at yield shown in Figure E.3 is 2.5×10^{-3}, a factor of four lower than the value at yield assumed by Seabrook to quantify its lognormal distribution even though Seabrook used a room temperature yield of 35 ksi compared to our 24 ksi corresponding to 500°F. The 316SS failure probability

is 2.0×10^{-3} at yield (Figure E.4) while for A106 B failure at yield is up to 8.1×10^{-3} (Figure E.2) - not surprising since A106 B has a considerably lower σ_u than the two stainless steels.

During normal operating conditions these piping systems are stressed in the range of 10 to 15 ksi. As the figures show, failure probabilities here are typically an order of magnitude less than at yield. At 10 ksi 304SS has a cumulative failure probability of 2.3×10^{-4}; for 316SS it is 2.0×10^{-4} and for A106 B the value is 5.4×10^{-4}. These values are all almost an order of magnitude lower than Seabrook's 10^{-3} flat cutoff and appear more appropriate for a best estimate calculation than the conservative higher Seabrook value. In our engineering judgement, the cumulative failure probabilities shown in the figures at both yield and design seem reasonable based on the limited information available.

We believe that Figures E.2, E.3, and E.4 provide reasonable estimates of pipe failure probability vs. pipe stress during an interfacing system LOCA.

If the overpressurization of the piping occurs "slowly" enough so that pipe motion and associated dynamic effects can be neglected, the stress in the pipe can be taken equivalent to the hoop stress due to the internal pressure. Since only the very sudden disintegration of the internals of a valve would lead to "fast" overpressurization, the "slow" situation due to inadvertent openings or gradual failure would appear to be the more usual scenario. If the stress in Figures E.2 through E.4 is only a hoop stress, then it is directly proportional to the diameter to thickness ratio of the pipe, D/t, and to the internal pressure. For a fixed D/t, the abscissa in Figures E.2, E.3, and E.4 can be used to plot internal pressure, or, for a particular pressure, values of D/t can be used on the horizontal axis. Both situations are shown in all the figures.

If dynamic effects and, therefore, bending and shear stresses can be neglected, the figures can be used to relate failure probabilities directly to D/t for a given pressure, or to pressure for a particular D/t. Tables E.2, E.3, and E.4 list the failure probabilities due to hoop stress of a number of typical pipe sizes for expected maximum overpressures as derived from the probability curves in Figures E.2, E.3, and E.4. Table E.2 and Figure E.2 are for BWRs with 106 Grade B carbon steel and 500°F. Tables E.3 and E.4 as well as Figures E.3 and E.4 are for PWRs. Table E.3 and Figure E.3 are for 304 stainless steel at 500°F. Table E.4 and Figure E.4 are for 316 stainless steel at 500°F.

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3. Ash, R., Information Theory, Interscience, 1965.

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5. Unwin, S. D., "IMAGE O: An Information Theory Based Probability Assignment Generator, Brief Code Description and Users Guide," Brookhaven National Laboratory, Technical Report A-3829, 8-28-87.

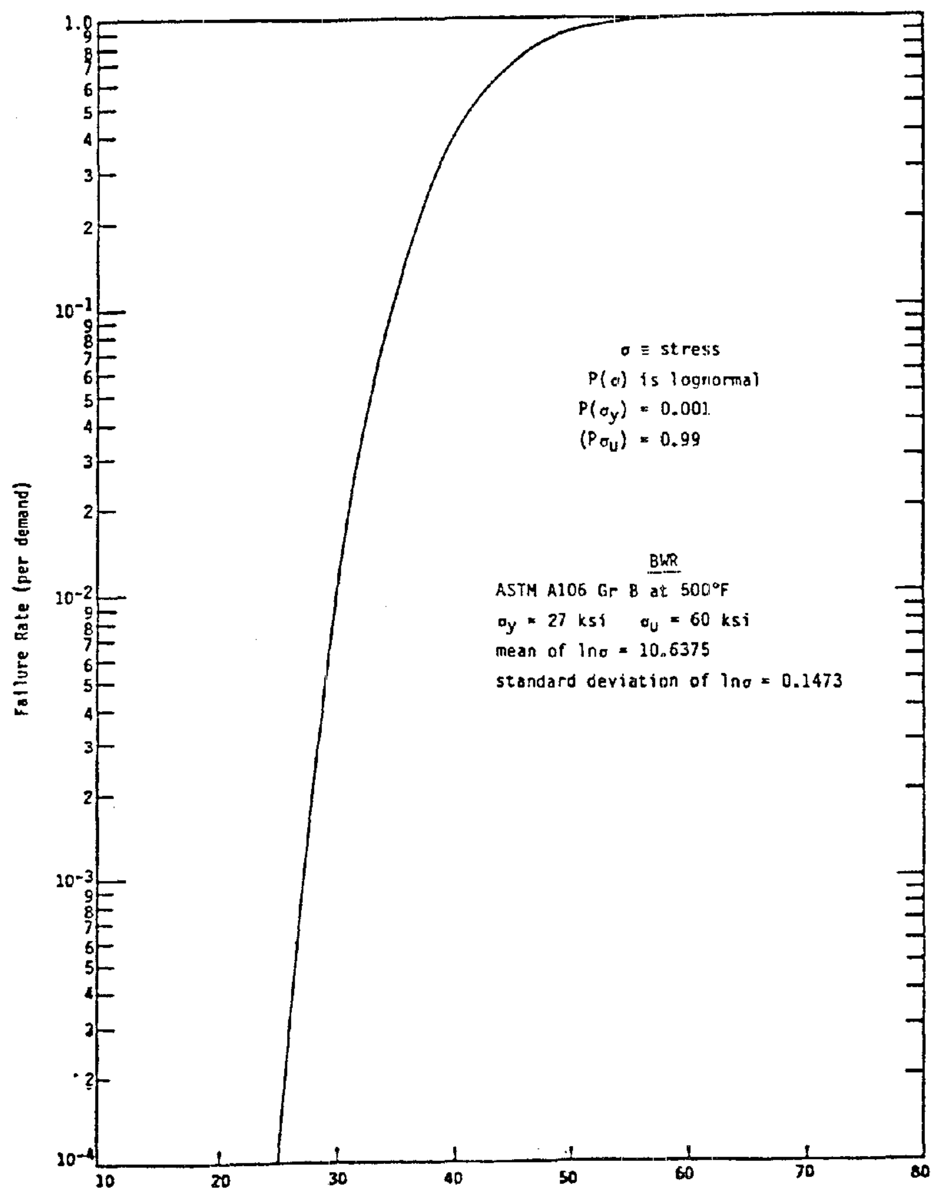

Figure E.1. BWR pipe failure probability - lognormal distribution.

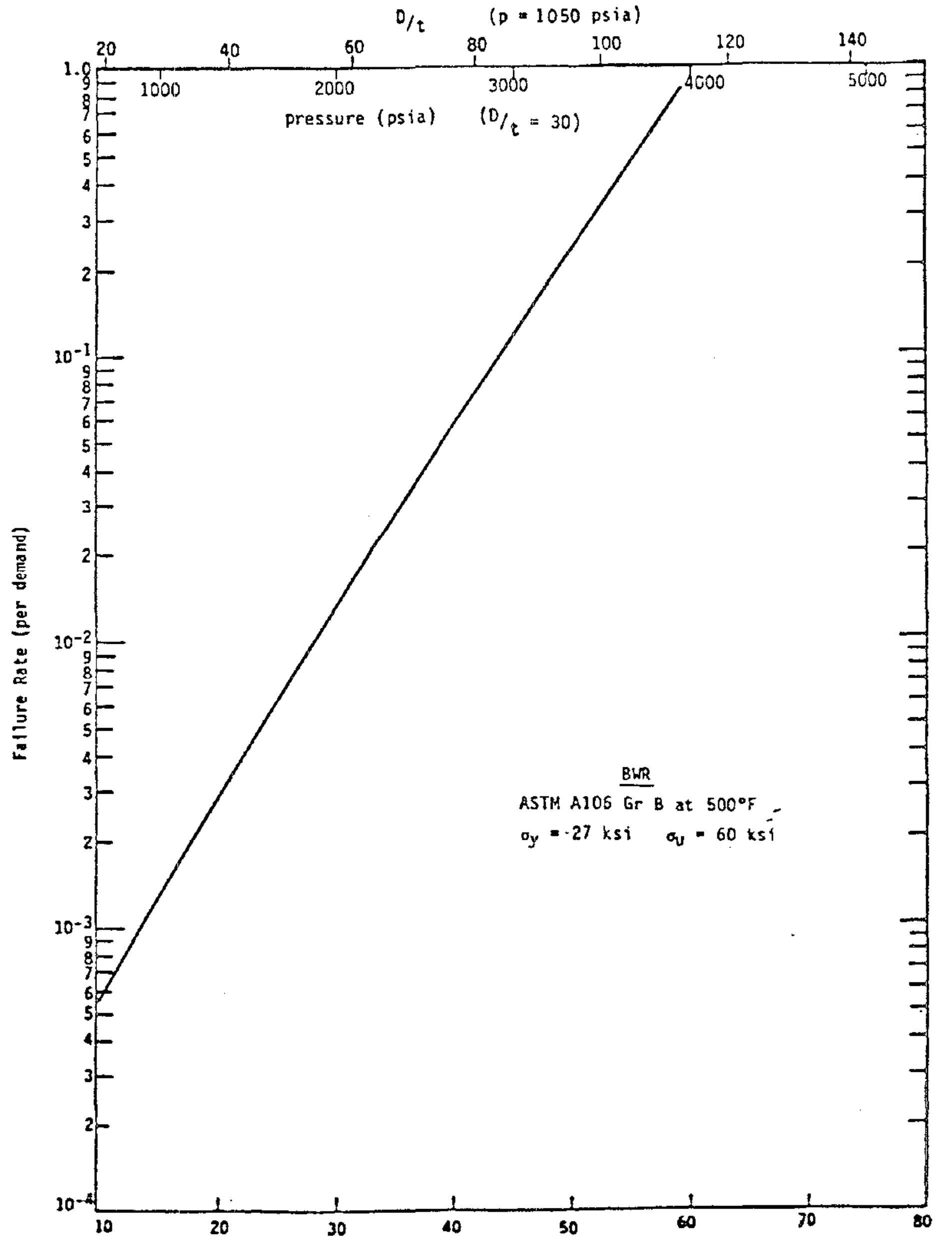

Figure E.2. BWR pipe failure probability - maximum entropy distribution.

