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High-Pressure Coolant Injection (HPCI) System Performance, 1987 1993 Final

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ABSTRACT

This report documents an analysis of the safety-related performance of the high-pressure coolant injection (HPCI) system at U.S. commercial boiling water reactor plants during the period 1987 1993. Both a risk-based analysis and an engineering analysis of trends and patterns were performed on data from HPCI system operational events to provide insights into the performance of the HPCI system throughout the industry and at a plant-specific level. Comparison was made to Probabilistic Risk Assessment/Individual Plant Evaluations for 23 plants to indicate where operational data either support or fail to support the assumptions, models, and data used to develop HPCI system unreliability.

FIN E8246 Technical Assistance in Reliability and Risk Analysis

EXECUTIVE SUMMARY

This report presents a performance evaluation of the high-pressure coolant injection (HPCI) system at 23 U.S. commercial boiling water reactors (BWRs). The study was based on the operating experience from 1987 through 1993, as reported in Licensee Event Reports (LERs) and monthly nuclear power plant operating reports. The objectives of the study were:

1. To estimate HPCI system unreliability based on operational data, and to compare the results with the assumptions, models, and data used in Probabilistic Risk Assessments/Individual Plant Evaluations (PRA/IPEs).

2. To provide an engineering analysis of the trends and patterns seen in the HPCI system operational data.

The HPCI system was modeled using standard PRA techniques, and the operational data were used to develop the basic event failure probabilities to allow quantification of the models. Between-plant comparisons were made on the basis of these models. The results, using the actual plant operational data, were then compared to the results from current PRA/IPEs. The engineering analysis included both an industry-wide and a plant-specific examination. Investigation of trends and patterns in system failures and demands were based on operational time, low-power license date, subsystem, cause, and method of discovery.

Of the 303 events reported which involved the HPCI system during the evaluation period, 145 were classified as HPCI failures and 63 as HPCI actual unplanned demands occurring from a reactor pressure vessel (RPV) low-water level condition. In addition, a review of the Accident Sequence Precursor events for the same time period identified 19 events related to a demand of the HPCI system; 7 identified a system malfunction during an unplanned demand, 8 were unplanned demands with no system malfunction, and 4 were potential demands of the system when it was out-of-service for maintenance/testing.

The results of the unreliability estimates computed from the operational data and the comparison with the PRA/IPEs are as follows:

- The observed industry-average unreliability of the HPCI system, taking credit for recovery actions, is 0.056. If recovery is excluded from the calculation, as is appropriate for comparisons with PRA/IPEs, the unreliability is 0.14. These numbers assume that the system is demanded to inject only once during a mission. If, instead, the normally closed injection motor-operated valve (MOV) between the HPCI pump discharge and the RPV is required to open more than once, the unreliability including recovery increases to 0.24. Although observed in the operational data, most PRA/IPEs do not model injection valve cycling.

- The observed plant-specific unreliability on a single injection, taking credit for recovery, ranged from 0.050 to 0.067. This variation was within the uncertainty range for each plant, as shown in the left side plot of Figure ES-1.

- The observed plant-specific unreliabilities for a single injection without taking credit for recovery actions is consistent with the values used in 12 of 23 PRA/IPEs, as shown in the right-side of Figure ES-1. Ten of the other 11 plants had observed unreliabilities greater than a factor of 3 higher than, and outside the uncertainty bounds of, the plant-specific PRA/IPE unreliabilities. The one remaining plant had insufficient information in the PRA/IPE to allow for a comparison.

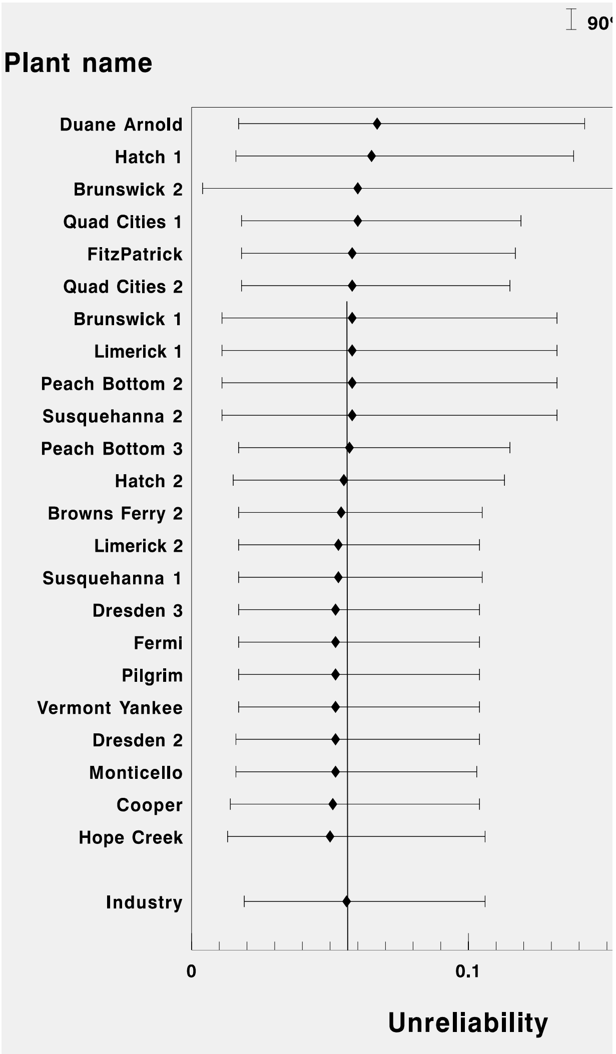
X Comparison between the observed plant-specific basic event probabilities and the plant-specific PRA/IPE basic events probabilities yields the following:

- The observed failure-to-run probability is greater than 10 times higher than that used in 13 of the PRA/IPEs, with 9 of the 13 PRA/IPE estimates exceeded by greater than 30 times.

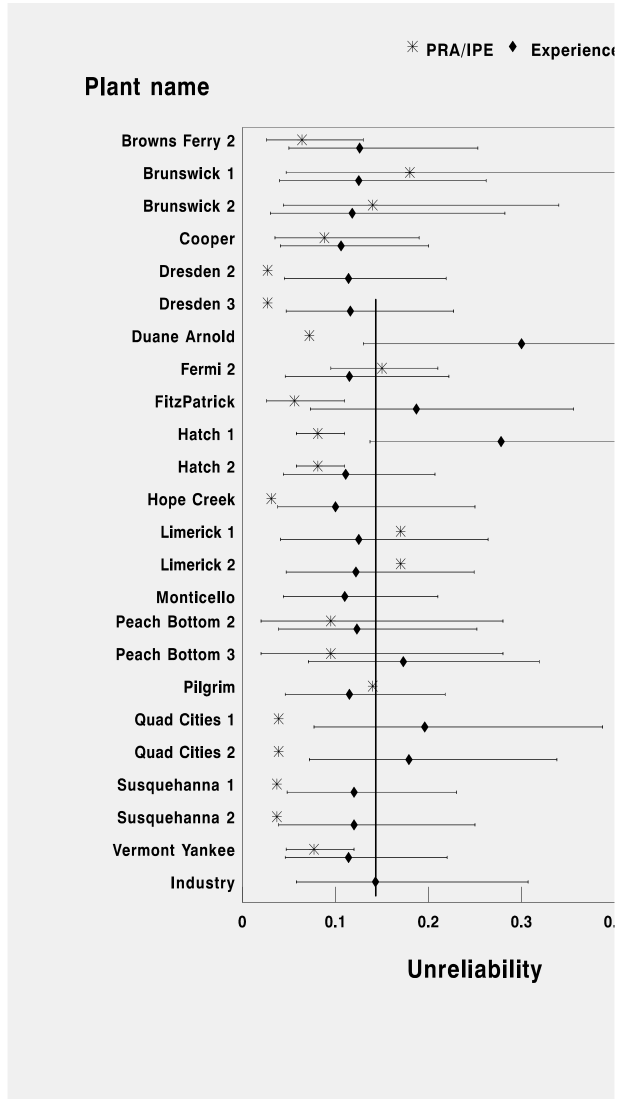
- The observed failure-to-start probability was in general agreement with the PRA/IPEs. However, two plants had probabilities greater than 6 times higher than those used in the PRA/IPEs, and the mean value used in those PRA/IPEs fell outside the uncertainty intervals-based on operational data.

- The observed failure probability of the injection valve to open on the initial system demand to restore RPV level is greater than 10 times higher than that used in 10 of the PRA/IPEs.

- The probability of being out of service for observed maintenance and testing for all plants is in agreement with the PRA/IPEs.



Unreliability with recovery actions included.



Unreliability comparisons without recovery.

Figure ES-1. HPCI system plant-specific unreliabilities compared to the plant-specific PRA/IPEs.

The principal results of the engineering review of the operational data are as follows:

- X As shown in Figure ES-2, no correlation was seen between the plant's low-power license date and either the unreliability per operational year, or the rate of failures per operational year.

- X While the rate of HPCI system unplanned demands and failures per plant operational year decreased during the 7-year period, the associated unreliability showed no significant trend. These trends are shown in Figure ES-3.

- X Unplanned demand failures dominated the contribution to HPCI system unreliability prior to 1991, and cyclic test failures dominated HPCI system unreliability from 1991 on. There were no observed unplanned demand failures after 1991.

- X The component failures and their failure mechanisms observed during unplanned demands were different than those found during the performance of surveillance tests.

- X Failures associated with instrumentation and control circuits occurred twice as often when the HPCI system was in standby than during surveillance tests, with no failures observed during unplanned demands.

- X Surveillance test failures were dominated by failures to start (74%), and unplanned demands were dominated by failures to run (55%).

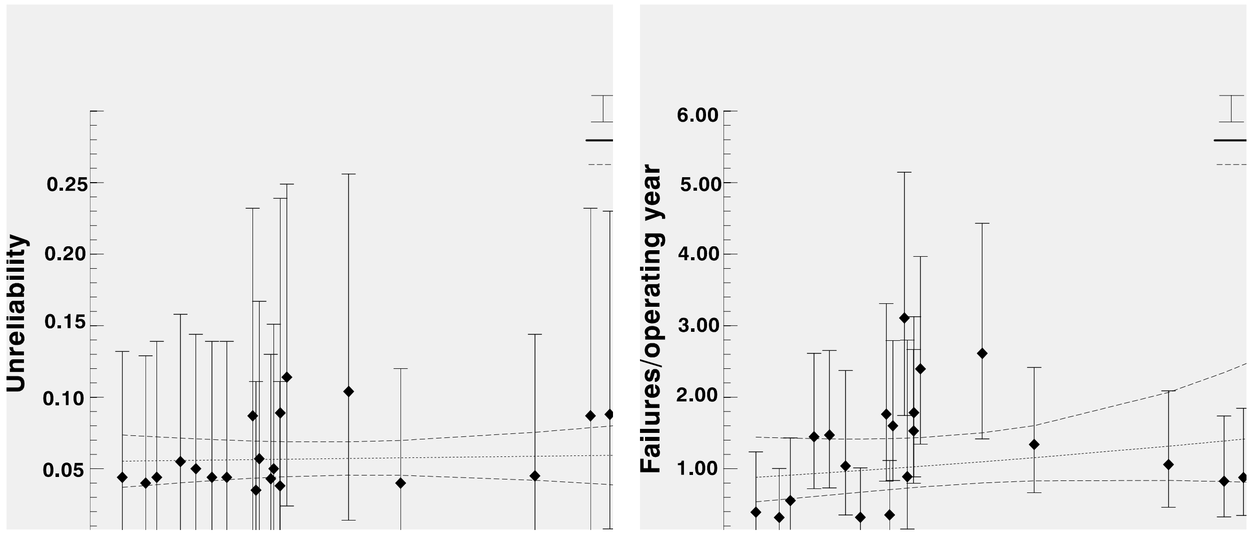
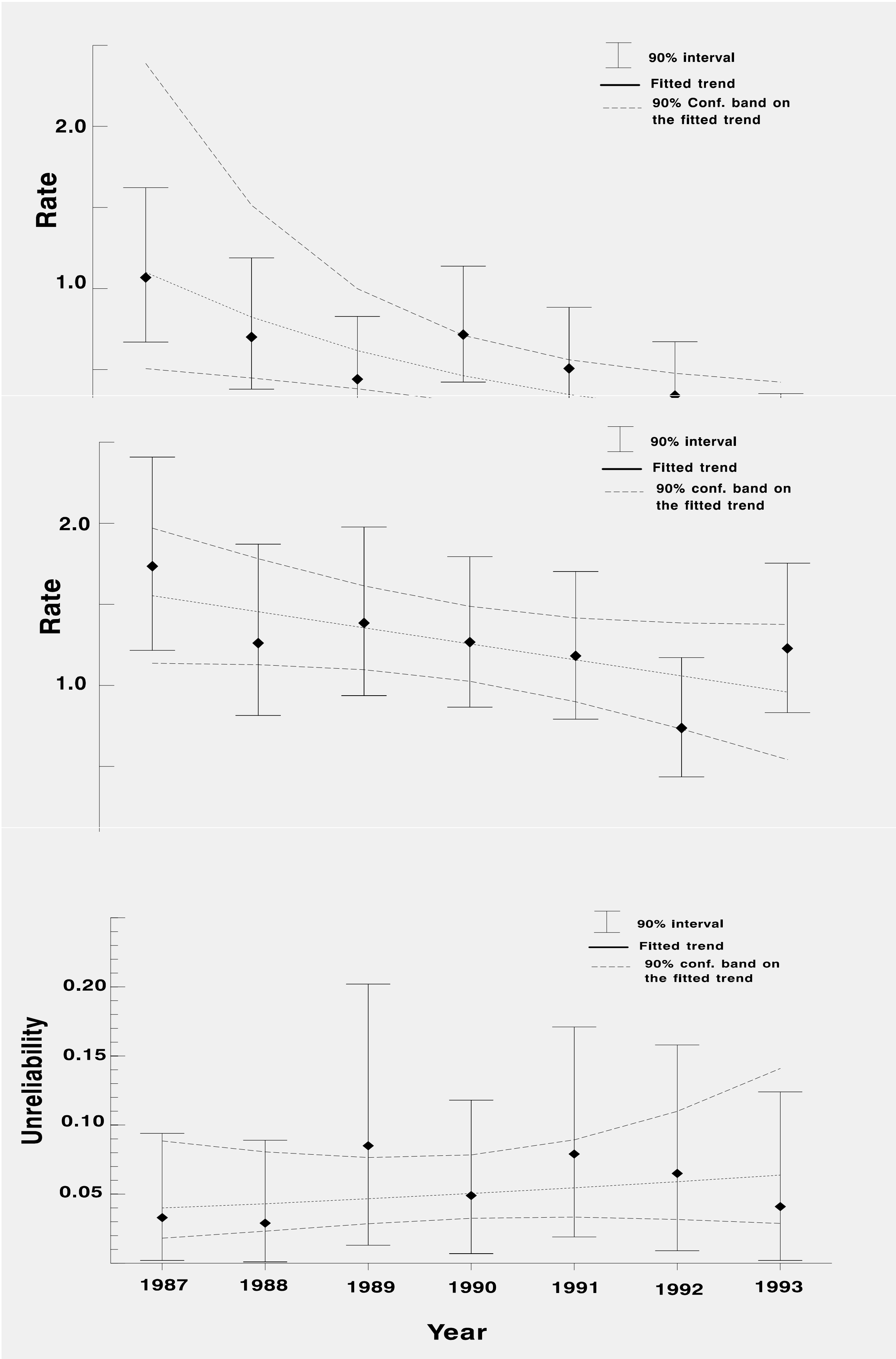


Figure ES-2. Plots of plant-specific HPCI system unreliabilities and failure rates per operational year plotted against plant-specific low power license date.



System unreliability

Figure ES-3. HPCI system unplanned demand rate, failure rate, and unreliability, per calendar year.

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FIGURES

TABLES

ACRONYMS

AEOD	Analysis and Evaluation of Operational Data (NRC Office)
ASEP	Accident Sequence Evaluation Program
ASP	Accident Sequence Precursor
BWR	boiling water reactor
CCDP	conditional core damage probability
CRD	control rod drive
CST	condensate storage tank
ECCS	emergency core cooling systems
FRFTR	failure to recover from failure to run
FRFTS	failure to recover from failure to start
FRO	failure (of the injection valve) to reopen
FTR	failure to run
FTS	failure to start
FTSO	failure to start other than injection valve
FTSV	failure to start because of injection valve
HPCI	high-pressure coolant injection
HVAC	heating, ventilating, and air conditioning
INEL	Idaho National Engineering Laboratory
IPE	individual plant examination
LER	Licensee Event Report
MCC	motor control center
MOOS	maintenance and testing out of service
MOV	motor-operated valve

NRC	Nuclear Regulatory Commission
PRA	probabilistic risk assessment
RCIC	reactor core isolation cooling
RPV	reactor pressure vessel
SCSS	Sequence Coding and Search System
SRV	safety relief valve
TDP	turbine-driven pump

TERMINOLOGY

Cyclic surveillance test The test of the system typically performed once per operating cycle, and required to be performed at least every 18 months.

Demand rate The number of unplanned demands divided by the operating time, in years.

Failure An inoperability in which the safety injection function is lost.

Failure rate The number of failures divided by the operating time, in years.

Failure of injection valve to reopen (FRO) A failure of the injection valve to open the second and subsequent times during a single HPCI mission.

Failure to run (FTR) A failure of the HPCI system after the system reaches 90% of rated coolant flow. May or may not include FRO depending on context.

Failure to start (FTS) A failure of the HPCI system prior to the system reaching 90% of rated coolant flow. This was sometimes divided into failure to start because of injection valve problems (FTSV), and failure to start for other reasons (FTSO).