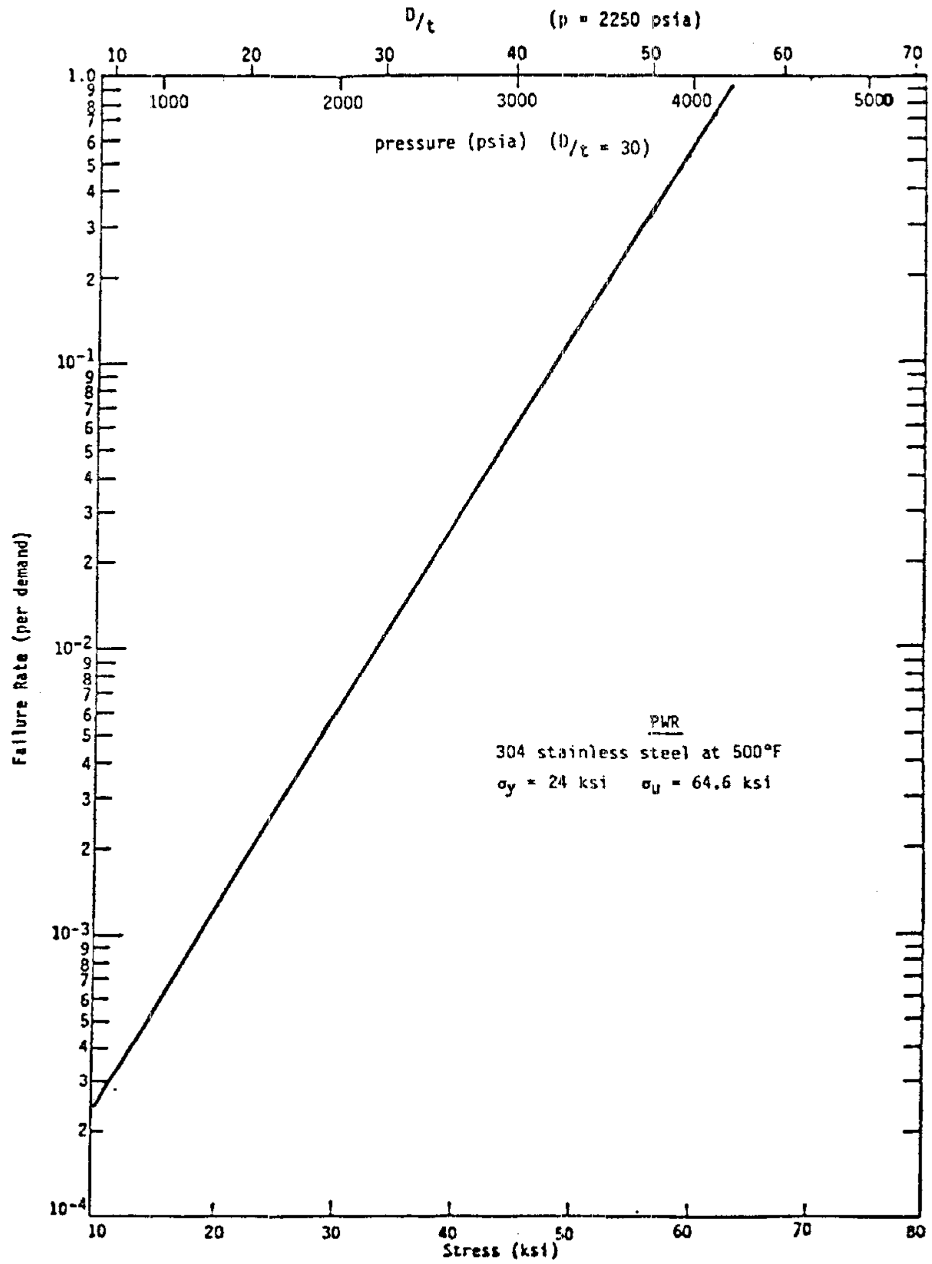

Figure E.3. PWR pipe failure probability - 304SS - maximum entropy distribution.

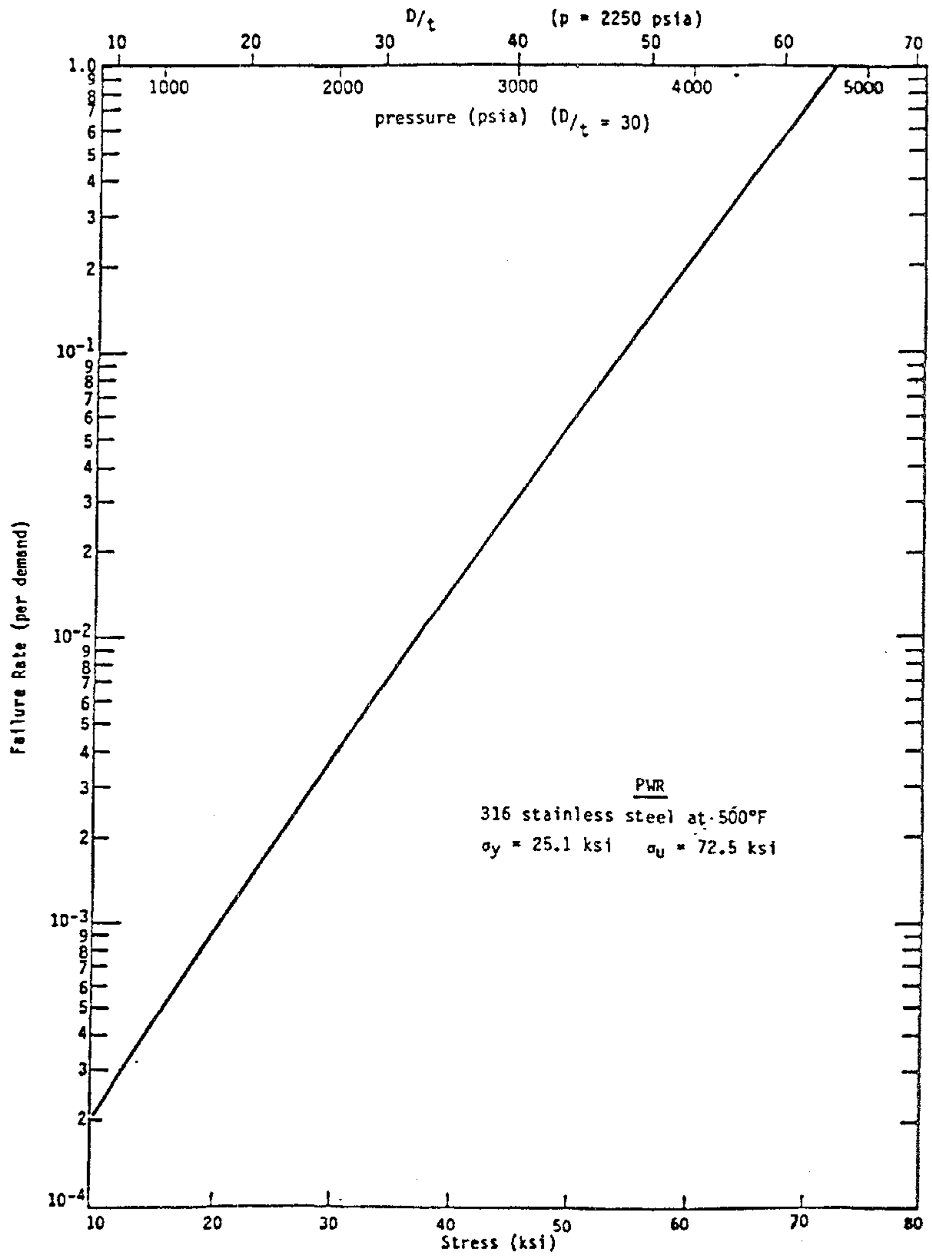

Figure E.4. PWR pipe failure probability - 316SS - maximum entropy distribution.

Table E.1
Steel Properties at 500°F

Steel	Yield Stress ksi	Yield Stress (MPa)	Ultimate Stress ksi	Ultimate Stress (MPa)
A106 GrB Carbon*	27	(186.2)	60	(413.7)
304 Stainless**	24	(165.5)	64.6	(445.4)
316 Stainless**	25.1	(173.1)	72.5	(499.9)

*From BWROG document and Metals Handbook Ninth Edition, AMS, 1978.
**From Reference 1.

Table E. 2
Failure Probabilities for Some BWR Pipes at Maximum Overpressure

Material: A106 GrB Carbon Steel
Properties at 500°F: σ_y = 27 ksi σ_u = 60 ksi
Internal Pressure: 1050 psia

Nominal Pipe Size (in.)	Schedule	As Built D/t	As Built Hoop-stress (ksi)	As Built Failure Probability	Corroded* D/t	Corroded* Hoop-stress (ksi)	Corroded* Failure Probability
3	Std.	15.20	7.98	3.62-4	24.74	12.99	9.23-4
4	Std.	17.99	9.44	4.86-4	27.66	14.52	1.19-3
6	Std.	22.66	11.90	7.63-4	32.13	16.86	1.74-3
8	Std.	25.79	13.54	1.01-3	34.64	18.19	2.14-3
8	XS	16.25	8.53	4.05-4	19.54	10.26	6.07-4
8	--	24.59	12.91	9.10-4	32.56	17.09	1.81-3
10	Std.	28.45	14.94	1.28-3	36.72	19.28	2.54-3
12	Std.	33.00	17.32	1.88-3	42.22	22.16	3.95-3
14	Std.	36.33	19.08	2.46-3	46.46	24.39	5.52-3
16	Std.	41.67	21.88	3.78-3	53.24	27.95	9.34-3
16	XS	31.00	16.28	1.59-3	37.10	19.48	2.63-3
18	Std.	47.00	24.68	5.76-3	60.02	31.51	1.58-2
18	XS	35.00	18.38	2.21-3	41.86	21.98	3.84-3
18	30	40.19	21.10	3.36-3	49.42	25.94	6.94-3
20	Std.	52.33	27.48	8.74-3	66.80	35.07	2.65-2
20	XS	39.00	20.48	3.07-3	46.62	24.48	5.60-3
20	40	32.73	17.18	1.83-3	37.99	19.94	2.81-3
20	60	23.63	12.41	8.36-4	26.32	13.82	1.06-3
24	Std.	63.00	33.08	1.98-2	80.36	42.19	7.48-2
24	XS	47.00	24.68	5.76-3	56.14	29.48	1.17-2
24	60	23.79	12.49	8.48-4	26.03	13.66	1.03-3
30	30	47.00	24.68	5.76-3	54.05	28.37	9.96-3

*All wall thickness reduced by 0.08 inches for corrosion allowance regardless of pipe size.