Inoperability An event in which the HPCI system is not fully operable as defined by applicable plant technical specifications or Safety Analysis Reports.

Maintenance out of service (MOOS) A failure of the HPCI system due to the HPCI system being out of service for testing or maintenance.

P-value The probability that the data set would be as extreme as it is, if the assumed model is correct. It is the significance level at which the assumed model would barely be rejected by a statistical test. A small P-value indicates strong evidence against the assumed model.

Recovery The overcoming of a prior failure solely by operator actions without the need for any maintenance action or repair.

Safety function available (SFA) An inoperability of the HPCI system in which the safety injection function is not lost.

Safety function lost (SFL) Loss of the ability of the HPCI system to provide its safety injection function; same as failure.

Safety injection function To start and to inject coolant to the RPV with at least 90% of the flow rate required by the plant technical specifications for the entire required mission time, automatically and without any operator action.

Statistically significant Having a P-value of 0.05 or smaller when compared to the assumed model.

Unplanned demand An automatic or manual signal for the HPCI system to start, as a result of actual need for RPV inventory restoration. (Unplanned demands as a result of a high drywell pressure condition were not observed in the operational data)

Unreliability Probability that the system will fail to complete its required mission when demanded. This includes the contributions of MOOS, FTS, FTR and all other failure modes identified in the operational data. Recovery may or may not be included, depending on the context. The mission may or may not require repeated cycling of the injection valve, depending on the context.

High-Pressure Coolant Injection (HPCI) System Performance, 1987 1993

1. INTRODUCTION

The U.S. Nuclear Regulatory Commission (NRC), Office for Analysis and Evaluation of Operational Data (AEOD) has, in cooperation with other NRC Offices, undertaken an effort to ensure that the stated NRC policy to expand the use of probabilistic risk assessment (PRA) within the agency is implemented in a consistent and predictable manner. As part of this effort, the AEOD Safety Programs Division has undertaken a review of nuclear power plant operating experience data. The approach is to compare the results as estimated in PRAs to actual operating experience. The first phase of the review involves the identification of risk-important systems from a PRA perspective and the performance of reliability and trending analysis on these identified systems. As part of this review, a risk-related performance evaluation of the HPCI system in U.S. commercial boiling water reactors (BWRs) was undertaken. The evaluation was directed at estimating HPCI system performance using actual operating experience.

The HPCI system performance study was based upon the operating experience during the period from 1987 through 1993, as reported in Licensee Event Reports (LERs) and monthly nuclear power plant operating reports. The objectives of the study were:

X To estimate HPCI system reliability based on operational data, and compare the results with the assumptions, models, and data used in Probabilistic Risk Assessment/Individual Plant Evaluations (PRA/IPEs).

X To provide an engineering analysis of the trends and patterns seen in the HPCI system operational data.

The report is arranged as follows. Section 1 provides the introduction. Section 2 describes the scope of the study, describes the HPCI system, and briefly describes the data collection and analysis methods. Section 3 presents the results of the risk-based analysis of the operational data. Section 4 provides the results of the engineering analysis of the operational data. Section 5 contains the references. Appendix A provides a detailed explanation of the methods used for data collection, characterization, and analysis. Appendix B gives summary lists of the data. Appendix C summarizes the detailed statistical analyses used to determine the results presented in Sections 3 and 4.

2. SCOPE OF STUDY

This study documents an analysis of the operational experience from 1987-1993 of the 23 U.S. commercial BWRs that have a dedicated HPCI system. Table 1 lists these plants along with their associated number of operating years. Operating years for each plant were estimated by calendar time minus all periods when the main generator was off-line for more than two calendar days. LER data were not collected for a given calendar year if there was no operating time in that year. Plants with no operational time during the study period were excluded from the study. Details of the calculation of operating time are provided in Appendix A, and plant exclusions are provided in Appendix B.

This analysis focused only on the emergency core cooling system (ECCS) coolant injection function. The principal elements of the study process are briefly described in Section 2.1 to provide an orientation to the detailed discussions that follow.

2.1 Description of System

The HPCI system is a single-train system that provides a reliable source of high-pressure coolant for cases where there is a loss of normal core coolant inventory. Figure 1 provides a simplified schematic diagram of the system.

The HPCI system consists of a steam turbine-driven pump, valves and valve operators, and associated piping, including that from the normal and alternate pump suction sources and the pump discharge up to the penetration of the main feedwater line. For this study, the part of the main feedwater line from the check valve upstream of the HPCI connection to the reactor vessel, including the check

Table 1. BWR plants with a dedicated HPCI system.

Plant	Docket	Operating years	Plant	Docket	Operating years
Browns Ferry 2	260	2.2	Limerick 1	352	5.7
Brunswick 1	325	3.8	Limerick 2	353	3.8
Brunswick 2	324	4.6	Monticello	263	6.3
Cooper	298	5.6	Peach Bottom 2	277	4.0
Dresden 2	237	5.1	Peach Bottom 3	278	3.5
Dresden 3	249	5.4	Pilgrim	293	3.9
Duane Arnold	331	5.6	Quad Cities 1	254	5.5
Fermi 2	341	5.6	Quad Cities 2	265	5.4
FitzPatrick	333	4.5	Susquehanna 1	387	5.7
Hatch 1	321	5.9	Susquehanna 2	388	6.1
Hatch 2	366	6.0	Vermont Yankee	271	6.2
Hope Creek	354	6.2			

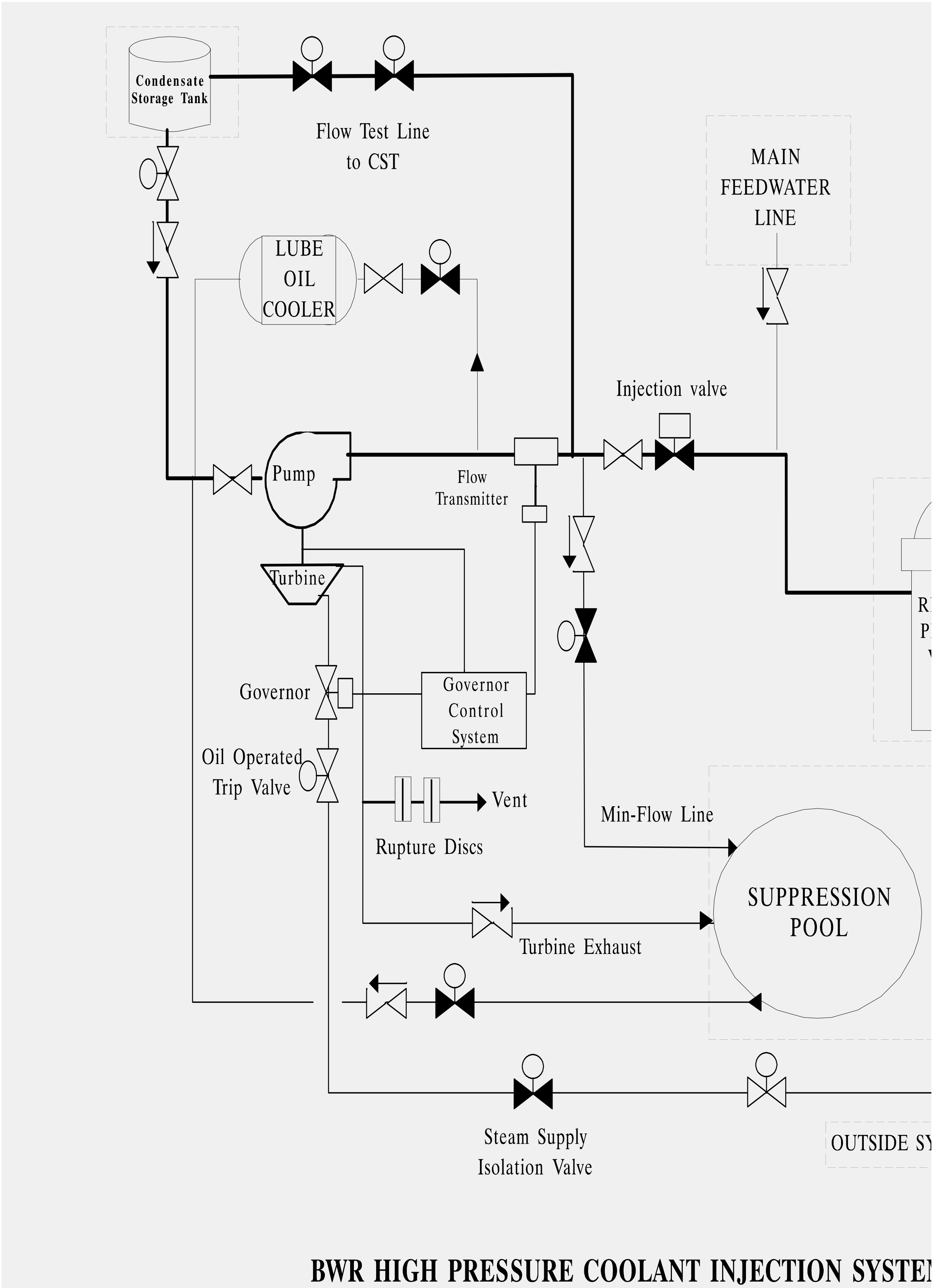

Figure 1. Simplified HPCI system diagram. (Elements enclosed in dashed lines are considered outside the system boundaries.)

valve, was considered part of the HPCI system. The steam turbine-driven pump includes all steam piping from the main steam line penetration to the turbine, and turbine exhaust piping to the suppression pool, valves and valve operators, gland sealing steam, and the turbine auxiliary oil system.

Additional components that were considered to be part of the HPCI system were the circuit breakers at the motor control centers (MCCs) (but not the MCCs themselves), the dedicated DC power system that supplies HPCI system power and the associated inverters, and the initiation and isolation logic circuits with their associated detectors. Heating, ventilating, and air conditioning (HVAC) systems and room cooling associated with the HPCI system were included. However, only a specific loss of service water to individual HPCI room coolers was included, and not the loss of the entire service water system.

Support system failures were considered for possible inclusion in this HPCI study. However, examination of the operational data found no cases when support system failures clearly caused HPCI failure. In addition, the support system failure contribution to the overall HPCI system failure probabilities in the PRAs was found to be small. Therefore, support systems were treated as outside the scope of this study.

The HPCI system is actuated by either a low reactor water level or a high drywell pressure. Initially the system operates in an open loop mode, taking suction from the condensate storage tank (CST) and injecting water into the reactor pressure vessel (RPV) via one of the main feedwater lines. When the level in the CST reaches a low-level setpoint, the HPCI pump suction is aligned to the suppression pool. To maintain RPV level after the initial recovery, the HPCI system is placed in manual control, which may involve controlling turbine speed, diverting flow through minimum-flow or test lines, cycling the injection motor-operated valve (MOV), or complete stop-start cycles.

The HPCI system is also manually used to help control RPV pressure following a transient. Although this is not part of the ECCS design function it is depended on, in approximately 90% of the PRA/IPEs. However, only approximately 10% of the PRA/IPEs that depend on this function model the pressure control operation. In this mode, the turbine-driven pump is operated manually with the injection valve closed and the full-flow test-line MOV open. Turbine operation with the injection line isolated and the test line open allows the turbine to draw steam from the RPV, thereby reducing RPV pressure. Operation of the system in the pressure control mode may also occur with intermittent injection of coolant to the RPV. As steam is being drawn off the RPV, the RPV water inventory is reduced, resulting in the need for level restoration. When level restoration is required, the injection valve is opened and the test-line MOV is closed. Upon restoration of RPV water inventory, the system is returned to the pressure control line-up. This cycling between injection and pressure control can be repeated as necessary.

2.2 Operational Data Collection

HPCI system operational data as reported in LERs from 1987-1993 were reviewed. Because HPCI is a safety system, any malfunctions that result in the system not being operable as defined by the respective plant technical specifications or the Safety Analysis Report are required by 10 CFR 50.73 to be reported in LERs.

In this report, the term *inoperability* is used to describe any LER-reported HPCI event in which the HPCI system did not meet the operability requirements identified in applicable plant technical specifications or the Safety Analysis Report. It is distinguished from the term *failure*, which is an inoperability for which the ECCS function of the system (the ability to inject coolant on demand) is lost. Failures include such problems as failures to start and failures to run. Inoperabilities include these, and also problems such as events related to seismic design, and administrative events such as late performance of a test. Because analysis of the containment isolation safety function of HPCI is not included in this study, events such as failures to isolate the turbine steam supply were regarded as inoperabilities, not failures.

2.2.1 Data Collection and Characterization

To identify HPCI inoperabilities reported in the LERs, the Sequence Coding and Search System (SCSS) LER database was searched for all records for the years 1987 1993 that refer to an actual or potential HPCI system inoperability. Each identified LER was read completely with care taken to properly classify each event and to ensure consistency of the classification for each event. The LERs were reviewed to determine the types of failures, the causes of the event, the method of discovery, and the component that contributed to the failure. The data were then entered into a database.

For failures, an additional event attribute was captured, the system failure mode. When the HPCI system receives an automatic start signal as a result of an actual low RPV water level condition, the system functions successfully if the turbine starts and obtains rated speed and coolant pressure, the injection valve opens, and coolant flow is delivered to the RPV until the flow is no longer needed. Failure may occur at any point in this process. For the purposes of this study, failure modes that can occur in response to an actual low RPV water level are defined below:

X Maintenance and testing out of service (MOOS) occurs if, due to testing or maintenance, the HPCI system is prevented from starting automatically

X Failure to start (FTS) occurs if the system is in service but fails to automatically start and achieve at least 90% of the rated coolant flow

X Failure to run (FTR) occurs if, at any time after the system is delivering at least 90% of the rated coolant flow, the HPCI system fails to maintain this flow while it is needed.

Recovery from initial failures is also important in estimating system reliability. To recover from failure to start, operators have to recognize that the system was in a failed state, restart it without performing maintenance (for example, without replacing components), and restore coolant flow to the RPV. An example of such a recovery would be an operator (a) noticing that the injection valve had not opened during an automatic start of the system, and (b) manually operating the control switch for this valve, thereby causing the MOV to open fully and allow rated coolant flow to the RPV. Recovery from failure to run is defined in a similar manner. Each failure was evaluated to determine whether recovery by the operator occurred.

To estimate unreliability, information on the frequency and nature of HPCI demands was needed. The LERs provided information on unplanned demands following plant transients that resulted in an actual low RPV water level condition, that is, an actual need for the HPCI system. Unplanned demands as a result of a high drywell pressure condition were not observed in the operational data. These demands were identified by searching the SCSS database for all LERS containing HPCI actuations. The identified LERS were screened to determine the nature of the HPCI demand. Many of the unplanned demands were actuations of only a part of the system. The partial actuations included suction path shifts and relay actuations related to plant maintenance actions, such as removal of a fuse or shorting of test leads. These partial actuations did not exercise the HPCI system in response to an actual need for injection. Therefore, these records were excluded from the count of HPCI unplanned demands.

Data from the surveillance tests that are performed approximately every operating cycle were also used to help estimate the system unreliability. Plant technical specifications require that the cyclic (18-month) surveillance tests simulate automatic actuation of the system throughout its emergency operating sequence and that each automatic valve actuate to the correct position. Because of the completeness of the cyclic surveillance test as compared to other surveillance tests (monthly, quarterly, etc.), cyclic surveillance tests were also used to estimate unreliability. For more details on the counting of unplanned demands and surveillance test demands, see Section A-1.2 in Appendix A.

2.3 Operational Data Analysis

The scope of the risk-based and engineering analysis of the operational data are based on two different data sets. Figure 2 illustrates the relationship between these data sets. Data set A represents all the LERs that identified a HPCI system inoperability from the above-mentioned SCSS database searches. Data set B represents the inoperabilities that resulted in a loss of the safety injection function (failure) of the HPCI system. Data set C represents the LERs that identified a HPCI system failure for which a demand frequency could be determined or estimated.

The risk-based analysis of the operational data was based on the determination of unreliability which considers only the failures of the HPCI system, and only those for which a demand frequency could be estimated or determined the failures that occurred during an unplanned demand or a cyclic surveillance test (data set C). The engineering analysis of the operational data examined all the system inoperabilities (data set A). In a few of these analyzes they focused only on the failures of the HPCI system (data set B) to highlight the events that were risk-significant.