Table E.3
Failure Probabilities for Some PWR Pipes at Maximum Overpressure

Material: 304 Stainless Steel
Properties at 500°F: σ_y = 24 ksi σ_u = 64.6 ksi
Internal Pressure: 2250 psia

Nominal Pipe Size (in.)	Schedule	As Built D/t	As Built Hoop-stress (ksi)	As Built Failure Probability	Corroded* D/t	Corroded* Hoop-stress (ksi)	Corroded* Failure Probability
2	80S	9.89	11.13	2.93-4	16.21	18.24	9.58-4
2.5	10S	22.96	25.83	3.13-3	70.88	79.73	~1.0
3	80S	10.67	12.00	3.34-4	14.91	16.77	7.54-4
4	80S	12.35	13.90	4.66-4	16.51	18.57	1.01-3
6	40S	22.66	25.49	2.98-3	32.13	36.14	1.50-2
6	80S	14.34	16.13	6.78-4	17.82	20.05	1.27-3
8	40S	25.79	29.01	5.08-3	34.64	38.97	2.29-2
10	20	42.00	47.25	7.99-2	62.24	70.01	~1.0
12	10S	69.83	78.56	~1.0	126.50	142.31	~1.0
12	20	50.00	56.25	3.09-1	74.00	83.25	~1.0
14	10	55.00	61.88	7.21-1	81.35	91.52	~1.0
14	30	36.33	40.88	3.07-2	46.46	52.26	1.70-1
14	40	31.04	34.92	1.24-2	38.22	42.99	4.21-2
14	140	10.20	11.48	3.05-4	10.97	12.34	3.56-4

*All wall thickness reduced by 0.08 inches for corrosion allowance regardless of pipe size.

Table E.4
Failure Probabilities for Some PWR Pipes at Maximum Overpressure

Material: 316 Stainless Steel
Properties at 500°F: σ_y = 25.1 ksi σ_u = 72.5 ksi
Internal Pressure: 2250 psia

Nominal Pipe Size (in.)	Schedule	As Built D/t	As Built Hoop-stress (ksi)	As Built Failure Proba-bility	Corroded* D/t	Corroded* Hoop-stress (ksi)	Corroded* Failure Proba-bility
2	80S	9.89	11.13	2.49-4	16.21	18.24	7.52-4
2.5	10S	22.96	25.83	1.90-3	70.88	79.73	~1.0
3	80S	10.67	12.00	2.88-4	14.91	16.77	6.06-4
4	80S	12.35	13.90	3.91-4	16.51	18.57	7.89-4
6	40S	22.66	25.49	2.08-3	32.13	36.14	8.68-3
6	80S	14.34	16.13	5.51-4	17.82	20.05	9.73-4
8	40S	25.79	29.01	3.34-3	34.64	38.97	1.26-2
10	20	42.00	47.25	3.78-2	62.24	70.01	7.60-1
12	10S	69.83	78.56	~1.0	126.50	142.31	~1.0
12	20	50.00	56.25	1.24-1	74.00	83.25	~1.0
14	10	55.00	61.88	2.61-1	81.35	91.52	~1.0
14	30	36.33	40.88	1.63-2	46.46	52.26	7.33-2
14	40	31.04	34.92	7.38-3	38.22	42.99	2.15-2
14	140	10.20	11.48	2.65-4	10.97	12.34	3.05-4

*All wall thickness reduced by 0.08 inches for corrosion allowance regardless of pipe size.

APPENDIX F: Sensitivity Calculations

In this appendix, the results of some sensitivity calculations on pipe rupture probability and common mode failure are presented. They are shown in Tables F.1 to F.17.

1. Pipe Rupture Probability - Three values for conditional probability of rupture were used in the calculations, i.e., 10^{-1}, 10^{-3}, and 3.0×10^{-5}.

2. Common Mode Failure - The survey of operating experience discussed in Section 3 did not identify any evidence of common mode failures of pressure isolation valves besides the feedwater check valve failures at San Onofre-1. As a sensitivity study, common mode failure was considered where two identical valves are in series by assuming that the beta factor may take on three possible values, 0, 0.05, and 0.1. When the beta factor is equal to zero, it represents the case that the failures are independent. The value of 0.1 was chosen because it is typically used for screening purposes. The following lines contain two identical valves in series:

   - RHR Suction Lines - Common mode failure is considered for the rupture failure mode.
   - Steam Condensing Lines of Nine Mile Point-2 - Common mode failure is considered for the rupture failure mode.
   - Vessel Head Spray for Nine Mile Point-2 - Common mode failure is considered for the failure mode of rusted linkage of the air-operated check valves.

Table F.1
Summary of Results - Sensitivity

Plant	Beta	f(OP)	P(Rupture)	S2	A	CDF
Peach Bottom	0.0	9.23E-03	1.00E-01	3.11E-05	1.05E-04	5.59E-06
			1.00E-03	3.12E-05	1.05E-06	1.99E-07
			3.00E-05	3.12E-05	3.16E-08	1.46E-07
	0.05	9.29E-03	1.00E-01	8.51E-05	1.11E-04	1.18E-05
			1.00E-03	9.11E-05	1.11E-06	5.37E-07
			3.00E-05	9.12E-05	3.34E-08	4.27E-07
	0.1	9.35E-03	1.00E-01	1.39E-04	1.17E-04	1.81E-05
			1.00E-03	1.51E-04	1.17E-06	8.75E-07
			3.00E-05	1.51E-04	3.52E-08	7.07E-07
Nine Mile Point-2	0.0	9.92E-03	1.00E-01	6.99E-04	3.23E-04	2.23E-04
			1.00E-03	4.10E-05	3.23E-06	2.23E-06
			3.00E-05	3.46E-05	9.68E-08	7.13E-08
	0.05	1.05E-02	1.00E-01	7.90E-04	3.41E-04	2.41E-04
			1.00E-03	1.03E-04	3.41E-06	2.42E-06
			3.00E-05	9.58E-05	1.02E-07	8.42E-08
	0.1	1.10E-02	1.00E-01	8.81E-04	3.59E-04	2.59E-04
			1.00E-03	1.64E-04	3.59E-06	2.61E-06
			3.00E-05	1.57E-04	1.08E-07	9.72E-08
Quad Cities	0.0	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
	0.05	6.95E-03	1.00E-01	9.55E-05	1.15E-04	1.59E-05
			1.00E-03	1.02E-04	1.15E-06	6.98E-07
			3.00E-05	1.02E-04	3.46E-08	5.49E-07
	0.1	7.01E-03	1.00E-01	1.50E-04	1.21E-04	2.22E-05
			1.00E-03	1.62E-04	1.21E-06	1.08E-06
			3.00E-05	1.62E-04	3.64E-08	8.73E-07

Notes: Beta = Beta Factor for Common Cause Failure.
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 F.2
Summary of Results for Peach Bottom - Sensitivity

Line	Beta	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		2.59E-03	1.00E-01	0.00E+00	2.82E-07	2.82E-07
			1.00E-03	0.00E+00	2.82E-09	2.82E-09
			3.00E-05	0.00E+00	8.47E-11	8.47E-11
RCIC		2.59E-03	1.00E-01	0.00E+00	2.82E-07	2.82E-07
			1.00E-03	0.00E+00	2.82E-09	2.82E-09
			3.00E-05	0.00E+00	8.47E-11	8.47E-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	0.0	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
	0.05	6.08E-05	1.00E-01	5.47E-05	6.03E-06	6.28E-06
			1.00E-03	6.07E-05	6.03E-08	3.42E-07
			3.00E-05	6.08E-05	1.81E-09	2.84E-07
	0.1	1.21E-04	1.00E-01	1.09E-04	1.20E-05	1.25E-05
			1.00E-03	1.21E-04	1.20E-07	6.80E-07
			3.00E-05	1.21E-04	3.61E-09	5.64E-07
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 F.3
Summary Calculations for LPCI of Peach Bottom - Sensitivity

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
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

Table F.3 (Continued)

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
		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 Incidents (Leakage)	2.94E-03	1.93E-06	5.66E-09	0.00E+00	5.66E-11	0.00E+00
		Failure to Reclose		0.00E+00	5.66E-11	0.00E+00
				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: AOV = Failure Rate of Air-Operated Check Valve (/ry).
MOV = Probability of MOV Failure.
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).

Table F.4
Summary Calculations for CS of Peach Bottom - Sensitivity

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
				1.00E-03	7.35E-06	7.35E-09
				3.00E-05	7.35E-06	2.20E-10
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
		Rupture	4.41E-07	1.00E-01	4.40E-09	4.41E-10
		6.00E-04		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
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

Table F.4 (Continued)

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
		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: AOV = Failure Rate of Air-Operated Check Valve (/ry).
MOV = Probability of MOV Failure.
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).

Table F.5
Summary of Calculations for HPCI of Peach Bottom - Sensitivity

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
		6.00E-03	8.82E-05	1.00E-01	0.00E+00	8.82E-09
		Inadvertent Opening		1.00E-03	0.00E+00	8.82E-11
				3.00E-05	0.00E+00	2.65E-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			7.35E-04	1.00E-01	0.00E+00	7.35E-08
(Reverse Air, Inadvertent Opened)				1.00E-03	0.00E+00	7.35E-10
				3.00E-05	0.00E+00	2.20E-11
Cooper	7.35E-03	1.20E-03	8.82E-06	1.00E-01	0.00E+00	8.82E-09
(Foreign Material)		Rupture		1.00E-03	0.00E+00	8.82E-11
				3.00E-05	0.00E+00	2.65E-12
		6.00E-03	4.41E-05	1.00E-01	0.00E+00	4.41E-08
		Inadvertent Opening		1.00E-03	0.00E+00	4.41E-10
				3.00E-05	0.00E+00	1.32E-11
		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
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
		6.00E-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	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
		6.00E-03	4.41E-05	1.00E-01	0.00E+00	4.41E-08
		Inadvertent Opening		1.00E-03	0.00E+00	4.41E-10
				3.00E-05	0.00E+00	1.32E-11
		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

See Note 3.