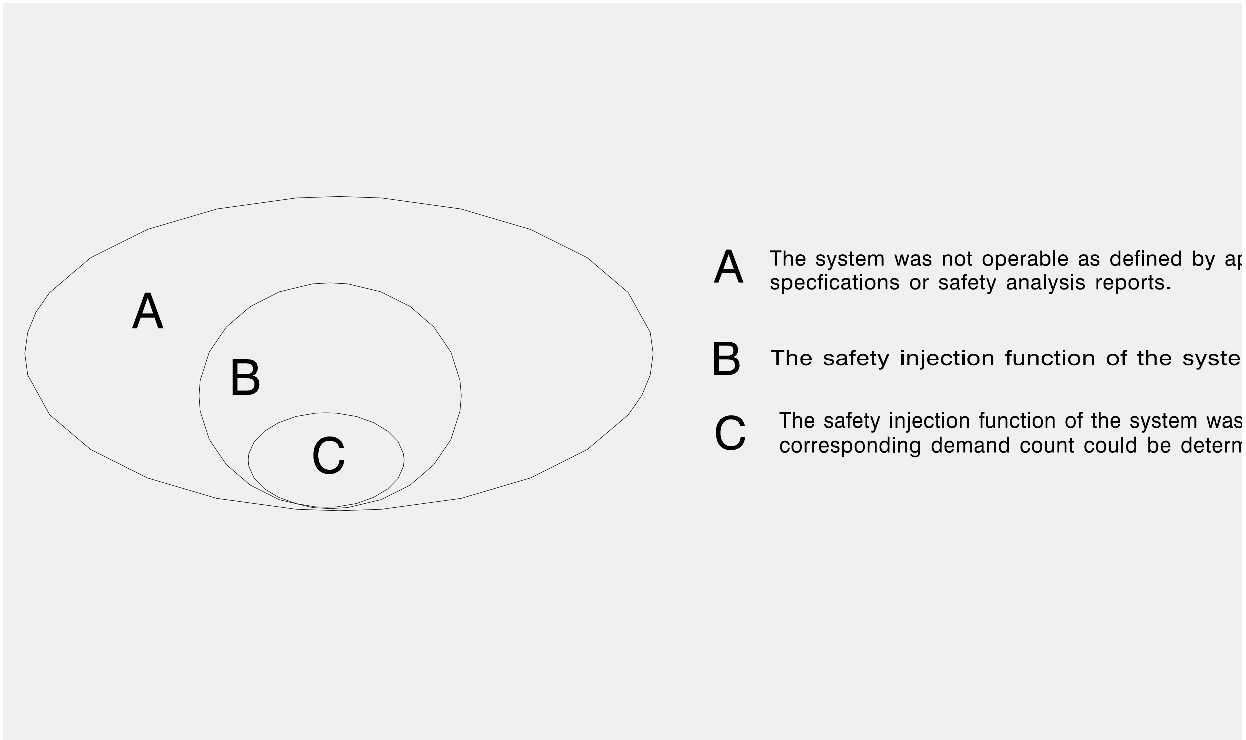

Figure 2. Illustration of the inoperability and failure data sets.

3. RISK-BASED ANALYSIS OF THE OPERATIONAL DATA

In this section, the operational data is analyzed in two ways. First, an evaluation of the HPCI system unreliability based on the operational data is performed to uncover trends and patterns within the data. Second, comparisons are made between HPCI system unreliabilities based on operational data and HPCI system unreliabilities reported in corresponding Probabilistic Risk Assessments/Individual Plant Examinations (PRA/IPEs). The objective of the trends and patterns analysis is to provide insights into the performance of the HPCI system on both an industry-wide and a plant-specific level. The objective of the comparisons are to indicate where operational data support or fail to support the assumptions, models, and data used in the PRA/IPEs.

HPCI system unreliability was calculated using a simple PRA model (fault tree). Basic event failure probabilities based on operational data (as developed in Appendix C) were used to quantify the model. HPCI system unreliability and basic event failure probabilities drawn from PRA/IPEs are included for comparison. A summary of the major findings is presented here.

- The observed industry-average unreliability of the HPCI system, taking credit for recovery actions, is 0.056. If recovery is excluded from the calculation, as is appropriate for comparisons with PRA/IPEs, the unreliability is 0.14. These numbers assume that the system is demanded to inject only once during a mission. If, instead, the normally closed injection motor-operated valve (MOV) between the HPCI pump discharge and the RPV is required to open more than once, the unreliability including recovery increases to 0.24. Although observed in the operational data, most PRA/IPEs do not model injection valve cycling.

- The observed plant-specific unreliability on a single injection, taking credit for recovery, ranged from 0.050 to 0.067. This variation was within the uncertainty range for each plant.

- The observed plant-specific unreliabilities for a single injection without taking credit for recovery actions is consistent with the values used in 12 of 23 PRA/IPEs. Ten of the other 11 plants had observed unreliabilities greater than a factor of 3 higher than, and outside the uncertainty bounds of, the plant-specific PRA/IPE unreliabilities. The one remaining plant had insufficient information in the PRA/IPE to allow for a comparison.

- Comparison between the observed plant-specific basic event probabilities and the plant-specific PRA/IPE basic events probabilities yields the following:

  - The observed failure-to-run probability is greater than 10 times higher than that used in 13 of the PRA/IPEs, with 9 of the 13 PRA/IPE estimates exceeded by greater than 30 times.

  - The observed failure-to-start probability was in general agreement with the PRA/IPEs. However, two plants had probabilities greater than 6 times higher than those used in the PRA/IPEs, and the mean value used in those PRA/IPEs fell outside the uncertainty intervals-based on operational data.

  - The observed failure probability of the injection valve to open on the initial system demand to restore RPV level is greater than 10 times higher than that used in 10 of the PRA/IPEs.

  - The probability of being out of service for observed maintenance and testing for all plants is in agreement with the PRA/IPEs.

3.1 Unreliability Based on Operational Data

3.1.1 Plant-specific Unreliability

The operational data for the HPCI system, from unplanned demands and cyclic surveillance tests, were statistically analyzed to develop basic event failure probabilities (see Appendices A and C). The following seven event categories were used:

Maintenance and testing Out Of Service (MOOS)
Failure To Start due to failures of hardware Other than the injection valve (FTSO)
Failure To Start due to injection Valve failure (FTSV)
Failure to Recover from FTS (FRFTS)
Failure To Run (FTR)
Failure to Recover from FTR (FRFTR)
Failure of injection valve to ReOpen (FRO)

Table 2 contains the failure probabilities and associated uncertainty intervals that were determined for each of the event categories (basic events) using the operational data. Where no significant differences were found between plants, the data were pooled and modeled as arising from a binomial distribution using the simple Bayes method. When between-plant variability could be estimated, the empirical Bayes method was employed. These methods are described in more detail in Appendix A, Section A-2.1.4.

Splitting the failure to start into two categories allowed use of the results of cyclic surveillance tests in the evaluation of FTSO. The cyclic surveillance tests were not usable in the evaluation of FTSV because the injection valve is not tested under the same conditions seen during unplanned demands (see Section A-1.2.2 of Appendix A and Section 4). FRO could have been included in the FTR basic event; however, because the failure is not modeled in most PRA/IPEs, and because the demands to reopen required special analysis, FRO was treated separately.

The unreliability of the HPCI system was calculated using the simple fault tree model shown in Figure 3. The model was constructed to reflect the logical combination of six of the seven failure modes developed using the operational data. FRO was excluded because it represents a failure mode not accounted for in most PRAs. FRO is addressed in Section 3.3. Table 3 contains the system unreliability and associated uncertainty intervals resulting from quantifying the fault tree using the data in Table 2. Also included in Table 3 are the probabilities for the four cut sets that make up the unreliability along with their percentage contribution.

Table 2. Basic event failure data and Bayesian probability information.

Basic event	Failures[a] (f)	Demands[a] (d)	Modeled variation	Distribution	Bayes Mean and 90% interval[b]
Maintenance and testing out of service (MOOS)	1	63	Sampling	Beta(1.5, 62.5)	(0.0028, 0.023, 0.060)
Failure to start, other than injection valve (FTSO)	11[c]	170[c]	Between plant	Beta(0.41, 6.4)	(0.0001, 0.060, 0.24)
Failure to start, injection valve (FTSV)	1	59[d]	Sampling	Beta(1.5, 58.5)	(0.0030, 0.025, 0.064)
Failure to recover from FTS (FRFTS)	0	5	Sampling	Beta(0.5, 5.5)	(0.0004, 0.0833, 0.31)
Failure to run (FTR)	7[e]	167[e]	Between plant	Beta(5.2, 117.4)	(0.017, 0.042, 0.076)
Failure to recover from FTR (FRFTR)	2	3	Sampling	Beta(2.5, 1.5)	(0.24, 0.63, 0.94)
Failure of injection valve to reopen (FRO)	3	19.2[f]	Sampling and uncertain demand count	Beta(2.3, 9.4)	(0.046, 0.20, 0.41)

a. Unplanned demands unless otherwise noted.

b. The middle number is the Bayes mean, and the end numbers form a 90% interval.

c. Composed of 4 failures during 59 unplanned demands (excludes 4 partial demands) and 7 failures during 111 cyclic surveillance tests.

d. Excludes 4 partial demands.

e. Composed of 3 failures during 56 unplanned demands (excludes 3 demands with FRO failures) and 4 failures during 111 cyclic surveillance tests.

f. This is a best estimate for a very uncertain number. The number of demands for multiple injections could be as small as 11 or as large as 46.

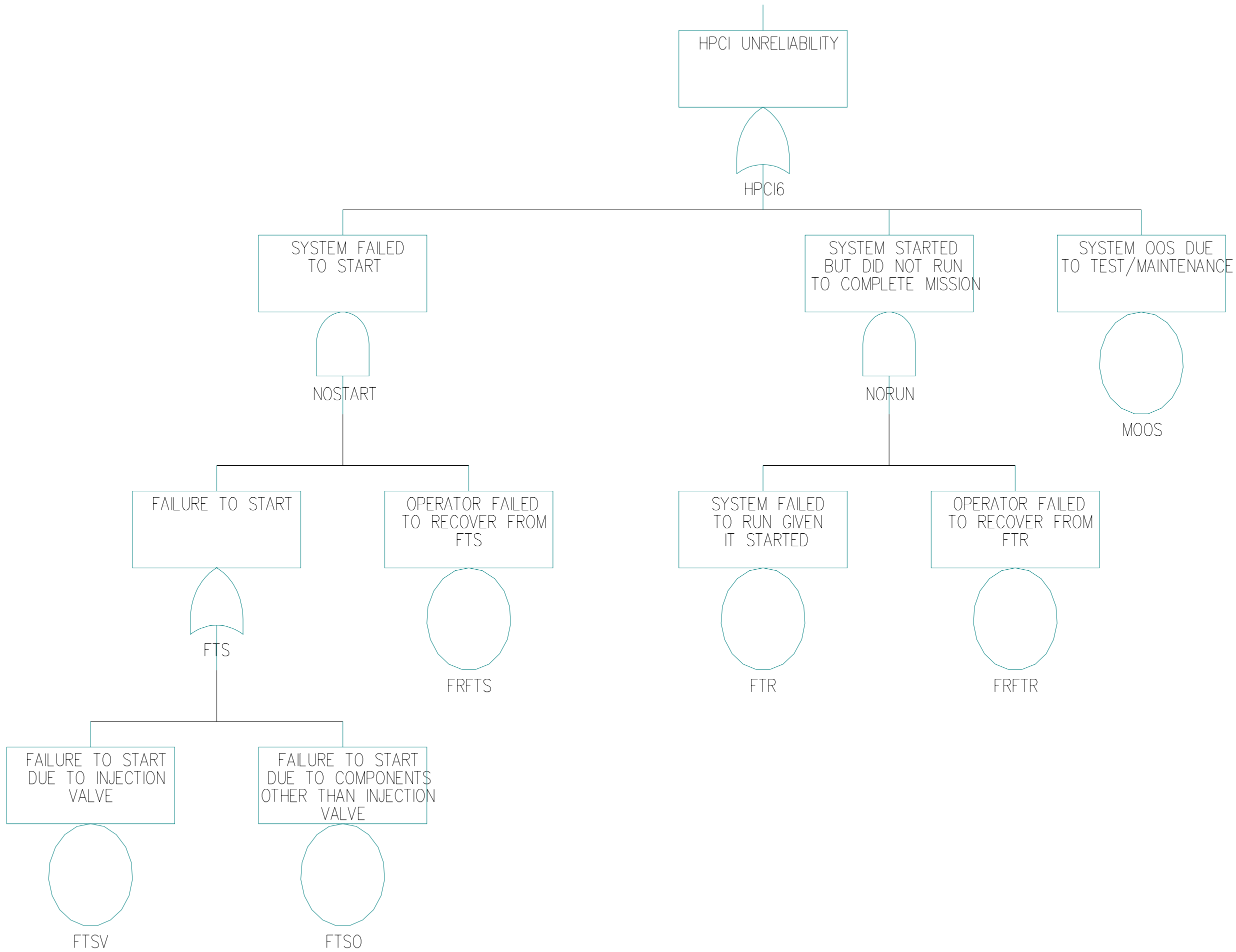

Figure 3. HPCI unreliability evaluation model (includes recovery actions, excludes failure of injection the valve to reopen.

Table 3. HPCI system unreliability, with recovery actions, based on industry-wide experience. Failure of the injection valve to reopen is excluded.

Contributor	Contributor probability	Percentage contribution[a]
FTR*FRFTR	0.026	47
MOOS	0.023	42
FTSO*FRFTS	0.0050	9
FTSV*FRFTS	0.0021	4
Unreliability	**0.056**[b]	**100**

a. Percentages sum to slightly more than 100% because the unreliability is the union of the four contributors, and the probability of this union is less than the sum of the individual probabilities.

b. The 90% uncertainty interval bounds are: 0.021, 0.11. This uncertainty corresponds to the randomness of the data and to between-plant variation. Other sources of uncertainty are discussed in Section C-4 of Appendix C.

The mission times of the observed demands were significantly shorter (less than 1 hour and typically just a few minutes) than the mission times of 5 to 24 hours that are typically used in modeling the HPCI system in plant PRA/IPEs. For this reason, the FTR probability and the overall unreliability value may be nonconservative relative to the performance that can be expected under reactor transient or accident conditions that require mission times greater than 1 hour.

Plant-specific unreliabilities were calculated to investigate differences between plants. Statistical analysis (details are provided in Appendix C) determined that MOOS, FTSV, FRFTS and FRFTR show no significant plant-to-plant variation while the failure probabilities for the FTSO and FTR events do show a plant-to-plant variation. As a result, plant-specific values for FTSO and FTR were determined. The plant-specific values are recorded in Appendix C (Tables C-3 and C-4) and were used to calculate the plant-specific unreliabilities shown in Figure 4. The industry-wide unreliability from Table 2 is also shown in Figure 4. Duane Arnold and Hatch 1 were found to have the highest HPCI system unreliability, but the differences between plants were very small. The unreliability estimates ranged from 0.050 to 0.067.

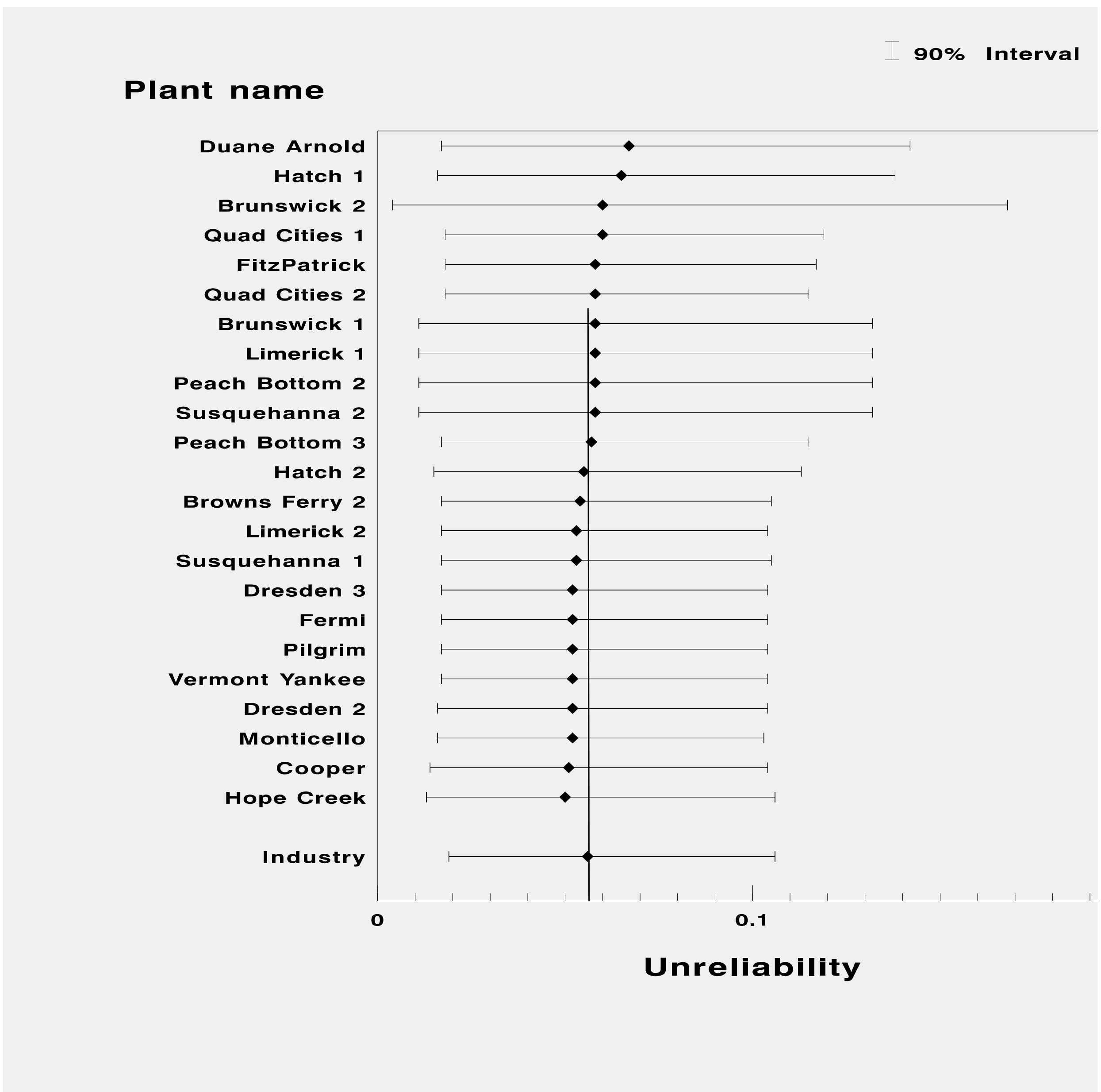

Figure 4. Plant-specific HPCI system unreliabilities, including recovery actions and excluding failure of the injection valve to reopen.