Table F.6
Summary of Calculations for RCIC of Peach Bottom - Sensitivity

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
		6.00E-03	8.82E-05	1.00E-01	0.00E+00	8.82E-09
		Inadvertent Opening		1.00E-03	0.00E+00	8.82E-11
				3.00E-05	0.00E+00	2.65E-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			7.35E-04	1.00E-01	0.00E+00	7.35E-08
(Reverse Air, Inadvertent Opened)				1.00E-03	0.00E+00	7.35E-10
				3.00E-05	0.00E+00	2.20E-11
Cooper	7.35E-03	1.20E-03	8.82E-06	1.00E-01	0.00E+00	8.82E-09
(Foreign Material)		Rupture		1.00E-03	0.00E+00	8.82E-11
				3.00E-05	0.00E+00	2.65E-12
		6.00E-03	4.41E-05	1.00E-01	0.00E+00	4.41E-08
		Inadvertent Opening		1.00E-03	0.00E+00	4.41E-10
				3.00E-05	0.00E+00	1.32E-11
		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
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
		6.00E-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	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
				3.00E-05	0.00E+00	2.65E-12
		6.00E-03	4.41E-05	1.00E-01	0.00E+00	4.41E-08
		Inadvertent Opening		1.00E-03	0.00E+00	4.41E-10
				3.00E-05	0.00E+00	1.32E-11
		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

See Note 3.

Table F.7
Summary of Results for Nine Mile Point-2 - Sensitivity

Line	Beta	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	0.0	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
	0.05	2.28E-05	1.00E-01	2.64E-07	1.89E-09	3.05E-09
			1.00E-03	2.64E-07	1.89E-11	1.17E-09
			3.00E-05	2.64E-07	5.68E-13	1.15E-09
	0.1	4.12E-05	1.00E-01	4.78E-07	3.73E-09	5.82E-09
			1.00E-03	4.78E-07	3.73E-11	2.12E-09
			3.00E-05	4.78E-07	1.12E-12	2.09E-09
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	0.0	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
	0.05	6.08E-05	1.00E-01	5.47E-05	6.03E-06	6.03E-06
			1.00E-03	6.07E-05	6.03E-08	6.68E-08
			3.00E-05	6.08E-05	1.81E-09	8.37E-09
	0.1	1.21E-04	1.00E-01	1.09E-04	1.20E-05	1.20E-05
			1.00E-03	1.21E-04	1.20E-07	1.33E-07
			3.00E-05	1.21E-04	3.61E-09	1.67E-08
Steam Condensing	0.0	8.89E-03	1.00E-01	6.83E-04	2.22E-04	2.22E-04
			1.00E-03	2.44E-05	2.22E-06	2.23E-06
			3.00E-05	1.80E-05	6.67E-08	6.86E-08
	0.05	9.37E-03	1.00E-01	7.20E-04	2.34E-04	2.34E-04
			1.00E-03	2.58E-05	2.34E-06	2.35E-06
			3.00E-05	1.90E-05	7.03E-08	7.23E-08
	0.1	9.85E-03	1.00E-01	7.57E-04	2.46E-04	2.46E-04
			1.00E-03	2.71E-05	2.46E-06	2.47E-06
			3.00E-05	1.99E-05	7.39E-08	7.60E-08

See Note 4.

Table F.8
Summary Calculations for LPCI of Nine Mile Point-2 - Sensitivity

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 (Leakage)	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: AOV = Failure Rate of Air-Operated Check Valve (/ry).
MOV = Probability of MOV Failure.
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).

Table F.9
Summary Calculations for LPCS of Nine Mile Point-2 - Sensitivity

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Pilgrim-1	7.35E-04	6.00E-04	4.41E-07	1.00E-01	4.40E-07	4.41E-10
Sept. 29,1983		Rupture		1.00E-03	4.41E-07	4.41E-12
				3.00E-05	4.41E-07	1.32E-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
Four Remaining	2.94E-03	6.00E-04	1.76E-06	0.00E+00	1.76E-06	0.00E+00
Incidents		Rupture		0.00E+00	1.76E-06	0.00E+00
(Leakage)				0.00E+00	1.76E-06	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: AOV = Failure Rate of Air-Operated Check Valve (/ry).
MOV = Probability of MOV Failure.
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).

Table F.10
Summary Calculations for HPCS of Nine Mile Point-2 - Sensitivity

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
(Leakage)		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: AOV = Failure Rate of Air-Operated Check Valve (/ry).
MOV = Probability of MOV Failure.
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).

Table F.11
Summary of Calculations for Vessel Head Spray of Nine Mile Point-2

Experience	Beta	AOV	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		0.00E+00	1.63E-09	0.00E+00
Rusted Linkage+Leak		1.08E-06	to 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	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
			Open 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		0.00E+00	3.08E-11	0.00E+00
			Open		0.00E+00	3.08E-11	0.00E+00
Rusted	0.0	1.06E-06	2.14E-04	2.28E-10	0.00E+00	2.28E-10	0.00E+00
Linkage (both)			Failure		0.00E+00	2.28E-10	0.00E+00
			to 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
			Open 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		1.00E-03	4.31E-12	4.31E-16
			Open		3.00E-05	4.31E-12	1.29E-17
	0.05	3.78E-05	2.14E-04	8.09E-09	0.00E+00	8.09E-09	0.00E+00
			Failure		0.00E+00	8.09E-09	0.00E+00
			to Reclose		0.00E+00	8.09E-09	0.00E+00
			6.00E-04	2.27E-08	1.00E-01	2.27E-08	2.27E-12
			Rupture		1.00E-03	2.27E-08	2.27E-14
					3.00E-05	2.27E-08	6.80E-16
			5.00E-01	1.89E-05	1.00E-01	1.89E-07	1.89E-09
			Open in Test		1.00E-03	1.89E-07	1.89E-11
					3.00E-05	1.89E-07	5.67E-13
			4.05E-04	1.53E-08	1.00E-01	1.53E-10	1.53E-12
			Transfer Open		1.00E-03	1.53E-10	1.53E-14
					3.00E-05	1.53E-10	4.59E-16
	0.1	7.45E-05	2.14E-04	1.60E-08	0.00E+00	1.60E-08	0.00E+00
			Failure		0.00E+00	1.60E-08	0.00E+00
			to Reclose		0.00E+00	1.60E-08	0.00E+00
			6.00E-04	4.47E-08	1.00E-01	4.47E-08	4.47E-12
			Rupture		1.00E-03	4.47E-08	4.47E-14
					3.00E-05	4.47E-08	1.34E-15
			5.00E-01	3.73E-05	1.00E-01	3.73E-07	3.73E-09
			Open in Test		1.00E-03	3.73E-07	3.73E-11
					3.00E-05	3.73E-07	1.12E-12

Table F.11 (Continued)

Experience	Beta	AOV	MOV	f(OP)	P(Rupture)	S2	A
			4.05E-04	3.02E-08	1.00E-01	3.02E-10	3.02E-12
			Transfer Open		1.00E-03	3.02E-10	3.02E-14
					3.00E-05	3.02E-10	9.06E-16

Notes: Beta = Beta Factor for Common Cause Failure.
AOV = Failure Rate of Air-Operated Check Valve (/ry).
MOV = Probability of MOV Failure.
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).

Table F.12
Summary Calculations for Steam Condensing Lines of Nine Mile Point-2 - Sensitivity

Pair	Beta	MOV1	MOV2	f(OP)	P(Rupture)	S2	A
F052&F087		4.00E+00	2.28E-08	9.13E-08	1.00E-01	4.73E-09	4.57E-09
		Cycling	Rupture		1.00E-03	2.28E-10	4.57E-11
		per ry			3.00E-05	1.84E-10	1.37E-12
			2.02E-04	8.10E-04	1.00E-01	4.20E-05	4.05E-05
			Transfer		1.00E-03	2.02E-06	4.05E-07
			Open		3.00E-05	1.63E-06	1.21E-08
	0.0	1.20E-03	1.50E-04	2.58E-07	1.00E-01	1.33E-08	1.29E-08
		Rupture	Rupture		1.00E-03	6.43E-10	1.29E-10
					3.00E-05	5.19E-10	3.86E-12
	5.00E-02			6.03E-05	1.00E-01	3.12E-06	3.01E-06
					1.00E-03	1.51E-07	3.01E-08
					3.00E-05	1.21E-07	9.04E-10
	1.00E-01			1.20E-04	1.00E-01	6.23E-06	6.01E-06
					1.00E-03	3.00E-07	6.01E-08
					3.00E-05	2.42E-07	1.80E-09
			5.00E-01	6.00E-04	1.00E-01	3.11E-05	3.00E-05
			Interlock		1.00E-03	1.50E-06	3.00E-07
			Calibration		3.00E-05	1.21E-06	9.00E-09
			8.10E-04	9.72E-07	1.00E-01	5.03E-08	4.86E-08
			Transfer		1.00E-03	2.43E-09	4.86E-10
			Open		3.00E-05	1.96E-09	1.46E-11
F218&F087		4.00E+00	2.28E-08	9.13E-08	1.00E-01	9.30E-09	0.00E+00
		Cycling	Rupture		1.00E-03	2.74E-10	0.00E+00
		per ry			3.00E-05	1.85E-10	0.00E+00
			2.02E-04	8.10E-04	1.00E-01	8.25E-05	0.00E+00
			Transfer		1.00E-03	2.43E-06	0.00E+00
			Open		3.00E-05	1.64E-06	0.00E+00
	0.0	1.20E-03	1.50E-04	2.58E-07	1.00E-01	2.62E-08	0.00E+00
		Rupture	Rupture		1.00E-03	7.72E-10	0.00E+00
					3.00E-05	5.23E-10	0.00E+00
	5.00E-02			6.03E-05	1.00E-01	6.13E-06	0.00E+00
					1.00E-03	1.81E-07	0.00E+00
					3.00E-05	1.22E-07	0.00E+00
	1.00E-01			1.20E-04	1.00E-01	1.22E-05	0.00E+00
					1.00E-03	3.61E-07	0.00E+00
					3.00E-05	2.44E-07	0.00E+00
			5.00E-01	6.00E-04	1.00E-01	6.11E-05	0.00E+00
			Interlock		1.00E-03	1.80E-06	0.00E+00
			Calibration		3.00E-05	1.22E-06	0.00E+00
			8.10E-04	9.72E-07	1.00E-01	9.89E-08	0.00E+00
			Transfer		1.00E-03	2.91E-09	0.00E+00
			Open		3.00E-05	1.97E-09	0.00E+00

Table F.12 (Continued)

Pair	Beta	MOV1	MOV2	f(OP)	P(Rupture)	S2	A
F052&F051		4.00E+00 Cycling per ry	2.28E-08 Rupture	9.13E-08	1.00E-01	4.73E-09	4.57E-09
					1.00E-03	2.28E-10	4.57E-11
					3.00E-05	1.84E-10	1.37E-12
			2.02E-04 Transfer Open	8.10E-04	1.00E-01	4.20E-05	4.05E-05
					1.00E-03	2.02E-06	4.05E-07
					3.00E-05	1.63E-06	1.21E-08
	0.0	1.20E-03 Rupture	1.50E-04 Rupture	2.58E-07	1.00E-01	1.33E-08	1.29E-08
					1.00E-03	6.43E-10	1.29E-10
					3.00E-05	5.19E-10	3.86E-12
	5.00E-02			6.03E-05	1.00E-01	3.12E-06	3.01E-06
					1.00E-03	1.51E-07	3.01E-08
					3.00E-05	1.21E-07	9.04E-10
	1.00E-01			1.20E-04	1.00E-01	6.23E-06	6.01E-06
					1.00E-03	3.00E-07	6.01E-08
					3.00E-05	2.42E-07	1.80E-09
			8.10E-04 Transfer Open	9.72E-07	1.00E-01	5.03E-08	4.86E-08
					1.00E-03	2.43E-09	4.86E-10
					3.00E-05	1.96E-09	1.46E-11
F218&F051		4.00E+00 Cycling per ry	2.28E-08 Rupture	9.13E-08	1.00E-01	9.30E-09	0.00E+00
					1.00E-03	2.74E-10	0.00E+00
					3.00E-05	1.85E-10	0.00E+00
			2.02E-04 Transfer Open	8.10E-04	1.00E-01	8.25E-05	0.00E+00
					1.00E-03	2.43E-06	0.00E+00
					3.00E-05	1.64E-06	0.00E+00
	0.0	1.20E-03 Rupture	1.50E-04 Rupture	2.58E-07	1.00E-01	2.62E-08	0.00E+00
					1.00E-03	7.72E-10	0.00E+00
					3.00E-05	5.23E-10	0.00E+00
	5.00E-02			6.03E-05	1.00E-01	6.13E-06	0.00E+00
					1.00E-03	1.81E-07	0.00E+00
					3.00E-05	1.22E-07	0.00E+00
	1.00E-01			1.20E-04	1.00E-01	1.22E-05	0.00E+00
					1.00E-03	3.61E-07	0.00E+00
					3.00E-05	2.44E-07	0.00E+00
			8.10E-04 Transfer Open	9.72E-07	1.00E-01	9.89E-08	0.00E+00
					1.00E-03	2.91E-09	0.00E+00
					3.00E-05	1.97E-09	0.00E+00

Notes: Beta = Beta Factor for Common Cause Failure.
AOV = Failure Rate of Air-Operated Check Valve (/ry).
MOV = Probability of MOV Failure.
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).

Table F.13
Summary of Results for Quad Cities - Sensitivity

Line	Beta	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	0.0	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
	0.05	6.08E-05	1.00E-01	5.47E-05	6.03E-06	6.32E-06
			1.00E-03	6.07E-05	6.03E-08	3.86E-07
			3.00E-05	6.08E-05	1.81E-09	3.28E-07
	0.1	1.21E-04	1.00E-01	1.09E-04	1.20E-05	1.26E-05
			1.00E-03	1.21E-04	1.20E-07	7.67E-07
			3.00E-05	1.21E-04	3.61E-09	6.51E-07
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: Beta = Beta Factor for Common Cause Failure.
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 F.14
Summary Calculations for LPCI of Quad Cities - Sensitivity

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		0.00E+00	3.77E-07	0.00E+00
(Reverse Air)		to 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		0.00E+00	1.89E-07	0.00E+00
		to 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		0.00E+00	1.89E-07	0.00E+00
(Rusted Linkage)		to 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		0.00E+00	1.89E-07	0.00E+00
(Misalignment of Gears)		to 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
Four Remaining	2.94E-02	2.57E-03	7.55E-05	0.00E+00	7.55E-07	0.00E+00
Incidents		Failure		0.00E+00	7.55E-07	0.00E+00
(Leak)		to 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

Table F.14 (Continued)

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Vermont Yankee			7.35E-04	0.00E+00	7.35E-06	0.00E+00
Scenario				0.00E+00	7.35E-06	0.00E+00
(Leak, Failure to Fully Close)				0.00E+00	7.35E-06	0.00E+00

Notes: AOV = Failure Rate of Air-Operated Check Valve (/ry).
MOV = Probability of MOV Failure.
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).

Table F.15
Summary Calculations for CS 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		0.00E+00	3.77E-07	0.00E+00
(Reverse Air)		to 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
Pilgrim-1	7.35E-03	2.57E-03	1.89E-05	0.00E+00	1.89E-07	0.00E+00
Sept. 29,1983		Failure		0.00E+00	1.89E-07	0.00E+00
(Rusted Linkage)		to 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		0.00E+00	1.89E-07	0.00E+00
(Misalignment of Gears)		to 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
Four Remaining	2.94E-02	2.57E-03	7.55E-05	0.00E+00	7.55E-07	0.00E+00
Incidents		Failure		0.00E+00	7.55E-07	0.00E+00
(Leak)		to 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			7.35E-04	0.00E+00	7.35E-06	0.00E+00
Scenario				0.00E+00	7.35E-06	0.00E+00
(Leak, Failure to Fully Close)				0.00E+00	7.35E-06	0.00E+00

See Note 3.

Table F.16
Summary of Calculations for HPCI of Quad Cities - Sensitivity

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: AOV = Failure Rate of Air-Operated Check Valve (/ry).
MOV = Probability of MOV Failure.
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).

Table F.17
Summary of Calculations for RCIC of Quad Cities - Sensitivity

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: AOV = Failure Rate of Air-Operated Check Valve (/ry).
MOV = Probability of MOV Failure.
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).

Notes for Appendix F Tables

Note 1: f(OP) = Frequency of Overpressurization (/ry).
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
CDF = Core Damage Frequency (/ry).

Note 2: 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).

Note 3: AOV = Failure Rate of Air-Operated Check Vale (/ry).
MOV = Probability of MOV Failure.
f(OP) = Frequency of Overpressurization (/ry).
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).

Note 4: Beta = Beta Factor for Common Cause Failure.
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).

Note 5: Beta = Beta Factor for Common Cause Failure.
AOV = Failure Rate of Air-Operated Check Vale (/ry).
MOV = Probability of MOV Failure.
f(OP) = Frequency of Overpressurization (/ry).
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).

APPENDIX G: Cost Estimates Provided by the Plants

G.1 Cost Estimates Provided by Peach Bottom

ATTACHMENT A

Cost and Dose Estimates

A. Paragraph 5.1.1 Leak Test After Maintenance

A.1 The following is a list of Air Operated Testable Check Valves. Considering both Preventive and Corrective Maintenance, each valve would be maintained once each 24 months average.

PERFORMING LEAK TEST POST MAINTENANCE

System/Valve	Man-Hours	Man-Rem
HPCI AO-23-18	28	0.25
RCIC AO-13-22	28	0.25
RHR AO-10-46A	30	0.4
RHR AO-10-46B	30	0.4
Core Spray AO-14-13A	25	0.375
Core Spray AO-14-13B	25	0.375
Total for One Unit for Two Years	166	2.05

A.2 In addition, because the Core Spray and RHR must be tested to comply with 10CFR 50 Appendix J, these test procedures have already been written. To write, review, approve, type, duplicate, and distribute new test procedures for HPCI and RCIC, it is estimated 480 man-hours would be required.

A.3 The RHR and Core Spray Leak Tests will be performed each fuel cycle as required by Appendix J.

PERFORMING LEAK TEST FOR APPENDIX J

System/Valve	Man-Hours	Man-Rem
RHR AO-10-46A	30	0.4
RHR AO-10-46B	30	0.4
Core Spray AO-14-13A	25	0.375
Core Spray AO-14-13B	25	0.375
Total for One Unit for each 18 Month Fuel Cycle	110	1.55

A.4 The fuel cycle Appendix J test and the post maintenance test will not coincide. The Appendix J test is performed immediately after shutdown to obtain "As Found" data. If the leakage is too high, or if preventive or other corrective maintenance is performed, the test must be repeated as a post maintenance test. Therefore, the costs are additive.

B. Paragraph 5.1.2 Perform Logic System Functional Tests of ECCS

B.1 The purpose of the Logic System Functional Test is as follows:

> The purpose of this test is to ascertain the ability of the HPCI SYSTEM LOGIC to initiate and sustain the automatic operation of the HPCI SYSTEM during design accident conditions.

The design accident conditions are full power normal operating conditions. Performing the test at shutdown does not really meet that condition.

B.2 The HPCI and RCIC Systems, being steam driven systems require reactor steam. Auxiliary boilers steam is not capable of achieving rated HPCI flow at rated pressure. For the HPCI test, power levels above 9% are required.

B.3 The logic systems are required by 10CFR to be testable. The "testability" features included in the logic systems are designed to allow testing at normal operating conditions.

B.4 If the test frequency were changed from "once per 6 months" to "once per operating cycle", the risk could be redued by a factor of 3 to 4. But testing with reactor steam is still required for HPCI and RCIC.

B.5 The Core Spray and RHR systems may be able to be tested during shutdown conditions because they are low pressure systems.