3.1.2 Investigation of Possible Trends

Unreliability was also calculated to reveal any overall trend that may be present. The method used here for calendar years and for plants differs from the method used to produce Figure 4; the statistical methods used for trend analysis of a sparse data set differs from the method used to determine plant-to-plant differences using a larger data set. The details are presented in Section A-2.1.4 of Appendix A and in Sections C-2 and C-3 of Appendix C. The calculated unreliabilities include operator action to recover from failures to start or run, and exclude the failure of the injection valve to reopen. Figure 5 shows the unreliability by year. The slope of the trend line is not statistically significant (P-value = 0.29).

To give some indication of the effect of the passage of time on HPCI performance, plant-specific unreliability was plotted against the plant low-power license date. The plot is shown in Figure 6 with 90% uncertainty bars plotted vertically. A trend line and a 90% confidence band for the fitted trend line are also shown in the figure. The slope of the trend line is not statistically significant (P-value = 0.77).

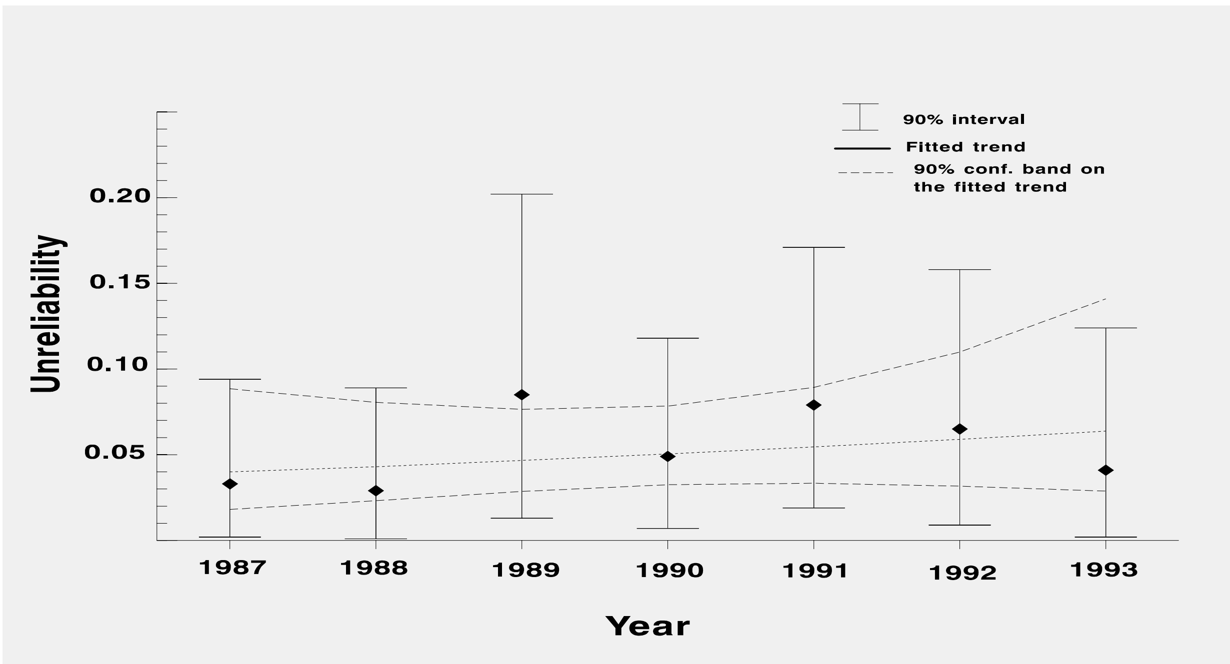

Figure 5. HPCI system unreliability by year, including recovery and excluding failure of the injection valve to reopen. The plotted trend is not statistically significant (P-value = 0.29).

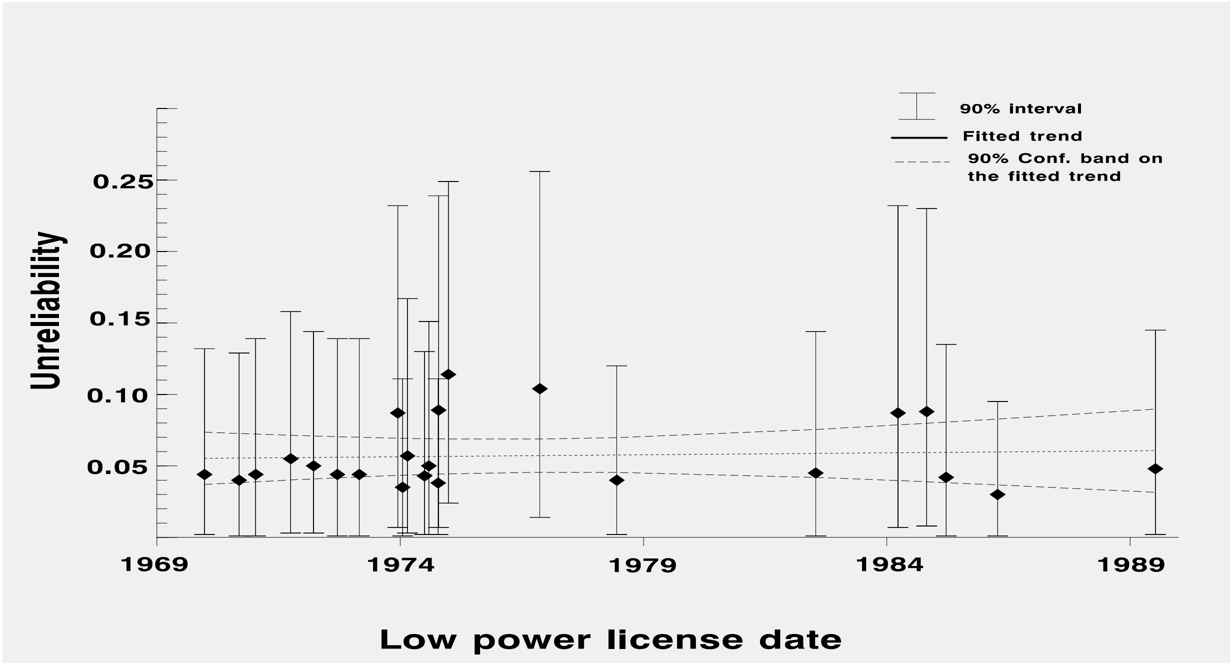

Figure 6. Plant-specific HPCI system unreliabilities plotted against low-power license dates. The unreliability includes recovery and excludes failure of the injection valve to reopen. The plotted trend is not statistically significant (P-value = 0.77).

3.2 PRA Comparison

The simple fault tree model shown in Figure 3 provided the logic for combining plant-specific event failure probabilities to calculate unreliabilities for comparison with the PRA/IPE values for the HPCI system. However, since most PRA/IPEs model recovery at the event tree level and not at the fault tree level, the recovery events FRFTS and FRFTR were not included. The plant-specific values used are listed in Appendix C, Tables C-3 and C-4. The values used for comparison were taken from 16 PRA/IPEs (References 1 through 16). Seven of the 16 PRA/IPEs reflect data from two plants each, thus every plant listed in Table 1 is represented.

The models in the PRA/IPEs include hardware failures, human errors, support system failures, and unavailabilities caused by tests or maintenance. Occasionally, operator actions and hardware failures associated with level- or pressure-control operations were also modeled at the fault tree level. To allow comparison of PRA/IPE results to unreliabilities based on operational data, contributions to the system unreliability from support systems and from manual level- or pressure-control operations were removed and the PRA/IPEs were requantified. This modification resulted in a change in reliability of less than 10% in all but two plants. The requantified PRA/IPE values, along with the plant-specific estimates of unreliability, are shown in Table 4 and graphically in Figure 7.

The PRA/IPE mean values of unreliability range from 0.027 to 0.18. The mean values of unreliability based on plant-specific experience range from 0.11 to 0.28, with all but two less than or equal to 0.20. The means differ by less than a factor of 2 in 12 of the plants and greater than 3 in 10 of the plants, as indicated by the "Comparison Ratio" column in Table 4.[a] In all 10 cases with differences greater than a factor of 3, the plant-specific experience is higher than the PRA/IPE value. In addition, in all 10 cases, the mean value from the PRA/IPE fell below the uncertainty intervals based on plant-specific experience. The primary cause of the difference in unreliability in 2 of the 10 cases was a difference in the FTSO failure probability. The difference in the other eight cases were caused primarily by differences in the FTR failure probability. The differences in failure probabilities are discussed in the following paragraphs.

In addition to the plant-specific unreliability comparisons, the PRA/IPE modeling of the HPCI system was analyzed by comparing the probabilities used for the basic events that contributed to the HPCI system unreliability. Figure 8 is a plot of plant-specific event failure probabilities from the PRA/IPE with the values determined using industry experience for each of the four basic failure modes.

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a. The HPCI system unreliability for Monticello was not reported in the PRA/IPE.

Table 4. Comparison of HPCI system unreliabilities from PRA/IPEs with corresponding plant-specific and industry-wide unreliabilities based on operational data.

PRA/IPE	PRA/IPE (Without support system failures and manual operation)	Plant-specific experience	Comparison ratio[a]
	B	C	C/B
Browns Ferry 2	0.064[b]	0.13	2.0
Brunswick 1	0.18	0.13	0.7
Brunswick 2	0.14	0.13	0.9
Cooper	0.088[b]	0.11	1.3
Dresden 2	0.027	0.11	4.1*
Dresden 3	0.027	0.12	4.4*
Duane Arnold	0.072[b]	0.30	4.2*
Fermi 2	0.15[b]	0.12	0.8
FitzPatrick	0.056	0.19	3.4*
Hatch 1	0.081[b]	0.28	3.5*
Hatch 2	0.081[b]	0.11	1.4
Hope Creek	0.031[b]	0.10	3.2*
Limerick 1	0.17[b]	0.13	0.8
Limerick 2	0.17[b]	0.12	0.7
Monticello	-[c]	0.11	-[c]
Peach Bottom 2	0.095	0.17	1.8
Peach Bottom 3	0.095	0.12	1.3
Pilgrim	0.14[b]	0.12	0.9
Quad Cities 1	0.039	0.20	5.1*
Quad Cities 2	0.039	0.18	4.6*
Susquehanna 1	0.037[b]	0.12	3.2*
Susquehanna 2	0.037[b]	0.12	3.2*
Vermont Yankee	0.054[b]	0.11	2.0
Industry		0.14	

a. Comparison ratios greater than 3 are noted with an asterisk.

b. Estimated value based on major basic events reported in PRA/IPE, fault tree not available.

c. Value not available.

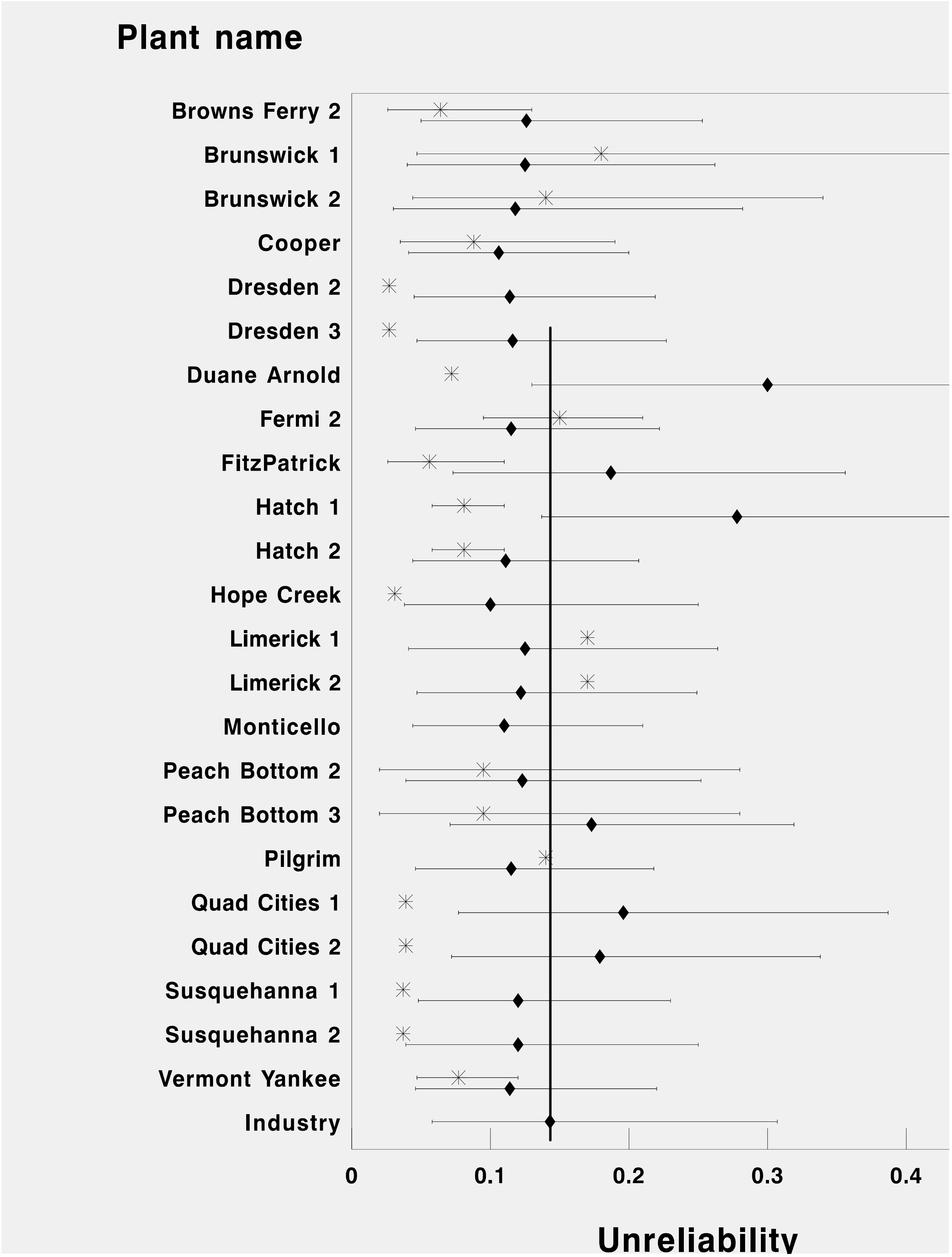


Figure 7. Comparison of HPCI unreliabilities from PRA/IPEs and industry experience. Recovery actions and failure of the injection valve to reopen are excluded.

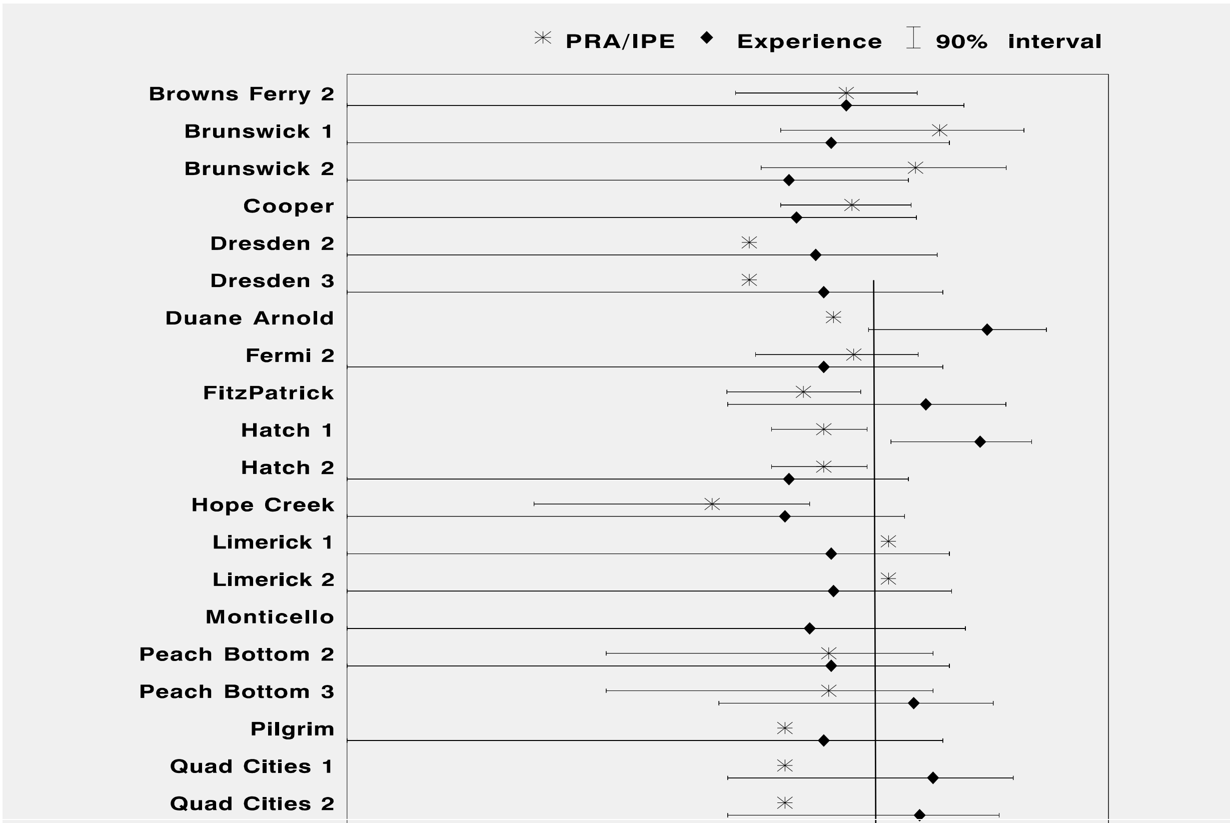
To make the comparisons, the basic events from the PRA/IPEs had to be grouped into the same four event categories as were used for the operational data. With only a few exceptions, the event categories include the following events from the PRA/IPEs:

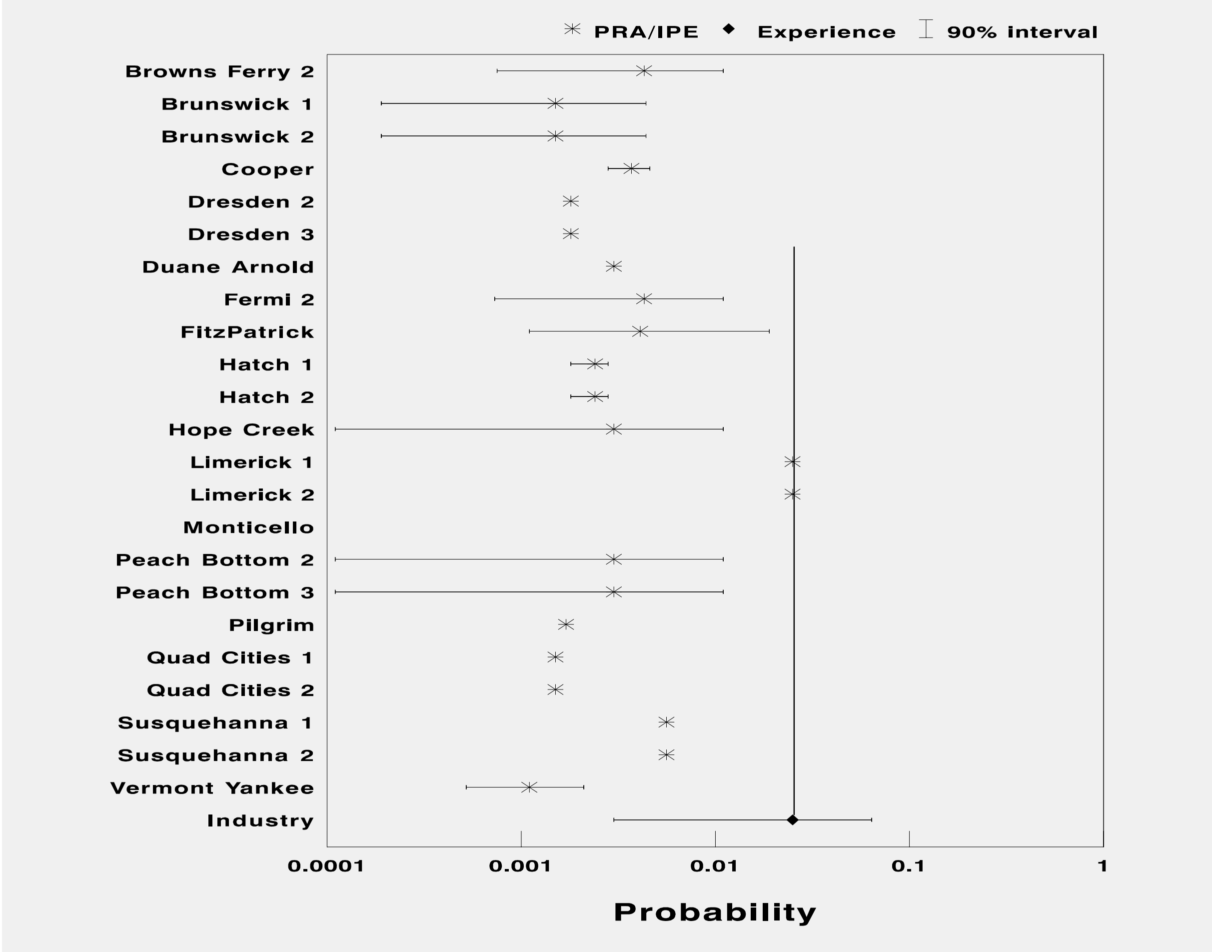
FTSO: Turbine-driven pump (TDP) failure to start, failure of steam supply valves to open including isolation MOV(s), trip and throttle valve and governor valve failures, failure of motor-driven auxiliary lube oil pump to start.

FTSV: Failure of injection valve to open.

FTR: TDP failure to run.

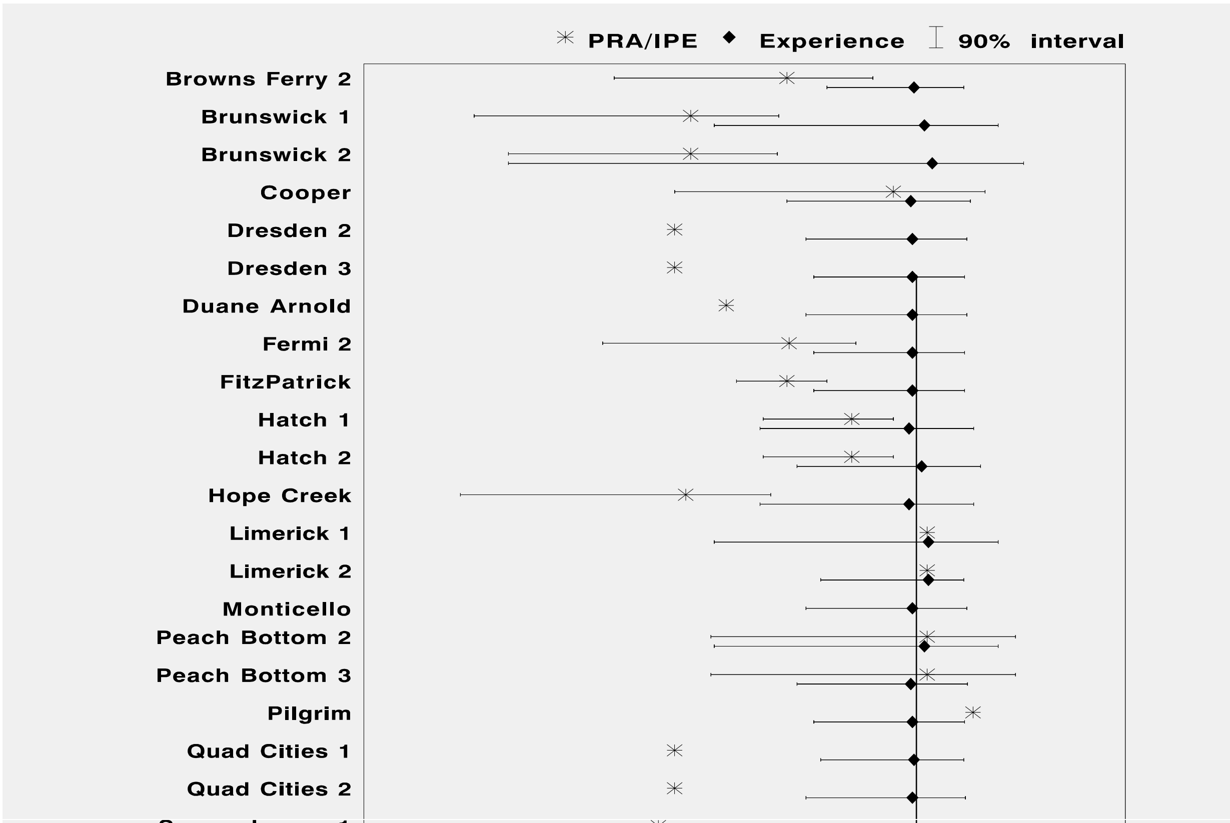
MOOS: TDP and major MOV testing and maintenance.

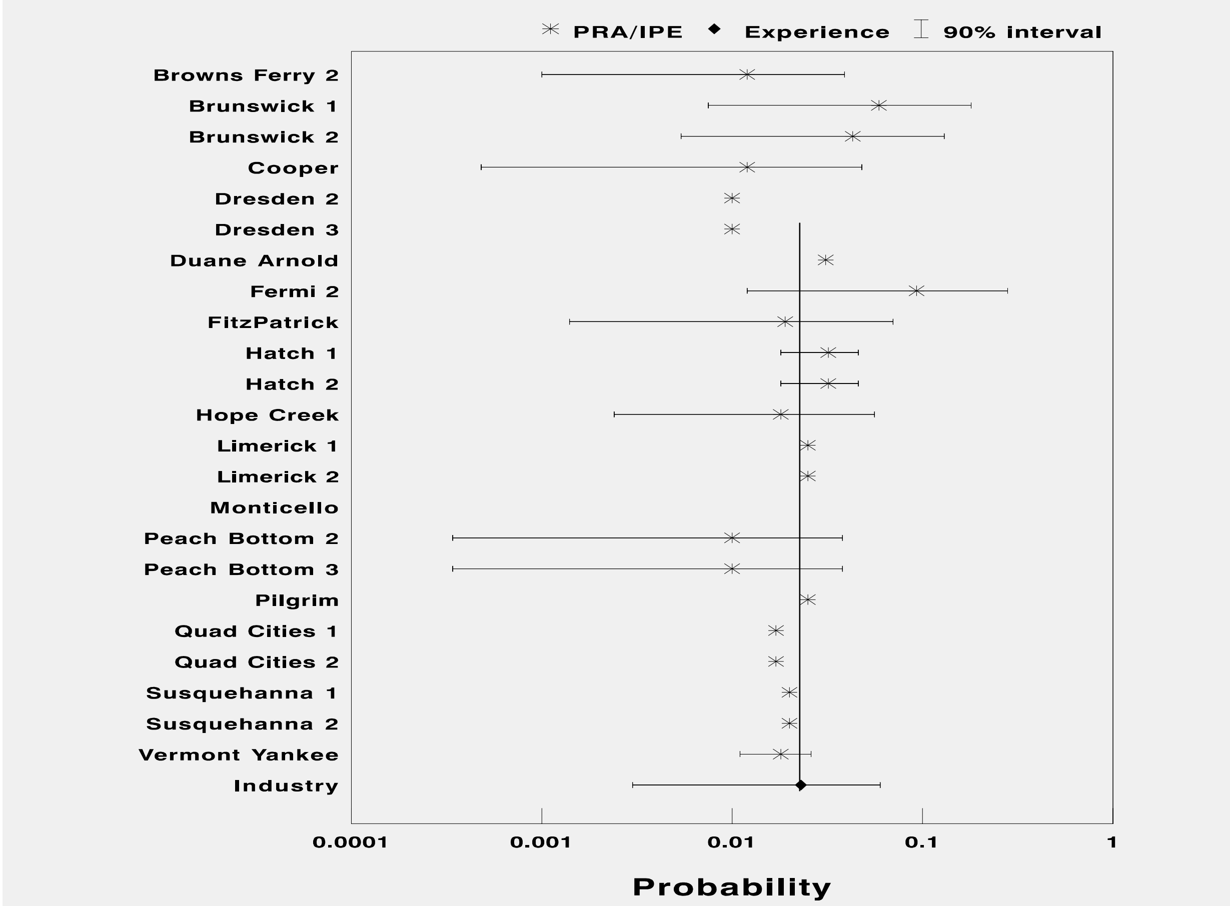




Failure to start due to failure of the injection valve

Figure 8. Comparisons of probabilities of plant-specific HPCI system failure mode from PRA/IPEs and industry experience.





Maintenance and testing out of service

Figure 8. (continued).

There were three exceptions to the events included in these categories: (a) the failure to start for Brunswick 1 and 2 included a steam drain failure (3% of the total unreliability); (b) instrumentation and control errors were rigorously modeled for FitzPatrick and were included as start failures (14% of the total unreliability); (c) the basic events for Limerick were atypical. In the case of Limerick, events defined as TDP-FTS or TDP-FTR were not specifically noted. As a result, the categorization of Limerick events is estimated based on the short description of the various basic events provided in the PRA/IPE. The events included in the four categories account for 99 100% of each PRA/IPE HPCI system unreliability, without support systems and without manual pressure- or level-control operation. While there may be numerous additional basic events in a given PRA/IPE, their effect on the system unreliability is quite small.

In reviewing the basic event failure probability comparisons in Figure 8, the criteria for identifying notable differences was that either the PRA/IPE mean value falls outside the uncertainty interval from industry experience or the mean values differed by more than a factor of 10. Table 5 lists those plants for which notable differences were identified.

The Duane Arnold and Hatch 1 failure-to-start from failures of equipment other than the injection valve (FTSO) probabilities were found to be significantly higher than the values used in the PRA/IPEs, and are the highest failure probabilities of all plants considered. The plant-specific FTSO probabilities for the remainder of the industry were in general agreement with the probabilities used in their respective PRA/IPE.

The mean failure-to-start due to the injection valve (FTSV) probability based on industry experience was a factor of 10 or more higher than the values from 10 plant PRA/IPEs. This may be due to using MOV failure rates based on failures of MOVs in a wide range of applications rather than for the specific application in which the MOV is used in the HPCI system. For example, the Quad Cities plant-specific value used in the PRA/IPE was calculated based on MOV data from several systems, of which 46 MOV failures were observed out of 31,652 demands. It is unlikely that there were 31,652 demands of MOVs to operate under conditions similar to those present during an unplanned demand of the HPCI system.

Thirteen plants were found to have mean failure-to-run (FTR) probabilities that were higher than the PRA/IPE value by a factor of 10 or more. The Peach Bottom PRA/IPE (Peach Bottom is not one of the thirteen) suggests a likely cause of this problem. Specifically, it is noted that generic pump failure-to-run numbers in the Accident Sequence Evaluation Program (ASEP) database (a commonly used generic database) were based on plant operational hours, not pump operational hours. If the generic ASEP FTR is recalculated (as in the Peach Bottom PRA/IPE) based on actual pump run time, the resulting generic value is similar to the Peach Bottom plant-specific value of 0.0053 per hour, yielding 0.026 to 0.13 for a typical 5 24 hour mission. These values bracket the FTR based on plant-wide experience and are large compared to the full mission FTR values of 0.001 to 0.0062 used by the 13 plants showing notable differences.

Table 5. PRA/IPEs having basic events probabilities that differ from industry experience.

Plant	FTSO	FTSV	FTR	MOOS
Browns Ferry 2			X	
Brunswick 1 & 2		X	X	
Dresden 2 & 3		X	X	
Duane Arnold	X		X	
Fermi 2			X	
FitzPatrick			X	
Hatch 1	X	X		
Hatch 2		X		
Hope Creek			X	
Pilgrim		X		
Quad Cities 1 & 2		X	X	
Susquehanna 1 & 2			X	
Vermont Yankee		X		

3.3 Additional PRA Insights

Two insights were gained as a result of reviewing the PRA/IPEs to develop plant-specific values of HPCI system unreliability and to extract the basic events failure probabilities. First, it was found that most of the PRA/IPEs do not model the HPCI system in the way it is commonly operated. Specifically, the maintenance of level following initial injection, which places extra demands on the hardware and operators, is either not modeled or, if modeled, does not include the risk-important basic events. Second, even those PRA/IPEs that do model the system more rigorously do not reflect the impact of such operation on the hardware; i.e., the failure probabilities associated with injection valve operation do not correspond with operational experience.

The major responses upon initial demand for the HPCI system include: opening of the steam isolation valve to the HPCI turbine; starting of the lubrication/hydraulic oil system pump; opening of the turbine stop and governor valves, which brings the turbine up to speed; and the opening of the injection valve. At this point, the HPCI system is injecting water into the RPV in a continuous fashion. The HPCI design flow, which is based on conservative licensing assumptions, exceeds the flow requirements for the majority of actual HPCI demands based on operating experience. As a result, in order to control level shortly after the beginning of most events, the HPCI system must be placed in manual control and the flow diverted to either the torus or back to the suction source (likely the condensate storage tank). If such action is not taken quickly, the system will automatically trip on high level. If the automatic trip fails and the operator does not take manual control, then the reactor system will overfill, water will enter the main steam line and subsequently the HPCI turbine. When this happens, the turbine is assumed to be lost for the remainder of the event.

Placing of the HPCI system in manual control requires various operator actions and numerous hardware responses. From a hardware perspective, cycling of the injection valve and test line MOV and manual speed control of the turbine is required. If manual control of the turbine is not used or is not available, the turbine must be secured (tripped) and/or the injection valve must be completely shut. As the RPV level falls, the HPCI system must be realigned or restarted.

Eleven PRA/IPEs model operator actions to control RPV level. Restart of tripped or secured turbine-driven pumps is also considered by eight PRA/IPEs. However, only two model the hardware associated with the turbine speed controller or the injection valve; thus, the first insight is that most PRA/IPEs do not model the HPCI system in the way it is commonly operated during an event. A summary of the modeling approach for 20 PRA/IPEs is shown in Table 6. (The modeling for the other three PRA/IPEs considered in this report did not contain the necessary information to be included in the summary).

For the two PRA/IPEs that do model the hardware associated with manual control of the HPCI system, the failure probabilities used for cycling of the injection valve are on the order of 0.001. Plant experience indicates that three failures of the injection valve occurred out of approximately 19 mission demands to reopen, resulting in a failure probability of 0.20 (see FRO in Table 2). The difference in failure rate is a factor of 200; thus, the second insight is that even those PRA/IPEs that do model the system more rigorously do not reflect the impact of such operation on the hardware. The effect is quite large. The system unreliability assuming a single injection, based on industry experience and including operator recovery actions, is 0.056 (Table 2). The addition of the FRO mode in the fault tree model results in a system unreliability of 0.24, an increase of greater than a factor of 4. The 90% interval on this unreliability is (0.094, 0.44).

Table 6. Summary of PRA/IPE modeling of operator actions and hardware associated with manual control of HPCI.