B.6 The cost estimate for writing, reviewing, approving, typing, duplication, and distribution is as follows:

PROCEDURE REVISION FOR LOGIC SYSTEM TESTS

System	Man-Hours
Core Spray A Logic	480
Core Spray B Logic	480
RHR A Logic	480
RHR B Logic	480
Total for One Unit	1920

B.7 Because of the system "testability" design additional man power will be required to perform the tests.

System/Valve	Man-Hours	Man-Rem
Core Spray A	8	0.12
Core Spray B	8	0.12
RHR A	8	0.12
RHR B	8	0.12
Total for One Unit	32	0.48

B.8 Cost to process Tech Spec change of test frequency.

BWROG performing safty analysis

1. PECo's share of BWROG cost: $8,000

2. NRC fee to process Tech Spec: $5,000

3. PECo's time to process Tech Spec Amend

	Man-Hours
Licensing Section Engineer (Draft - Coordinate)	40
Review by Management, Safety Committees, Legal	40
Typing	10
Resolve NRC Questions	40
	130 Hours

Based on $40/hr yields approximately $5,000

Total Cost: 8,000 + 5,000 + 5,000 = $18,000

C. Paragraph 5.1.3 Leak Test HPCI & RCIC Testable Check Valves Every Refueling

C.1 To leak test HPCI and RCIC each refueling.

PERFORMING LEAK TEST EACH REFUELING

System/Valve	Man-Hours	Man-Rem
HPCI AO-23-18	28	0.25
RCIC AO-13-22	28	0.25
Total per Unit for each 18 month cycle	56	0.5

C.2 Using historical data on other tested check valves, they will fail the leak test and require maintenance and post maintenance retesting 25% of the time. Therefore, these values must be increased by 25%.

	Man-Hours	Man-Rem
Times 1.25	70	0.625

C.3 The estimate for procedure writing for this item are in paragraph A.2.

G.2 Cost Estimates Provided by Nine Mile Point-2

NIAGARA MOHAWK

NINE MILE POINT—UNIT 2/P.O. BOX 63, LYCOMING, NY 13093/TELEPHONE (315) 343-2110

January 21, 1987

Mr. T.L. Chu
Risk Evaluation Group
Brookhaven National Lab
Upton, Long Island, New York 11973

Dear Mr. Chu;

In response to your letter of 12/22/86 and our subsequent conversation, we have attempted to make an estimate of the total cost of obtaining relief of the referenced ISI requirements.

These ISI requirements had already been identified in a current program revision to be changed, so a specific cost estimate is not easily obtainable. It has been estimated that the approximate cost of these chsnges for this program revision submittal is approximately $20,000 - $25,000 including procedure changes that are also underway. Had these been the only program revisions and procedural changes the total cost is estimated to be $30,000 - $35,000 to complete and implement all aspects of the changes.

As a comment on your report, I am glad that the NMP 2 project has adequately addressed proper and comprehensive testing in this area.

Sincerely,

M. D. Jones

M.D. Jones
Supt. Operations - NMP 2

G.3 Cost Estimates Provided by Quad Cities
Attachment 2

"Cost Estimate for Proposed BNL Corrective
Actions at Quad Cities Station/
Core Spray Check Valve Test Tap"

Engineering $ 25,000

- Design Drawings
- Material Spec.
- Repair Program
- Seismic Analysis
- Modification Program

Construction (Per Line) $ 6,000

-	Fab	16 man-hrs.
-	Install	48 man-hrs.
-	NDE/Test	40 man-hrs
-	Misc. (Insulation)	26 man-hrs
-	Supervision	40 man-hrs.
		170

Materials (Per line) $ 1,700

-	Valves	$ 600 each (2)
-	Pipe & Fit	$ 300
-	Weld	$ 100
-	Misc Tools	$ 100
		$1,700

Total Cost $40,400 per unit
(2 lines)

3001K

APPENDIX H: Interfacing System LOCA Analysis for a Plant That Does Not Perform Any Leak Testing of Pressure Isolation Valves

In this section, a plant model representing a plant that does not perform any leak testing of pressure isolation valves (PIVs) is described. It was assumed that this plant was identical to Peach Bottom in terms of configuration and general operating practices except that no leak testing is performed on the PIVs. The leak tests that Peach Bottom currently performs are LLRT and operational hydrostatic tests. They have been described in Section 4.1. Basically, the analysis for Peach Bottom has been modified to remove any credit taken for leak testing of the pressure isolation valves to form a base case model. Table H.1 summarizes the results of the base case analysis. Also listed in Table H.1 are the results for this plant assuming that the air-operated check valves are leak tested after valve maintenance and at every refueling outage. For a plant that does not perform leak testing, failures of the PIVs may go undetected. Therefore, the frequency of an overpressurization of low pressure piping occurring increases from year to year. The results shown in Figure H.1 are the average over the 30 years of remaining plant life. Tables H.2 to H.6 summarize the calculations for the individual lines. Tables H.7 to H.11 provide the corresponding results if leak testing of the air-operated check valves were to be implemented. (They essentially represent the Peach Bottom model with corrective actions one and three for Peach Bottom included therein.)

The changes that were made to the Peach Bottom model to remove the existing credit for leak testing are discussed in the following:

1. LPCI, CS, HPCI, and RCIC Lines

These injection lines have the same valve arrangement, i.e., an air-operated check valve, a normally closed MOV and a normally open MOV. For the plant that does not perform any leak testing, any failure of the air-operated check valve will go undetected. Therefore, the probability that the check valve is in a failed state increases linearly with time. It was assumed that the plant has operated 10 years and has 30 years of remaining plant life. Therefore, the average probability that the check valve is in a failed condition in the remaining plant life is

$$\frac{1}{30}\int_0^{30} \lambda(t + 10)dt = 25\lambda,$$

where λ is the frequency of check valve failure. This effectively increases the frequency of valve failure by a factor of 25.

Failure of the MOVs is expected to be detectable by several means. The operability test of the injection valves in LPCI and CS lines requires pressurizing the pipe section between the two injection valves. If one injection valve fails open, it will be impossible to perform the operability test. The operability test also measures the stroke time of the valves and the current through the valve motor. Abnormality in these measurements may also indicate valve failure. The operability test for the injection valves of HPCI and RCIC does not require pressurization of any pipe section, and only

valve stroke time is measured. Therefore, if an injection valve fails to close fully after stroking, the failure may go undetected. However, such a failure mode may only divert some feedwater flow and is not of interest. Other failure modes involve gross failure of the MOV and are expected to be detectable by valve operability testing. Therefore, the only effect of no leak testing on the injection valves is that the exposure time of the injection valves is doubled, i.e., the conditional probability of injection valve failure given that the check valve has already failed is doubled. This is because the expected time at which the check valve failure occurs, given that the check valve has already failed, is before the year that is being considered. Therefore, if the injection valve fails any time during the year, an overpressurization will occur. Tables H.3 to H.6 summarize the calculations for these lines.

2. Feedwater Line

The frequency of overpressurization for this line is estimated based on the San Onofre-1 experience in which the check valve failure was caused by low flow induced vibration. Leak testing of the check valves is not expected to have any effect on the occurrence of such common cause failures.

3. RHR Suction From Recirculation

Two failure modes of the RHR suction valves were considered, rupture and failure to fully reclose. The rupture failure mode is expected to be detected by stroking the valve. Therefore, not leak testing for these valves simply increases the probability of the failure mode that the valve fails to close fully after it has been stroked. Similar to the failure rate of the air-operated check valves, this probability is increased by a factor of 25. Since both suction valves may fail due to this failure mode, a factor of 50 increase in the frequency of the leak-rupture or rupture-leak failure mode results.

Table H.1
Comparison of a Plant That Does Not Perform Any PIV Leak Testing With One That Does

Plant	f(OP)	S_2	A	CDF
A Plant With No Leak Testing	$1.53x10^{-2}$	$1.09x10^{-4}$	$2.20x10^{-5}$	$1.86x10^{-5}$
Same Plant With Leak Testing*	$4.03x10^{-3}$	$1.44x10^{-6}$	$4.14x10^{-6}$	$1.97x10^{-7}$

*Leak test of air-operated check valves after maintenance and at every refueling.

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

Table H.2
Summary of Results by System for a Plant That Does Not Perform Any Leak Testing

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	4.12E-03	2.65E-02	4.10E-05	1.62E-05	1.64E-05
CS	3.82E-03	5.52E-03	3.82E-05	1.75E-06	1.93E-06
HPCI	3.18E-03	9.34E-03	0.00E+00	4.53E-08	4.53E-08
RCIC	3.18E-03	1.74E-03	0.00E+00	8.45E-09	8.45E-09
Feedwater	1.00E-03	3.95E-03	0.00E+00	3.95E-06	4.42E-09
RHR Suction	2.59E-05	7.48E-02	2.59E-05	1.93E-08	1.40E-07
Vessel Head Spray	3.81E-06	2.65E-02	3.81E-06	1.00E-09	1.87E-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 H.3
Summary Calculations for LPCI of a Plant That Does Not Perform Any Leak Testing

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Browns Ferry-1 Hatch-2 (Reverse Air)	3.67E-02	3.85E-06 Failure to Reclose	1.42E-07	0.00E+00	1.42E-09	0.00E+00
		1.20E-03 Rupture	4.41E-05	2.65E-02	4.41E-07	1.17E-08
		6.00E-03 Inadvertent Opening	2.20E-04	2.65E-02	2.20E-06	5.84E-08
		8.10E-04 Transfer Open	2.98E-05	2.65E-02	2.97E-07	7.89E-09
Browns Ferry Scenario (Reverse Air, Inadvertent Opened)			7.35E-04	2.65E-02	7.35E-06	1.95E-07
Cooper (Foreign Material)	1.84E-02	3.85E-06 Failure to Reclose	7.08E-08	0.00E+00	7.08E-10	0.00E+00
		1.20E-03 Rupture	2.20E-05	2.65E-02	2.15E-07	5.84E-07
		6.00E-03 Inadvertent Opening	1.10E-04	2.65E-02	1.07E-06	2.92E-06
		8.10E-04 Transfer Open	1.49E-05	2.65E-02	1.45E-07	3.94E-07
Pilgrim-1 Sept. 29,1983 (Rusted Linkage)	1.84E-02	3.85E-06 Failure to Reclose	7.08E-08	0.00E+00	7.08E-10	0.00E+00
		1.20E-03 Rupture	2.20E-05	2.65E-02	2.20E-07	5.84E-09
		6.00E-03 Inadvertent Opening	1.10E-04	2.65E-02	1.10E-06	2.92E-08
		8.10E-04 Transfer Open	1.49E-05	2.65E-02	1.49E-07	3.94E-09
LaSalle-1 Sept. 14,1983 (Misalignment of Gears)	1.84E-02	3.85E-06 Failure to Reclose	7.08E-08	0.00E+00	7.08E-10	0.00E+00
		1.20E-03 Rupture	2.20E-05	2.65E-02	2.15E-07	5.84E-07
		6.00E-03 Inadvertent Opening	1.10E-04	2.65E-02	1.07E-06	2.92E-06
		8.10E-04 Transfer Open	1.49E-05	2.65E-02	1.45E-07	3.94E-07
Four Remaining Incidents (Leakage)	7.35E-02	3.85E-06 Failure to Reclose	2.83E-07	0.00E+00	2.83E-09	0.00E+00
		1.20E-03 Rupture	8.82E-05	0.00E+00	8.82E-07	0.00E+00
		6.00E-03 Inadvertent Opening	4.41E-04	0.00E+00	4.41E-06	0.00E+00
		8.10E-04 Transfer Open	5.95E-05	0.00E+00	5.95E-07	0.00E+00

See Note 3.