Plant	Operator actions for manual control included in model?	Hardware modeled other than restart of pump
Browns Ferry 2	Yes	Models turbine flow controller
Brunswick 1 & 2	No	None
Cooper	Yes	None
Dresden 2 & 3	Yes	None
Duane Arnold	No	None
Fermi 2	Yes	None
FitzPatrick	No	Models restart of lube oil pump and reopening of steam and injection valves
Hatch 1 & 2	Yes	None
Hope Creek	Yes	None
Peach Bottom 1 & 2	No	None
Pilgrim	No	None
Quad Cities 1 & 2	Yes	None
Susquehanna 1 & 2	No	None
Vermont Yankee	Yes	None

4. ENGINEERING ANALYSIS OF THE OPERATIONAL DATA

This section documents the results of an engineering evaluation of the HPCI operational data derived from LERs and the Accident Sequence Precursor (ASP) database. The objective of this analysis was to analyze the data and provide insights into the performance of the HPCI system throughout the industry and at a plant-specific level. Unlike the PRA assessment provided in Section 3, all LERs submitted during the evaluation period and the ASP events that mentioned the HPCI system were considered as part of this analysis; no data were excluded. The LER data used in this evaluation include the 240 HPCI system inoperabilities, of which 145 were classified as failures, and the 63 HPCI unplanned system demands. The ASP database contained 19 events related to a demand of the HPCI system; 7 identified a system malfunction during an unplanned demand, 8 were unplanned demands with no system malfunction, and 4 were potential demands of the system when it was out-of-service for maintenance/testing.

The results of the operational data review were:

- While the rate of HPCI system unplanned demands and failures per plant operational year decreased during the 7-year period, unreliability showed no significant trend.

- Unplanned demand failures dominated the contribution to HPCI system unreliability prior to 1991, and cyclic test failures dominated HPCI system unreliability from 1991 on. There were no observed unplanned demand failures after 1991.

- The component failures and their failure mechanisms observed during unplanned demands were different than those found during the performance of surveillance tests.

    - Component failures observed during unplanned demands were dominated by injection valve and turbine governor malfunctions. Malfunctions of the injection valve due to pressure locking were recovered in 1 out of 4 instances, while governor malfunctions that were a result of water in the steam lines and erratic operation under varying flow conditions were always recovered.

    - Component failures observed during the performance of surveillance tests were dominated by steam line MOV and turbine governor malfunctions. Malfunctions of the steam line MOV were the result of improper maintenance and thermal binding, and governor malfunctions were the result of contaminated oil, calibration anomalies, and hardware failures.

- Failures associated with instrumentation and control circuits occurred twice as often when the HPCI system was in standby than during surveillance tests, with no failures observed during unplanned demands.

    - The demand-related failures that were observed in these circuits only occurred during the performance of a surveillance test and not during an unplanned demand. These demand-related failures were predominantly the result of personnel error and procedural problems. Examples of these failures included; miscalibration of detectors and sensors which would have prevented or degraded system response during an unplanned demand,

and inadvertent shorting of relays and blown fuses that resulted in spurious trips of the containment isolation function of the system.

- The failures discovered when the system was in standby were primarily time-related failures. The types of time-related failures observed were; invertor failures, resistor and relay failures, and detector shorts from moisture intrusion. These time-related failures were identified by control room annunciators and other system indication available to control room operators.

X There was no correlation observed between the plant's low-power license date and the rate of failures per operational year.

The following subsections provide a comprehensive summary of the industry data supporting the above results as well as additional insights derived from: (a) an assessment of the operational data for trends and patterns in system performance across the industry and at specific plants, (b) identification of the subsystems and causes that contribute to the system failures, (c) a comparison of the failure mechanisms found during surveillance tests and unplanned demands, (d) evaluation of the relationship between system failures and low-power license date, and (e) Accident Sequence Precursor events involving the HPCI system.

4.1 Industry-wide Evaluation

4.1.1 Trends by Year

Table 7 provides the HPCI system inoperabilities, failures, and unplanned demands that occurred in the industry for each year of the study period. Figures 9, 10 and 11 are illustrations of inoperability, failure, and unplanned demand rates for each year of the study with 90% uncertainty intervals. Figures 10 and 11 include a fitted trend line and a 90% confidence band for the fitted trend. The rate is the number of events that occurred in the specific year divided by the total number of plant operational years for the specific year.

Table 7. Number of HPCI system inoperabilities, failures, and unplanned demands by year.[a]

Classification	1987	1988	1989	1990	1991	1992	1993	Total
Inoperabilities	38	31	39	35	31	22	44	240
Failures	26	18	22	23	21	13	22	145
Unplanned Demands	16	10	7	13	9	6	2	63
Cyclic Surveillance Test Demands	12	13	18	16	17	20	15	111
Plant Operational Years	15.0	14.3	15.9	18.29	17.8	17.6	17.9	116.6

a. Each entry consists of events that occurred that year. Shutdowns longer than two calendar days are excluded from the operating year.

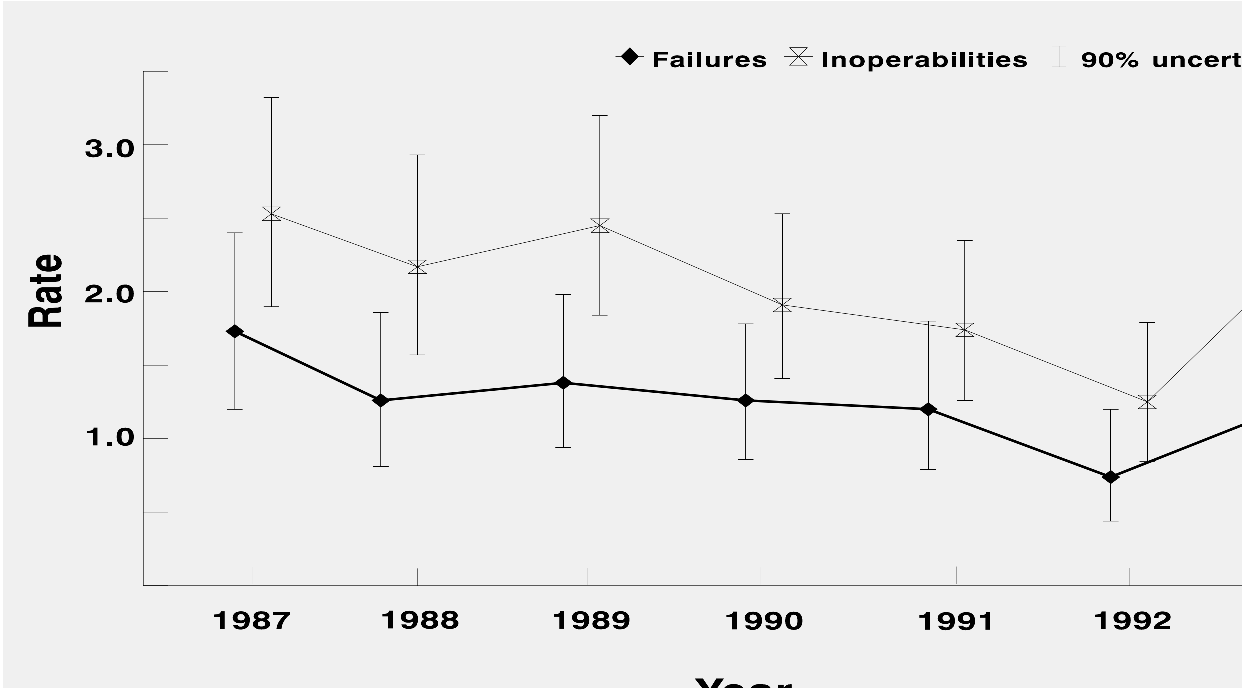


Figure 9. HPCI inoperabilities and failures per plant operational year, with 90% uncertainty intervals.

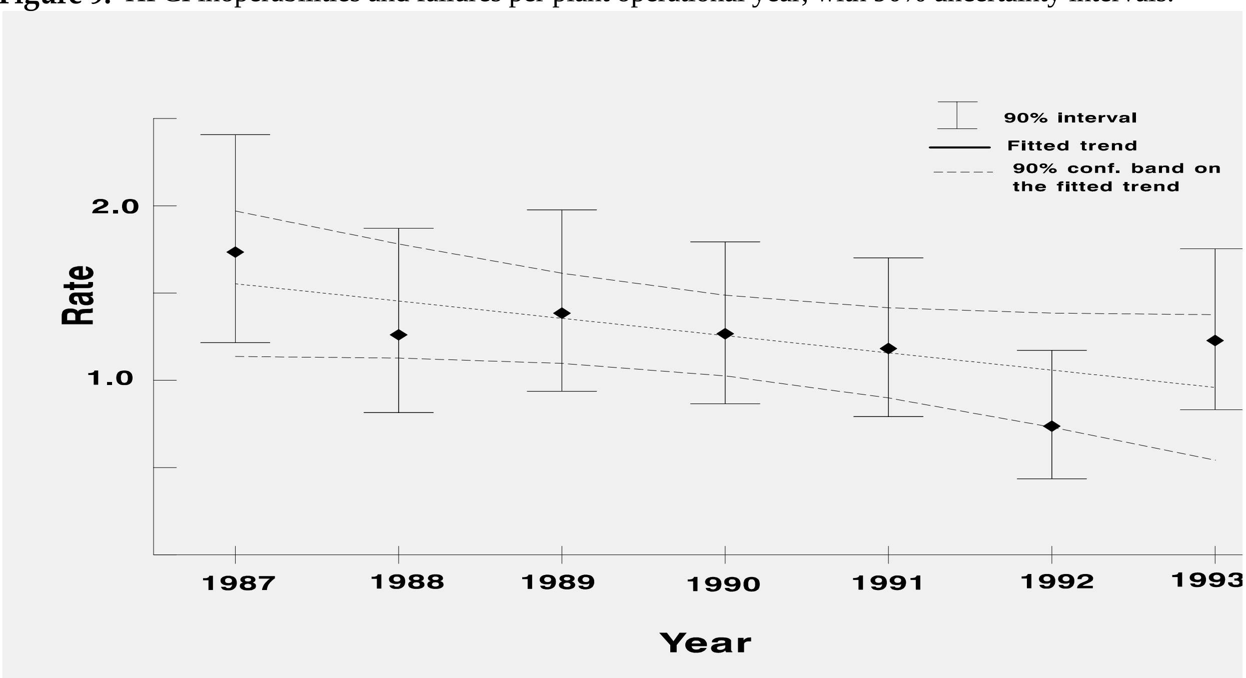


Figure 10. HPCI failures per plant operational year, with 90% uncertainty intervals and confidence band on the fitted trend. The trend is almost significant (P-value = 0.07).

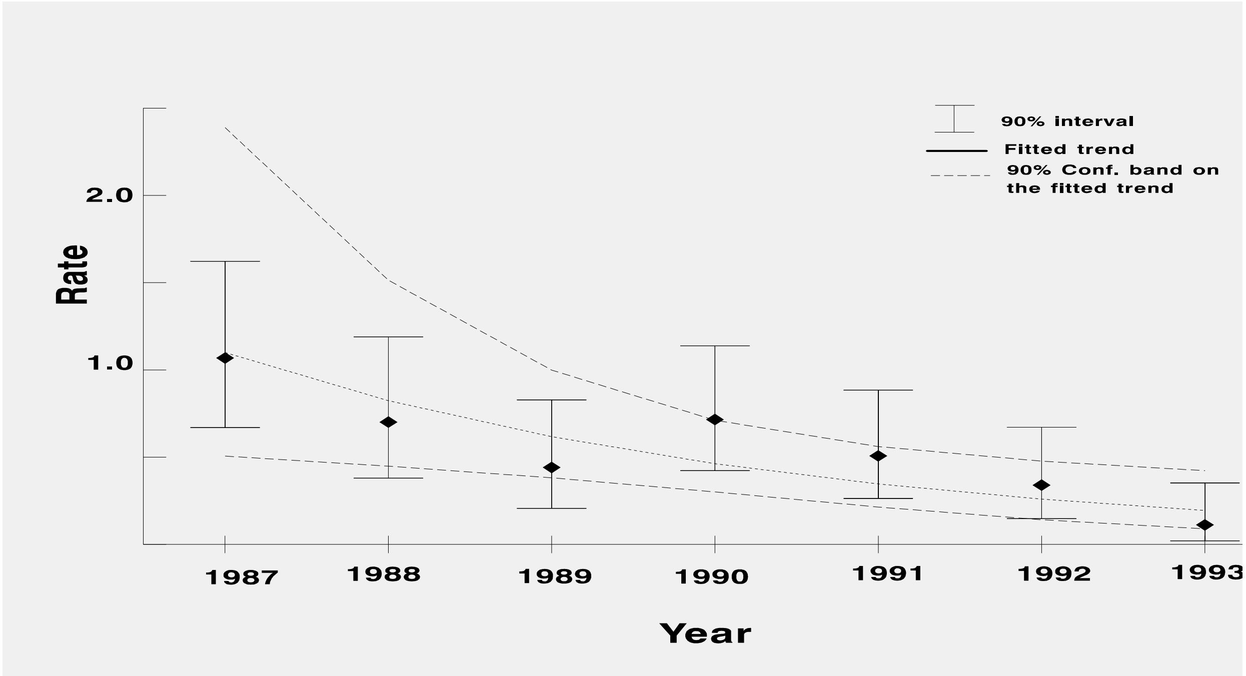


Figure 11. HPCI unplanned demands per plant operational year, with 90% uncertainty intervals and confidence band on the fitted trend. The trend is statistically significant (P-value=0.01).

Analysis of the inoperabilities and failure trends showed, in general, a decrease over the past 7 years. Analysis of the unplanned demands trend showed, a statistically significant, decrease over the past 7 years.

While the failure rate illustrated in Figure 10 shows a nearly significant decreasing trend (P-value = 0.07) and the unplanned demand rate illustrated in Figure 11 shows a significant decreasing trend (P-value = 0.01), the unreliability, presented previously in Figure 5, shows no significant trend (P-value = 0.29). To determine the mechanism that contributed to the relatively constant unreliability, an analysis of the HPCI demand and failure data was performed. The results of the demand and failure data analysis indicated the following:

- The demands prior to 1991 were approximately evenly distributed between cyclic surveillance tests (59) and unplanned demands (46). From 1991 on, there were three times the number of cyclic surveillance test demands (52) than unplanned demands (17).

- The failures prior to 1991 were experienced approximately 3 times as often on unplanned demands (13) as cyclic surveillance tests failures (4). From 1991 on, there were significantly more cyclic test failures (8) than unplanned demand failures (1).

Thus, the unplanned demand failures dominated the contribution to HPCI system unreliability prior to 1991, and cyclic test failures dominated HPCI system unreliability from 1991 on, with a net result of a constant HPCI system unreliability. A review of the subsystems and components contributing to system unreliability is discussed in the following subsection.

4.1.2 HPCI Subsystem Failures

The HPCI subsystems that failed or contributed to the HPCI system failures and inoperabilities were reviewed. The percentages of failures and inoperabilities caused by each subsystem were approximately the same; therefore further analysis only focused on the failures. Table 8 summarizes the percentage of the total number of HPCI system failures for each subsystem, for each method of discovery.

As indicated in Table 8, failures that occurred during unplanned demands were split between the turbine and turbine control valves subsystem and the coolant piping and valves subsystem, with no failures attributed to the instrumentation and control subsystem. During surveillance tests, the turbine and turbine control valves accounted for about the same percentage as during unplanned demands;

Table 8. Subsystem contribution to HPCI system failures, by method of discovery.

Subsystem	Method of discovery		
	Unplanned demand	Surveillance test	Other
Turbine and Turbine Control Valves	58%	61%	32%
Instrumentation and Control	0%	28%	60%
Coolant Piping and Valves	42%	11%	8%

however, instrumentation and control subsystem failures were observed, and they were more dominant than the failures observed in the coolant piping and valves subsystem. Failures that were found other than during the performance of a surveillance test or unplanned demand were dominated by the instrumentation and control subsystem.

The unplanned demand failures associated with the turbine and turbine control valves subsystem primarily occurred prior to 1991 (only one failure occurred from 1991 on), while surveillance test failures were approximately evenly distributed throughout the study period. Failures associated with the coolant piping and valves subsystem found during the performance of surveillance tests were approximately evenly distributed throughout the study period, however, all unplanned demand failures occurred prior to 1991.

Failures associated with the instrumentation and control subsystem varied from year-to-year, with no specific trend in the number of failures that occurred in any one year or over the study period. The failures associated with this subsystem occurred twice as often when the HPCI system was in standby than during a demand (surveillance test or unplanned). The demand-related failures that were observed in this subsystem only occurred during the performance of a surveillance test and not during an unplanned demand. These demand-related failures were predominantly the result of personnel error and procedural problems. Examples of these failures included; miscalibration of detectors and sensors which would have prevented or degraded system response during an unplanned demand, and inadvertent shorting of relays and blown fuses that resulted in spurious trips of the containment isolation function of the system.

Analysis of the failures discovered by other means in the instrumentation and control subsystem indicated that the observed failures were primarily time-related failures when the system was in standby and not demand-related failures. This observation is the result of the subsystem being normally in continuous operation (energized). The types of time-related failures observed in this subsystem were component malfunctions that included; invertor failures, resistor and relay failures, and detector shorts from moisture intrusion. These time-related failures were identified by control room annunciators and other system indication available to control room operators.

To further analyze the subsystem failures, the components that caused the subsystem to fail were reviewed. The failures were characterized by over forty specific HPCI component failures. Although these component failures were diverse, seven components accounted for over half of the inoperabilities and failures. These seven components were the auxiliary oil pump, injection valve, flow controller, turbine governor, isolation logic, inverter, and steam-line motor operated valve. The percentage of components causing both the inoperabilities and failures were about the same; therefore further analysis only focused on the failures. Table 9 summarizes the percentage of the total number of HPCI system failures for each method of discovery, partitioned by the seven components.

Three components, the auxiliary oil pump, governor, and injection valve, caused over 80% of the unplanned demand failures. The surveillance test failures were more diverse with three components, the auxiliary oil pump, governor, and steam line MOV, causing about 50% of the failures. The failures found other than during a demand (surveillance test or unplanned) were even more diverse with inverter failures being higher than the other components.

As shown in Table 9, failures experienced during unplanned demands were more likely to be failures of the injection valve and turbine governor than any other component. These two components comprised 66% of the unplanned demand failures, however, they were a significantly smaller contribution to surveillance test failures (21%). This appears to be a result of a difference in the way the HPCI system is called upon to operate during unplanned demands and how surveillance tests are performed. In surveillance tests, the HPCI turbine is not run for an extended period of time with varying flowrates, nor is the injection valve tested at rated pressures and flow rates. The technical specification requirements for the surveillance tests do not require flow to the vessel or the governor to function for an extended period of time with varying flowrates. During unplanned demands, the HPCI system generally responds to the initial event and is placed in a full-flow test mode for reactor vessel pressure control or for future injection needs. However, the injection valve was observed to fail in 20% of the subsequent injection attempts. This indicates that surveillance tests are finding problems associated with the system, however, there are a limited number of components (governor and injection valve) that are not fully tested in the manner in which they are operated during an unplanned demand. The data also show that the largest contributor to surveillance test failures is the steam line MOV and turbine governor, but there have been no steam line MOV failures during unplanned demands. In addition, during conditions other than unplanned demands and surveillance tests, inverter failures were the largest contributor to that discovery method, but they have not caused any failures during surveillance tests or unplanned demands.

Table 9. Component contribution to HPCI system failures, by method of discovery.

Component	Subsystem	Method of Discovery		
		Unplanned demand	Surveillance test	Other
Auxiliary oil pump	Turbine & Turbine Control Valves	17%	12%	4%
Turbine governor	Turbine & Turbine Control Valves	33%	17%	6%
Steam line MOV	Turbine & Turbine Control Valves	0%	20%	10%
Flow controller	Instrumentation & Control	0%	7%	10%
Isolation logic	Instrumentation & Control	0%	7%	6%
Inverter	Instrumentation & Control	0%	0%	18%
Injection valve	Coolant Piping & Valves	33%	4%	6%
Other		17%	33%	40%

Thus, the component failures observed during an unplanned demand were dominated by injection valve and turbine governor malfunctions, and the failures observed during the performance of surveillance tests were dominated by turbine governor and steam line MOVs malfunctions. Analysis of the mechanisms that contributed to the differences in component failures observed during and unplanned demand and surveillance tests indicated the following.

Governor problems experienced during an unplanned demand were caused by two mechanisms; (1) water in the steam lines, and (2) inappropriate needle valve adjustments. Water in the steam lines caused the turbine to overspeed and trip. Even though the governor reset automatically as designed during the unplanned demands, water in the steam lines was observed during the performance of a surveillance test to cause the turbine rupture discs to fail and discharge steam directly into the HPCI room. The steam discharge into the HPCI room resulted in a turbine isolation and a loss of the HPCI system. This type of loss of the HPCI system was only modeled or assumed to occur in a few of the PRA/IPEs reviewed for this study.

The inappropriate needle valve adjustment resulted in erratic operation of the governor which, in turn caused flow oscillations. These flow oscillations were readily identified and recovered by plant operators by taking manual control of the system. The needle valve was adjusted properly for the steady-state surveillance test flow requirements; however, this adjustment was not adequate to prevent the erratic operation governor response under the varying flow rates experienced during an unplanned demand. A review of several emergency operating procedures indicated that taking manual control of the governor during the execution of an emergency operating procedure was not typically considered.

Injection valve failures during an unplanned demand were observed to have occurred during subsequent injection attempts in 3 out of 4 injection valve failures. The failures of the injection valves were associated with the motor operators. Specifically, it appears that pressure locking of the valve occurred after the first injection attempt, and were not recovered. The other injection valve failure that occurred was the result of operator error and was quickly recovered.

The governor failures observed during the performance of a surveillance tests were varied and causes included calibration anomalies, malfunctions of the ramp-generator electronic modules that resulted in speed oscillations, contamination of the governor oil with water which resulted from steam leakage through the steam supply isolation valves, and electrical grounds and failures of the governor power supply drooping resistor. These were the same type of malfunctions identified in the AEOD Special Study (AEOD/S93-02), *Operating Experience Feedback Reliability of Safety Related Steam Turbine-driven Pumps.*[17] The dominant contributors to the governor failures during initial system start were water and foreign material in the oil that causes a turbine overspeed trip, and water in the steam lines overspeeding the turbine. As shown later in Table 10, FTS of the system was a dominant failure mode of the system during surveillance testing. Other turbine and turbine control subsystem malfunctions included failures of the steam inlet valve limit switches, dirty governor linkages, malfunction of the flow control units, and failures of the auxiliary oil pump.

The steam line MOV failures observed during the performance of surveillance tests were primarily the result of either improper maintenance or thermal binding of the valve internals. Examples of the improper maintenance include (1) improperly adjusted torque switches, (2) insufficient or improper lubricant, or (3) improper assembly of the valve internals. As a result of each of these failure mechanisms the steam line MOV failed to open, and in some cases the motor-operators were destroyed in attempts to open the valve. These steam line MOV failures were a significant contributor to the high percentage of FTS events observed during surveillance testing, and were modeled in the PRA/IPEs reviewed for this study as a significant contributor to the FTS basic event. Based on the failure mechanism and number of failures of this component found during the performance of surveillance testing tends to indicate that surveillance tests are detecting these failures prior to the failure affecting system response during an unplanned demand.

4.1.3 Operational Failures

The failure modes FTS and FTR (including FRO the cyclic operations of the injection valve) were partitioned by method of discovery to determine if a difference exists and to evaluate the differences. Table 10 provides the results of the data partition.

The review of these two failure modes, FTR and FTS, indicated that these failure modes contribute differently between the surveillance test failures and the unplanned demand failures. The FTS failure mode was dominant during surveillance testing. This failure mode was observed in 74% of the surveillance test failures. However, the dominant failure mode during an unplanned demand was FTR, which was observed in 55% of the unplanned demand failures. Moreover, on unplanned demands, all of the FTS events were recovered but only one FTR event was recovered.

Among the FTS surveillance test failures, equipment problems associated with the turbine and turbine control subsystem were the most significant contributor. These failures were the same type of failures observed during the unplanned demands, and of the type that is expected during a cold quick start of the system. This would indicate that surveillance testing of the HPCI turbine closely mimics the stresses that the turbine would observe during an unplanned demand.

Among the FTR unplanned demand failures, equipment problems associated with the system MOVs (primarily injection valve) were the most significant contributor. However, MOV failures did not account for a significant number of the surveillance test failures. The MOV failures occurred during subsequent injection, as discussed in Section 3.3., and reflect HPCI system failure in a mode of operation that differs considerably from the manner in which surveillance tests are conducted. Surveillance tests require the MOVs to be opened, but do not require repeated cycling.

Table 10. Failure modes partitioned by method of discovery.

	Method of Discovery		
Failure mode (exclude MOOS)	Unplanned demand	Surveillance test	Other
Fail-to-start	45%	74%	87%
Fail-to-run	55%	26%	13%

4.2 Plant-specific Evaluation

Table 11 shows the following information for each plant: operating years, number of inoperabilities, the number of failures, the number of unplanned demands, and the rate of failures and of unplanned demands. As used here, a *rate* is simply an event count divided by the number of operating years.

The failure rates and unplanned demand rates are plotted in Figure 12. In each plot, the plants are listed from the highest to lowest rate. For each plant, the point estimate is shown with the 90% confidence interval. For any plant whose confidence interval lies entirely to the right of the industry average, shown by the vertical dashed line, the corresponding entries in Table 10 are shown by an asterisk. Note that 60% (38 of 63) of the unplanned demands for HPCI occurred among 4 of the 23 units (Brunswick 2, Hatch 1 and 2, and Hope Creek).

Because the plants with high failure rates do not necessarily have high demand rates, Figure 13 shows the two rates plotted on the two axes of one graph. The points that are far from (0, 0) in this graph are labeled with the plant name. Points in the lower left are not labeled, to prevent clutter. Any point in the upper right of the graph corresponds to a plant with both a high failure rate and a high rate of unplanned demands.

Table 12 provides the number of inoperabilities, failures, and demands for each plant per year over the evaluation period. Fourteen of the twenty-three plants had at least one year with high numbers of inoperabilities, failures, or unplanned demands including: Brunswick 1 and 2, Dresden 2 and 3, Duane Arnold, Hatch 1 and 2, Peach Bottom 3, Pilgrim, and Quad Cites 1 and 2. Each of these plants are discussed below.

Brunswick 1 and 2 have had a relatively high and consistent number of the inoperabilities and failures, between 1987-1991, as compared to the industry. Since then both units were shutdown most of the period and have reported no HPCI events. At both units reoccurring MOV problems dominated the system failures. At Brunswick 1 the MOV failures were experienced primarily in the steam supply lines to the turbine, and at Brunswick 2 the MOV failures were experienced with the injection valve. Many of the MOV failures were a result of thermal binding problems or motor insulation breakdown. Unit 1 has had only one unplanned demand, while Unit 2 has had a high number of unplanned demands (10) and four failures occurred during unplanned demands.

Dresden 2 has had several years (1987, 1988, 1989 and 1993) with a high number of inoperabilities; however, only a few of these inoperabilities were considered to be failures. Dresden 2 had no unplanned demands. Dresden 3 had performance similar to Unit 2. The HPCI system inoperabilities reported at both units throughout the study period were diverse and caused by unrelated problems. Examples of the

Table 11. HPCI inoperabilities, failures, and demands differentiated by plant.

Plant name	Operating years	Inoperabilities	Failures	Failure rate	Demands	Demand rate
Browns Ferry 2	2.25	2	2	0.89	0	0.00
Brunswick 1	3.83	15	10*	2.61*	1	0.26
Brunswick 2	4.59	17	11*	2.40*	10*	2.18*
Cooper	5.64	5	2	0.35	5	0.89
Dresden 2	5.09	18	2	0.39	0	0.00
Dresden 3	5.42	15	3	0.55	1	0.18
Duane Arnold	5.63	11	9	1.60	2	0.36
Fermi 2	5.55	11	9	1.62	2	0.36
FitzPatrick	4.49	15	8	1.78	3	0.67
Hatch 1	5.89	10	9	1.53	10*	1.70*
Hatch 2	5.97	9	8	1.34	9*	1.51*
Hope Creek	6.15	9	6	0.98	9*	1.46*
Limerick 1	5.70	7	5	0.88	0	0.00
Limerick 2	3.85	9	8	2.08	0	0.00
Monticello	6.28	4	2	0.32	2	0.32
Peach Bottom 2	3.97	13	7	1.76	1	0.25
Peach Bottom 3	3.54	14	11*	3.11*	4	1.13
Pilgrim	3.85	11	4	1.04	1	0.26
Quad Cities 1	5.53	15	8	1.45	0	0.00
Quad Cities 2	5.44	14	8	1.47	0	0.00
Susquehanna 1	5.67	7	6	1.06	1	0.18
Susquehanna 2	6.05	6	5	0.83	1	0.17
Vermont Yankee	6.22	3	2	0.32	1	0.16
Industry	116.61	240	145	1.24	63	0.54

a. Asterisk values correspond to rates that are approximately ∃2 times industry average.

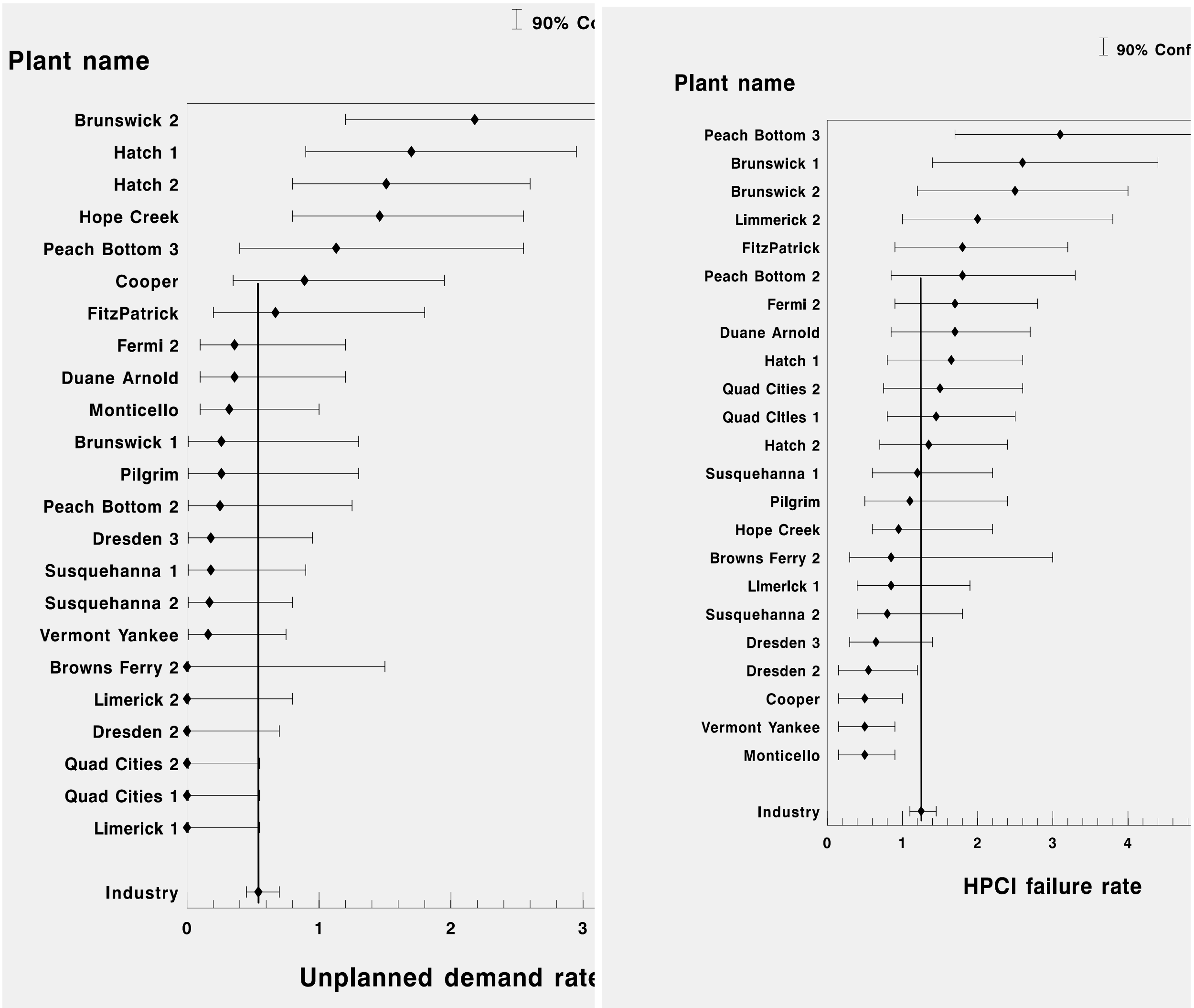


Figure 12. Plant-specific HPCI system unplanned demand and failure rates.

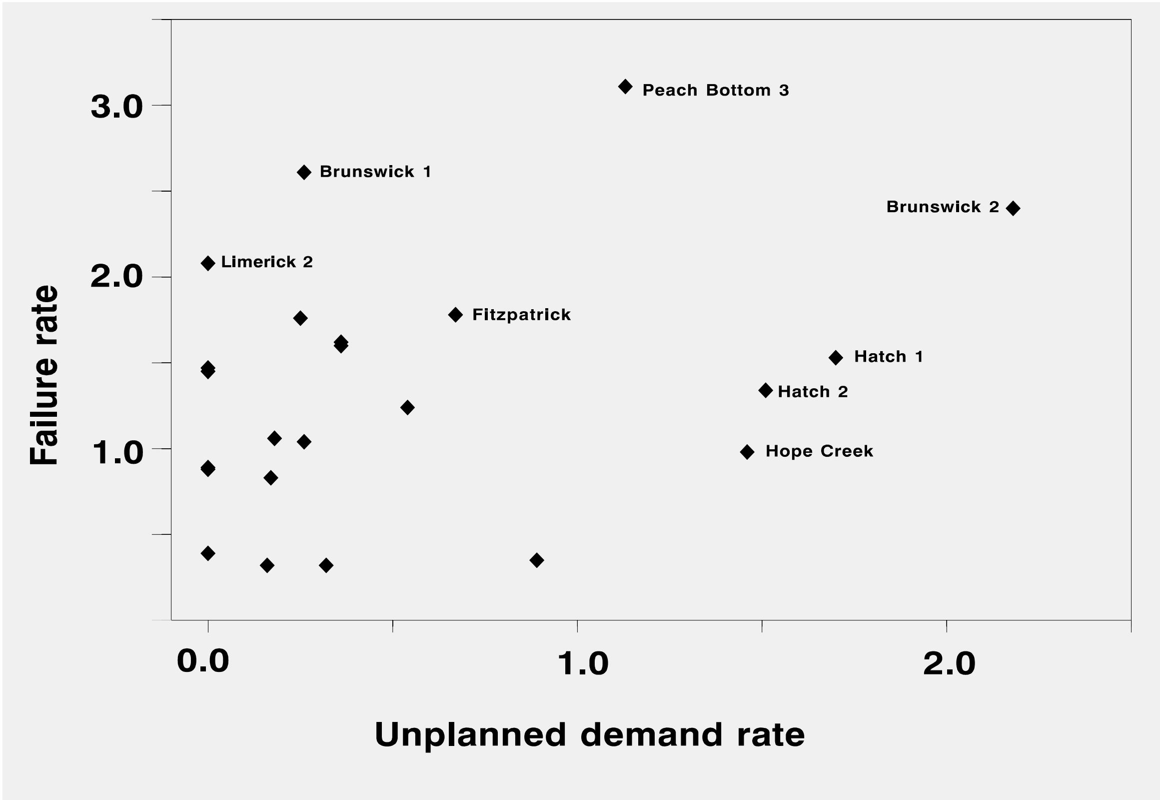


Figure 13. HPCI system plant-specific failure rates versus unplanned demand rate.