Table H.4
Summary Calculations for CS of a Plant That
Does Not Perform Any Leak Testing

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Browns Ferry-1	3.67E-02	3.85E-06	1.42E-07	0.00E+00	1.42E-09	0.00E+00
Hatch-2		Failure to Reclose				
(Reverse Air)		1.20E-03	4.41E-05	5.52E-03	4.41E-07	2.43E-09
		Rupture				
		6.00E-03	2.20E-04	5.52E-03	2.20E-06	1.22E-08
		Inadvertent Opening				
		8.10E-04	2.98E-05	5.52E-03	2.98E-07	1.64E-09
		Transfer Open				
Browns Ferry Scenario			7.35E-04	5.52E-03	7.35E-06	4.06E-08
Pilgrim-1	1.84E-02	3.85E-06	7.08E-08	0.00E+00	7.08E-10	0.00E+00
Sept. 29,1983		Failure to Reclose		0.00E+00	7.08E-10	0.00E+00
(Rusted Linkage)		1.20E-03	2.20E-05	5.52E-03	2.20E-07	1.22E-09
		Rupture				
		6.00E-03	1.10E-04	5.52E-03	1.10E-06	6.08E-09
		Inadvertent Opening				
		8.10E-04	1.49E-05	5.52E-03	1.49E-07	8.21E-10
		Transfer Open				
LaSalle-1	1.84E-02	3.85E-06	7.08E-08	0.00E+00	7.08E-10	0.00E+00
Sept. 14,1983		Failure to Reclose				
(Misalignment of Gears)		1.20E-03	2.20E-05	5.52E-03	2.19E-07	1.22E-07
		Rupture				
		6.00E-03	1.10E-04	5.52E-03	1.10E-06	6.08E-07
		Inadvertent Opening				
		8.10E-04	1.49E-05	5.52E-03	1.48E-07	8.21E-08
		Transfer Open				
Four Remaining	7.35E-02	3.85E-06	2.83E-07	0.00E+00	2.83E-09	0.00E+00
Incidents		Failure to Reclose				
(Leakage)		1.20E-03	8.82E-05	0.00E+00	8.82E-07	0.00E+00
		Rupture				
		6.00E-03	4.41E-04	0.00E+00	4.41E-06	0.00E+00
		Inadvertent Opening				
		8.10E-04	5.95E-05	0.00E+00	5.95E-07	0.00E+00
		Transfer Open				

Notes: AOV = Failure Rate of Air-Operated Check Valve (/ry).
MOV = Probability of MOV Failure.
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).

Table H.5
Summary of Calculations for HPCI of a Plant
That Does Not Perform Any Leak Testing

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Browns Ferry-1 Hatch-2 (Reversed Air)	3.67E-02	1.20E-03 Rupture	4.41E-05	9.34E-03	0.00E+00	4.12E-10
		6.00E-03 Inadvertent Opening	2.20E-04	9.34E-03	0.00E+00	2.06E-09
		8.10E-04 Transfer Open	2.98E-05	9.34E-03	0.00E+00	2.78E-10
Browns Ferry Scenario (Reverse Air, Inadvertent Opened)			7.35E-04	9.34E-03	0.00E+00	6.86E-09
Cooper (Foreign Material)	1.84E-02	1.20E-03 Rupture	2.20E-05	9.34E-03	0.00E+00	2.06E-09
		6.00E-03 Inadvertent Opening	1.10E-04	9.34E-03	0.00E+00	1.03E-08
		8.10E-04 Transfer Open	1.49E-05	9.34E-03	0.00E+00	1.39E-09
Pilgrim-1 Sept. 29,1983 (Rusted Linkage)	1.84E-02	1.20E-03 Rupture	2.20E-05	9.34E-03	0.00E+00	2.06E-10
		6.00E-03 Inadvertent Opening	1.10E-04	9.34E-03	0.00E+00	1.03E-09
		8.10E-04 Transfer Open	1.49E-05	9.34E-03	0.00E+00	1.39E-10
Pilgrim Scenario (Rusted Linkage, HE in Testing)			7.35E-04	9.34E-03	0.00E+00	6.86E-09
LaSalle-1 Sept. 14,1983 (Misalignment of Gears)	1.84E-02	1.20E-03 Rupture	2.20E-05	9.34E-03	0.00E+00	2.06E-09
		6.00E-03 Inadvertent Opening	1.10E-04	9.34E-03	0.00E+00	1.03E-08
		8.10E-04 Transfer Open	1.49E-05	9.34E-03	0.00E+00	1.39E-09

Notes: AOV = Failure Rate of Air-Operated Check Valve (/ry).
MOV = Probability of MOV Failure.
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).

Table H.6
Summary of Calculations for RCIC of a Plant
That Does Not Perform Any Leak Testing

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Browns Ferry-1 Hatch-2 (Reversed Air)	3.67E-02	1.20E-03 Rupture	4.41E-05	1.74E-03	0.00E+00	7.67E-11
		6.00E-03 Inadvertent Opening	2.20E-04	1.74E-03	0.00E+00	3.84E-10
		8.10E-04 Transfer Open	2.98E-05	1.74E-03	0.00E+00	5.18E-11
Browns Ferry Scenario (Reverse Air, Inadvertent Opened)			7.35E-04	1.74E-03	0.00E+00	1.28E-09
Cooper (Foreign Material)	1.84E-02	1.20E-03 Rupture	2.20E-05	1.74E-03	0.00E+00	3.84E-10
		6.00E-03 Inadvertent Opening	1.10E-04	1.74E-03	0.00E+00	1.92E-09
		8.10E-04 Transfer Open	1.49E-05	1.74E-03	0.00E+00	2.59E-10
Pilgrim-1 Sept. 29,1983 (Rusted Linkage)	1.84E-02	1.20E-03 Rupture	2.20E-05	1.74E-03	0.00E+00	3.84E-11
		6.00E-03 Inadvertent Opening	1.10E-04	1.74E-03	0.00E+00	1.92E-10
		8.10E-04 Transfer Open	1.49E-05	1.74E-03	0.00E+00	2.59E-11
Pilgrim Scenario (Rusted Linkage, HE in Testing)			7.35E-04	1.74E-03	0.00E+00	1.28E-09
LaSalle-1 Sept, 14,1983	1.84E-02	1.20E-03 Rupture	2.20E-05	1.74E-03	0.00E+00	3.84E-10
		6.00E-03 Inadvertent Opening	1.10E-04	1.74E-03	0.00E+00	1.92E-09
		8.10E-04 Transfer Open	1.49E-05	1.74E-03	0.00E+00	2.59E-10

Notes: AOV = Failure Rate of Air-Operated Check Valve (/ry).
MOV = Probability of MOV Failure.
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).

Table H.7
Summary of Results by System With Leak Testing

Line	f(OP)	P(Rupture)	S2	A	CDF
LPCI	3.53E-05	2.65E-02	3.52E-07	1.58E-07	1.59E-07
CS	2.94E-05	5.52E-03	2.94E-07	3.25E-10	1.69E-09
HPCI	1.48E-03	9.34E-03	0.00E+00	7.16E-09	7.16E-09
RCIC	1.48E-03	1.74E-03	0.00E+00	1.33E-09	1.33E-09
Feedwater	1.00E-03	3.95E-03	0.00E+00	3.95E-06	4.42E-09
RHR Suction	7.71E-07	7.48E-02	7.52E-07	1.93E-08	2.27E-08
Vessel Head Spray	4.53E-08	2.65E-02	4.49E-08	4.01E-10	6.10E-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 H.8
Summary Calculations for LPCI -- With Leak Testing

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Cooper (Foreign Material)	7.35E-04	1.93E-06 Failure to Reclose	1.42E-09	0.00E+00	1.42E-11	0.00E+00
		6.00E-04 Rupture	4.41E-07	2.65E-02	4.29E-09	1.17E-08
		3.00E-03 Inadvertent Opening	2.20E-06	2.65E-02	2.15E-08	5.84E-08
		4.05E-04 Transfer Open	2.98E-07	2.65E-02	2.90E-09	7.89E-09
Pilgrim-1 Sept. 29,1983 (Rusted Linkage)	7.35E-04	1.93E-06 Failure to Reclose	1.42E-09	0.00E+00	1.42E-11	0.00E+00
		6.00E-04 Rupture	4.41E-07	2.65E-02	4.41E-09	1.17E-10
		3.00E-03 Inadvertent Opening	2.20E-06	2.65E-02	2.20E-08	5.84E-10
		4.05E-04 Transfer Open	2.98E-07	2.65E-02	2.97E-09	7.89E-11
Four Remaining Incidents (Leakage)	2.94E-03	1.93E-06 Failure to Reclose	5.66E-09	0.00E+00	5.66E-11	0.00E+00
		6.00E-04 Rupture	1.76E-06	0.00E+00	1.76E-08	0.00E+00
		3.00E-03 Inadvertent Opening	8.82E-06	0.00E+00	8.82E-08	0.00E+00
		4.05E-04 Transfer Open	1.19E-06	0.00E+00	1.19E-08	0.00E+00