Table 12. Plant-specific HPCI events by year.

	1987			1988			1989			1990			1991			1992			1993		
	I	F	D	I	F	D	I	F	D	I	F	D	I	F	D	I	F	D	I	F	D
Browns Ferry 2 (260)	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	1	1	0	1	1	0	0	0	0
Brunswick 1 (325)	2	2	0	6	4	0	2	1	0	3	2	0	2	1	1	0*	0*	0*	0*	0*	0*
Brunswick 2 (324)	4	2	2	4	2	1	4	3	0	4	3	4	1	1	2	0*	0*	1*	0	0	0
Cooper (298)	0	0	2	1	0	1	0	0	1	0	0	1	0	0	0	2	1	0	2	1	0
Dresden 2 (237)	3	1	0	3	1	0	4	0	0	1	0	0	0	0	0	2	0	0	5	0	0
Dresden 3 (249)	4	1	0	0	0	0	2	0	1	0	0	0	0	0	0	4	0	0	5	2	0
Duane Arnold (331)	1	1	0	3	2	0	4	3	2	0	0	0	1	1	0	0	0	0	2	2	0
Fermi 2 (341)	0	0	0	2	2	1	1	0	0	2	2	0	3	2	0	1	1	1	2	2	0
FitzPatrick (333)	2	1	0	1	1	0	6	4	1	2	1	1	2	1	0	0*	0*	0*	2	0	1
Hatch 1 (321)	1	1	2	3	2	1	1	1	0	2	2	1	2	2	3	1	1	2	2	0	0
Hatch 2 (366)	3	3	4	1	1	2	0	0	1	3	2	1	0	0	0	0	0	1	2	2	0
Hope Creek (354)	1	1	4	1	1	3	2	2	0	3	1	2	0	0	0	0	0	0	2	1	0
Limerick 1 (352)	2	2	0	1	0	0	0	0	0	1	0	0	1	1	0	2	2	0	0	0	0
Limerick 2 (353)	0*	0*	0*	0*	0*	0*	2	1	0	2	2	0	2	2	0	2	2	0	1	1	0
Monticello (263)	2	1	1	0	0	0	2	1	0	0	0	0	0	0	1	0	0	0	0	0	0
Peach Bottom 2 (277)	2*	2*	0*	0*	0*	0*	3	2	1	2	1	0	2	0	0	1	1	0	3	1	0
Peach Bottom 3 (278)	1	1	0	0*	0*	0*	1	1	0	3	2	2	4	3	0	2	1	1	3	3	1
Pilgrim (293)	0*	0*	0*	0*	0*	0*	4	2	0	1	1	1	1	0	0	0	0	0	5	1	0
Quad Cities 1 (254)	4	2	0	1	0	0	1	1	0	1	0	0	1	1	0	2	1	0	5	3	0
Quad Cities 2 (265)	1	1	0	1	0	0	0	0	0	3	2	0	4	2	0	0	0	0	5	3	0
Susquehanna 1 (387)	2	1	0	2	2	0	0	0	0	1	1	0	2	2	1	0	0	0	0	0	0
Susquehanna 2 (388)	2	2	1	1	0	0	0	0	0	1	1	0	1	1	0	1	1	0	0	0	0
Vermont Yankee (271)	1	1	0	0	0	0	0	0	0	0	0	0	1	0	1	1	1	0	0	0	0
Total	38	26	16	31	18	10	39	22	7	35	23	13	31	21	9	22	13	6	44	22	2

* Plant shutdown > 70% of the year. I = Inoperabilities F = Failures D = Unplanned demands

HPCI related problems are: personnel error for incorrect installation of RPV level indicating switches, broken room cooler drive belts, inadvertent actuation of relays during testing, and loose trip reset switches.

Duane Arnold has had nine failures, primarily in 1988, 1989 and 1993, that were associated with turbine and turbine control valve subsystem, specifically the governor and steam line MOVs. The governor failures were malfunctions while starting the system (FTS), and were reoccurring problems in 1988 and 1989. These failures were also identified in Section 3.2 as resulting in a high unreliability estimate for the system.

Hatch 1 has had a consistent history over the entire evaluation period of having a few (1 to 3) inoperabilities, failures, and demands each year. The exception to this is 1993, when no events were reported. In addition, Hatch 1 was identified in Section 3.2 as having had a high FTS probability as compared to the plant-specific PRA/IPE probability for FTS. A review of the operational data indicated that governor problems that were recovered were the significant contributor to the high FTS probability. Hatch 2's HPCI performance has been more erratic than Hatch 1. Hatch 2 has had 2 to 3 inoperabilities and failures in 1987, 1990 and 1993, and nine unplanned demands have occurred over the evaluation period, with four of them occurring in 1987. The failures at Hatch 2 involved several different components, however, for both units failures associated with the MOVs throughout the system and the turbine governor are the most significant contributors to system failures. The causes of the component failures include, administrative problems with procedures and preventative maintenance, and personnel errors during performance of maintenance.

Peach Bottom 3 has had a consistently high number of inoperabilities, failures and demands since 1990. A review of the operational data since 1990 indicated that maintenance practices caused most of the inoperabilities and failures. These include administrative problems with procedures and preventative maintenance, and personnel errors during the performance of maintenance. Examples of the failures include two failures caused by insufficient spring force to reset the turbine governor due to administrative problems with procedures, two failures caused by a misaligned relay on the injection valve, and the failure to tighten the locking nuts resulting in low oil pressure and water in the exhaust line.

Pilgrim has had just two years with a high number of inoperabilities (1989 and 1993); however, only a few of these inoperabilities were considered to be failures. A review of the operational data for these years indicated several diverse and unrelated problems, such as an NRC Generic Letter 89-10 issue with the steam line outboard isolation valve, outdated and not revised wiring drawings, procedural problems, blown fuses in the flow controller, and a partially plugged HPCI flow orifice.

Quad Cities 1 has had only two years with high numbers of inoperabilities and failures (1987 and 1993). Quad Cities 2 has had three years of high numbers of inoperabilities and failures (1990, 1991, and 1993). No unplanned demands were reported in the operational data for either unit. A review of the operational data for these years indicated diverse and unrelated problems associated with the system at both units. Examples include excessive condensation in the turbine casing, late performance of check valve surveillance test requirements, trapped air in an instrument line, and a blown fuse in a logic circuit.

4.3 An Evaluation of HPCI Failures Based on Low-power License Date

To indicate how the passage of time affects HPCI performance, plant-specific total failures per operational year were plotted against the plant low-power license date. The failure rate for a plant was estimated as the (number of failures)/(number of plant operational years), with plant operational years estimated as described in Section A-1.3 of Appendix A. The rates and 90% uncertainty intervals are plotted in Figure 14. A fitted trend line, and 90% confidence band on the fitted line, is also shown in the figure. The trend is not statistically significant (P-value = 0.21).

A similar plot was made previously using unreliability (Figure 6). The conclusion is the same for both plots. The trend is not statistically significant.

4.4 Accident Sequence Precursor Review

The events identified by the ASP Program (NUREG/CR-4674) were reviewed. The purpose of this review was to relate the operational data to the types of events that resulted in a conditional core damage probability (CCDP) of greater than 1.0E-6. The search for ASP events was limited to the 1987-1993 study period, and included all ASP events in which the HPCI system was identified in the ASP database.

The search resulted in the identification of 19 events in which the HPCI system was mentioned. The number of events ranged from two events in 1987 to seven events in 1989, with no observed trend over the study period. These events occurred at 12 different plants. FitzPatrick and Brunswick Unit 2 each accounted for three events (15% each), Hatch Units 1 and 2 and Pilgrim each accounted for two events (10% each). The remaining seven events occurred at seven different plants.

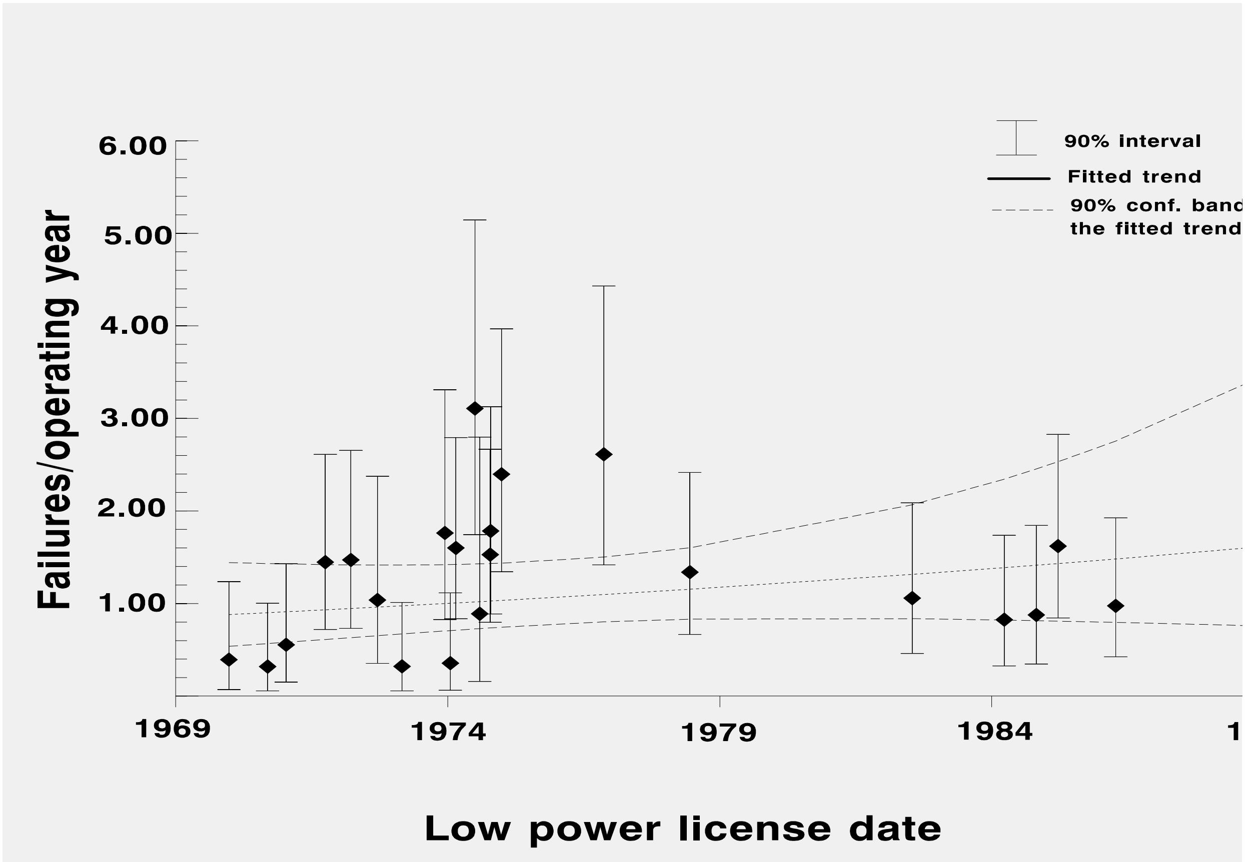


Figure 14. Failures per operating year, by plant, plotted against low-power license date. The trend is not statistically significant (P-value=0.21).

The 19 ASP events were each related to a demand of the HPCI system; 7 identified a system malfunction during an unplanned demand, 8 were unplanned demands with no system malfunction, and 4 were potential demands of the system when it was out-of-service for maintenance/testing. A brief description of the ASP events that identified a system malfunction during an unplanned demand are provided in Table 13. The ASP events that identified a HPCI unplanned demand without a system malfunction or a potential need of the HPCI system when it was out-of-service for maintenance or testing are listed in Table 14.

The ASP events that identified a demand and subsequent HPCI system malfunction had a CCDP that ranged from 1.0E-5 to 2.4E-4. The common element found in the ASP events for which the HPCI system malfunctioned was that the reactor core isolation cooling system (RCIC) system was unable to maintain RPV level, and a second control rod drive (CRD) pump had to be started to augment RCIC injection flow until restoration of normal feedwater occurred. These events are highlighted by three events in which failure of the injection valve occurred when the system was restarted or realigned for subsequent RPV injection.

The ASP events that identified a HPCI demand with no system malfunction had a CCDP that ranged from 3.1E-6 to 2.9E-4. Three of the ASP events indicated that the HPCI system was demanded to restore RPV level as a result of a loss of normal feedwater flow. Three of the ASP events involved use of the HPCI system only in the pressure control mode, and the remaining two of events were only partial actuations of the HPCI system, with no injection into the reactor vessel.

The four ASP events in which the system was unavailable because of maintenance were directly associated with a safety relief valve (SRV) actuation. The SRV actuations occurred during performance of a surveillance test that fulfilled the requirements of the limiting condition for operation (LCO) action statement for the HPCI system unavailability; because the HPCI system was unavailable, the SRVs were tested, which created a potential need for HPCI. In two of the three events involving SRV actuations, the SRV either failed open (short duration 5 seconds) or was inadvertently opened. The other SRV actuation event resulted in a high flux reactor scram when a SRV was cycled open. Even though during the SRV actuation events the HPCI system was not available, the RCIC system was available and was used for RPV water level control. However, the potential did exist that if an SRV failed open (unrecovered), the RCIC system would not have been able to maintain RPV water inventory.

Table 13. Summary of the ASP events in which a HPCI malfunction was identified during an unplanned demand.

Plant name	LER number	Event date	CCDP	Description
Brunswick 1	32591018	07/18/91	6.0E-5	A loss of feedwater resulted in a reactor scram. HPCI was used to restore RPV level. An oil leak was subsequently found that would only allow for the system to operate for 45 minutes.
Brunswick 2	32487001	01/05/87	2.4E-4	A turbine trip resulted in a reactor scram and SRV actuations to limit RPV pressure. HPCI was started to control RPV level. When level was restored, HPCI was aligned for RPV pressure control. During a subsequent need for RPV level restoration the HPCI injection valve failed to open. Both CRD pumps and RCIC were used to restore RPV levels.
Brunswick 2	32487004	03/11/87	1.0E-5	A loss of feedwater resulted in a reactor scram. HPCI auto-started to restore RPV level. When level was restored, HPCI was aligned for RPV pressure control. During a subsequent need for RPV level restoration the HPCI injection valve would not reopen as a result of thermal binding. The valve motor operator was damaged in attempts to open the valve.
Dresden 3	24989001	03/25/89	1.3E-5	A loss of offsite power caused a turbine trip and reactor scram. HPCI was manually started for RPV level control. An operator did not complete the procedure for manually starting HPCI, resulting in no lube oil cooling. While investigating and resolving the high bearing oil temperature, HPCI tripped on high RPV level.
Hatch 1	32191001	01/08/91	1.1E-5	A loss of offsite power resulted in a reactor scram. HPCI was actuated to restore RPV level, but operated erratically due to a failed speed controller. Turbine bypass valves were used to control RPV pressure.
Hatch 2	36690001	01/12/90	6.0E-5	A false low condenser vacuum signal resulted in a reactor scram. SRVs automatically opened to limit RPV pressure and HPCI auto-started to restore RPV level. Subsequently, HPCI tripped on high RPV level. With continued cycling of the SRVs to limit RPV pressure, the level was reduced to the HPCI auto-start setpoint. However, the injection valve would not reopen due to a failed overload relay for the motor operator. Both CRD pumps and RCIC were used to maintain RPV level.
Pilgrim	29390013	09/02/90	8.4E-5	A failure in the feedwater control system caused the operators to manually scram the reactor. HPCI was manually started for level control. The HPCI turbine tripped during the start; however, it automatically reset and HPCI was started successfully. Flow oscillations were noted during the 2 minutes of operation. HPCI was later started for pressure control. Again, the turbine tripped during the start, but automatically reset and started. Flow oscillations were again noted and the system operated in manual control

Table 13. continued.

Plant name	LER number	Event date	CCDP	Description
				for the 3 hours it was required.

Table 14. Listing of the ASP events that identified a HPCI unplanned demand without a system malfunction or a potential need of the HPCI system when it was out-of-service for maintenance or testing.

Plant name	LER number	Event date	CCDP
Brunswick 2	32489009	06/17/89	3.6E-5
Dresden 2	23790002	01/16/90	3.1E-6
Dresden 3[a]	24989001	03/25/89	1.3E-5
Duane Arnold	33189003	04/04/89	6.5E-6
FitzPatrick[a]	33389003	03/06/89	6.5E-6
FitzPatrick[a]	33389020	11/05/89	1.3E-5
FitzPatrick[a]	33389023	11/12/89	1.3E-5
Hatch 1	32188018	12/17/88	1.5E-5
Hatch 2	36688017	05/27/88	2.0E-5
Limerick 2	35389013	12/11/89	1.5E-5
Pilgrim	29391024	10/30/91	1.2E-4
Vermont Yankee	27191009	04/23/91	2.9E-4

a. This ASP event was a potential demand of the system when it was out-of-service for maintenance/testing

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