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

Table H.9
Summary Calculations for CS - With Leak Testing

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Pilgrim-1 Sept. 29,1983 (Rusted Linkage)	7.35E-04	1.93E-06 Failure to Reclose	1.42E-09	0.00E+00	1.42E-11	0.00E+00
		6.00E-04 Rupture	4.41E-07	5.52E-03	4.41E-09	2.43E-11
		3.00E-03 Inadvertent Opening	2.20E-06	5.52E-03	2.20E-08	1.22E-10
		4.05E-04 Transfer Open	2.98E-07	5.52E-03	2.98E-09	1.64E-11
Four Remaining Incidents (Leakage)	2.94E-03	1.93E-06 Failure to Reclose	5.66E-09	0.00E+00	5.66E-11	0.00E+00
		6.00E-04 Rupture	1.76E-06	0.00E+00	1.76E-08	0.00E+00
		3.00E-03 Inadvertent Opening	8.82E-06	0.00E+00	8.82E-08	0.00E+00
		4.05E-04 Transfer Open	1.19E-06	0.00E+00	1.19E-08	0.00E+00

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

Table H.10
Summary of Calculations for HPCI - With Leak Testing

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Cooper (Foreign Material)	7.35E-4	6.00×10^{-4} Rupture	4.41×10^{-7}	9.34E-03	0.00E+00	4.12×10^{-11}
		3.00E-03 Inadvertent Opening	2.20×10^{-6}	9.34E-03	0.00E+00	2.06×10^{-10}
		4.05E-04 Transfer Open	2.98×10^{-7}	9.34E-03	0.00E+00	2.78×10^{-11}
Pilgrim-1 Sept. 29,1983 (Rusted Linkage)	7.35E-4	6.00×10^{-4} Rupture	4.41×10^{-7}	9.34E-03	0.00E+00	4.12×10^{-12}
		3.00E-03 Inadvertent Opening	2.20×10^{-6}	9.34E-03	0.00E+00	2.06×10^{-11}
		4.05E-04 Transfer Open	2.98×10^{-7}	9.34E-03	0.00E+00	2.78×10^{-12}
Pilgrim Scenario (Rusted Linkage, HE in Testing)			7.35E-04	9.34E-03	0.00E+00	6.86E-09

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

Table H.11
Summary of Calculations for RCIC - With Leak Testing

Experience	AOV	MOV	f(OP)	P(Rupture)	S2	A
Cooper (Foreign Material)	7.35E-4	6.00×10^{-4} Rupture	4.41×10^{-7}	1.74E-03	0.00E+00	7.67×10^{-12}
		3.00E-03 Inadvertent Opening	2.20×10^{-6}	1.74E-03	0.00E+00	3.84×10^{-11}
		4.05E-04 Transfer Open	2.98×10^{-7}	1.74E-03	0.00E+00	5.18×10^{-12}
Pilgrim-1 Sept. 29,1983 (Rusted Linkage)	7.35E-4	6.00×10^{-4} Rupture	4.41×10^{-7}	1.74E-03	0.00E+00	7.67×10^{-13}
		3.00E-03 Inadvertent Opening	2.20×10^{-6}	1.74E-03	0.00E+00	3.84×10^{-12}
		4.05E-04 Transfer Open	2.98×10^{-7}	1.74E-03	0.00E+00	5.18×10^{-13}
Pilgrim Scenario (Rusted Linkage, HE in Testing)			7.35E-04	1.74E-03	0.00E+00	1.28E-09

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

Notes for Appendix H Tables

Note 1: f(OP) = Frequency of Overpressurization (/ry).
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).
CDF = Core Damage Frequency (/ry).

Note 2: 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).

Note 3: AOV = Failure Rate of Air-Operated Check Vale (/ry).
MOV = Probability of MOV Failure.
f(OP) = Frequency of Overpressurization (/ry).
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).

Note 4: Beta = Beta Factor for Common Cause Failure.
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).

Note 5: Beta = Beta Factor for Common Cause Failure.
AOV = Failure Rate of Air-Operated Check Vale (/ry).
MOV = Probability of MOV Failure.
f(OP) = Frequency of Overpressurization (/ry).
S_2 = Frequency of Unisolated Small LOCA (/ry).
A = Frequency of Large LOCA (/ry).

APPENDIX I: Consequence Calculations

The consequences were calculated using the CRAC2[1-2] computer code. The consequences of principal interest are person-rem, deaths, and decontamination area.

The techniques of consequence analysis are discussed in the Reactor Safety Study (WASH-1400)[3] and the PRA Procedures Guide,[4] and, therefore, the details are omitted here.

The consequence codes consider five processes that account for most of the ways in which people can accumulate a radiation dose after radioactivity has been released to the atmosphere from an accident:

a. Inhalation;
b. Cloudshine (external exposure from passing cloud);
c. Groundshine (external exposure from deposited material);
d. Ingestion; and
e. Inhalation of resuspended material.

The first three mechanisms are by far the most important in contributing to potential high-dose early effects. Lower doses leading to latent effects can come from any of the pathways, especially if interdiction does not preclude ingestion and cleanup does not reduce contamination.

In CRAC2, the dose response is piece-wise linear due to irradiation of the bone marrow, lung, and GI tract. The total risk is then:

$$R = R_1 + (1-R_1)R_2 + (1-R_1)(1-R_2)R_3$$

where R_1, R_2, and R_3 are the risks to the three organs, respectively.

Site Data

A "generic" site was considered using the average U.S. population density of about 100 people per square mile. The plant was assumed to be a 3412 MWt BWR.

The weather data consists of hourly weather observations of wind speed, wind direction, stability class, and precipitation. The data was not taken from a single year, but was averaged in a manner that represents the long-term average weather behavior. The code sort this data into 29 weather categories (called bins), as discussed in the CRAC2 Model Manual,[2] so that low probability weather conditions can be adequately sampled.

The site weather input was taken to be that for Indian Point simply for calculational convenience. Other site weather data would yield somewhat different numerical results, however, it is important to note that the relative magnitudes and relationships of the consequence analysis would be expected to hold. The weather summaries Indian Point are given in Table I.1. The stability is ranked in six categories (A, B, C, D, E, F) ranging from the most dispersive to the least dispersive. Category A, with rapid dispersion, represents a sunny afternoon with low wind speeds. Category F, with little spread of the plume with distance, would occur late at night or just before

dawn if wind speeds were very low. In addition, there are weather bins for rain conditions, both at time of release and at later times, and for changing wind conditions which produces a slowing down of the plume. Both of these conditions could produce higher doses at greater distances than would otherwise occur.

Source Terms

The characterization of a given release category is called the source term. The factors of interest are the timing and duration of the release, the release fractions and the plume energy. The timing of the release is used for radioactive decay. The duration of release is used in CRAC2 to account for continuous releases by adjusting for horizontal dispersion because of wind meander (CRAC2 considers only puff releases). The release fractions are for groupings of isotopes that have similar chemical characteristics. The energy of the release is used to calculate plume rise.

The source terms shown in Table I.2 represent early radiological releases (V scenario) associated with a MARK I BWR and were taken from NUREG/CR-4624 (BMI-2139 Vol. I). The first column represents the release corresponding to an unscrubbed case while the second column assumes a scrubbing of the release. It should be noted that a decontamination factor (DF) of 10 was assumed except for the nobel gases.

The releases were assumed to occur one half hour after scram with a five hour duration. The energy of the release was 30 MW for the unscrubbed case and zero for the scrubbed case.

Results of the Consequence Calculations

Results were calculated assuming a realistic public response to an evacuation within 10 miles starting one half hour after the release. The results are given in Table I.3 for deaths, injuries, person-rem within 50 miles and loss of use of the land due to land interdiction without decontamination.

References

1. Ritchie, L. T. et al., "Calculations of Reactor Accident Consequences Version 2.CRAC2: Computer Code User's Guide," NUREG/CR-2326, February 1983.

2. Ritchie, L. T. et al., "CRAC2 Model Description," NUREG/CR-2552, March 1984.

3. U.S. Nuclear Regulatory Commission, "Reactor Safety Study: An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," WASH-1400, NUREG-75/014, October 1975.

4. American Nuclear Society, "PRA Procedures Guide," NUREG/CR-2300, September 1981.

Table I.1
One Year of New York City Meteorological Data
Summarized Using Weather Bin Categories

Weather Bin	Number of Sequences	Percent
1. R (0)	697	7.96
2. R (0-5)	12	.14
3. R (5-10)	62	.71
4. R (10-15)	102	1.16
5. R (15-20)	75	.86
6. R (20-25)	67	.76
7. R (25-30)	61	.70
8. S (0-10)	24	.27
9. S (10-15)	16	.18
10. S (15-20)	18	.21
11. S (20-25)	14	.16
12. S (25-30)	18	.21
13. A-C 1,2,3	168	1.92
14. A-C 4,5	892	10.18
15. D 1	0	0.00
16. D 2	61	.70
17. D 3	226	2.58
18. D 4	948	10.82
19. D 5	3325	37.96
20. E 1	0	0.00
21. E 2	27	.31
22. E 3	167	1.91
23. E 4	682	7.79
24. E 5	270	3.08
25. F 1	0	0.00
26. F 2	116	1.32
27. F 3	310	3.54
28. F 4	402	4.59
29. F 5	0	0.00
	8760	100.0

R = Rain starting within indicated interval (miles).
S = Windspeed slowdown occurring within indicated interval (miles).
A-C, D,E,F = Stability categories.
1(0-1), 2(1-2), 3(2-3), 4(3-5), 5(GT 5) = Wind speed intervals (meters/second).

Table I.2
Comparison of Environmental Releases for
Unscrubbed and Scrubbed Cases

Species	Unscrubbed	Scrubbed
I	0.46	0.046
C_s	0.44	0.044
T_e	0.26	0.026
S_x-B_a	0.24	0.024
Ru	1.4E-6	1.4E-7
L_a-C_e	2.0E-2	2.0E-3

Table I.3
Results of Consequence Calculations

	Deaths	Injuries	Person-Rem	Total Land Cost w/o Decontamination ($)
Unscrubbed	5.9	91	3.26E6	$1.76E09
Scrubbed	0	0.35	1.51E6	$3.69E08