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Reliability Study: High-Pressure Safety Injection System, 1987–1997 (DRAFT)

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ABSTRACT

The report documents an analysis of the performance of the High-Pressure Safety Injection (HPI) systems at 72 United States commercial pressurized water reactors. The study used the operating experience from 1987 through 1997 as reported in LERs as its source data. A risk-based analysis, based on fault tree models for the systems, was performed on the data to estimate the observed unreliability of HPI system. HPI system unreliability estimates are calculated for the industry as a whole and for the individual plants. An engineering analysis was performed to determine the dominant contributors to HPI system unreliability. An analysis of trends was also performed to provide additional insights on the HPI system performance. The unreliability results obtained from the operating experience based data were compared with unreliability estimates calculated using data provided in plant individual plant examinations and probabilistic risk assessments.

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EXECUTIVE SUMMARY

This report presents a performance analysis of High-Pressure Safety Injection (HPI) systems at 72 United States commercial pressurized water reactors (PWRs). The evaluation is based on the operating experience from 1987 through 1997, as reported in Licensee Event Reports (LERs). The objectives of the study are: (1) to estimate the system unreliability based on operating experience and to compare these estimates with the estimates using data from probabilistic risk assessments and individual plant examinations (PRA/IPEs); and (2) to review the operating data from an engineering perspective to determine trends and patterns seen in the data and provide insights into the failures and failure mechanisms associated with the operation of the HPI system.

This study used as its source data the operating experience from 1987 through 1997 as reported in LERs. The Sequence Coding and Search System (SCSS) database was used to identify LERs for review and classification for this study. The reportability requirements of 10 CFR 50.73 (LER rule) were not used to define or classify any events used in this study. The full text of each LER was reviewed by an U.S. commercial nuclear power plant experienced engineer from a risk and reliability perspective.

The HPI system unreliabilities (injection phase only) were estimated using a fault tree model to associate event occurrences with broadly defined failure modes such as failure to start or failure to run. The probabilities for the failure modes were calculated by reviewing the failure information, categorizing each event by failure mode, and estimating the corresponding number of demands. Forty-seven plant risk reports (i.e., PRAs, IPEs, and NUREGs) were used for comparison to the HPI reliability results obtained in this study. These reports document HPI system information for 72 PWR plants.

The HPI system configurations (and operation) for the 72 plants used in this study differ considerably. HPI systems consist of different levels of pump train redundancy and diversity. To facilitate the assessment of the HPI systems, six HPI design classes were identified, and the plants were categorized accordingly.

Major Findings

Overall unreliability. Based on the 1987–1997 experience data, there were no failures of the entire HPI system identified in 224 unplanned system demands. System level fault tree models that use more detailed segment-level data and individual failure modes produce an unreliability of the HPI system of 4.5E-04 (calculated by arithmetically averaging the results of 72 plant-specific models).

Plant-specific results. Individual plant results vary by about a factor of fifty, from 6.0E-05 to 3.5E-03. The variability among the six HPI design classes largely reflects the diversity found in HPI system designs. The variability within design classes is attributed to the difference in design and operating characteristics rather than differences in plant-specific performance. The estimates of HPI unreliability using operating experience from LERs and fault tree analyses are plotted in Figure ES-1. Contributions to unreliability varied depending on the design and operation of the HPI system. Details for each class are provided in Section 3.2 of the report.

Dominant contributors to unreliability. Common cause failure (CCF) is the leading contributor to the HPI system unreliability. The importance of CCF is typical of redundant train systems that are highly reliable. Although there were no actual CCFs events identified in the unplanned SI actuations, there were CCF events identified in the 1987–1997 experience that occurred other than during an unplanned demand.

The dominant contributors to CCF were:

- Failures in HPI mini-flow lines,

- Hardware failures attributed to procedural or design flaws affecting redundant trains,

- Gas binding,

- Failed MOVs affecting the functionality of injection headers or suction path, and

- Level indication in suction tanks.

Comparisons to PRA/IPEs. The industry-wide arithmetic average of HPI system unreliability calculated using data (component failure probabilities, maintenance unavailability, etc.) extracted from PRA/IPEs is 5.8E-04. The corresponding estimate based on the 1987–1997 experience is 4.5E-04. A plot of these estimates is shown in Figure ES-2. PRA/IPE and operating experience estimates were generally comparable except for HPI Design Class 6.

For 50% of the Design Class 6 plants, the unreliabilities based on the IPE data are one or more orders of magnitudes lower than the unreliabilities calculated using operating experience. This difference is attributed to the low probabilities assigned to passive component failures such as the RWST in these IPEs.

Unplanned demand trend. Trends were identified in the frequency of the HPI unplanned demands, which includes both actual SI and inadvertent SI actuation. When plotted against calendar year, the unplanned demand frequency exhibited a statistically significant decreasing trend (Figure ES-3). Based on the fitted rate shown in Figure ES-3, the unplanned demand frequency for HPI for a population of 72 PWRs decreased from approximately 48 per year in 1987 to approximately 6 per year in 1997. This constitutes an improving trend in the frequency of events challenging the HPI system.

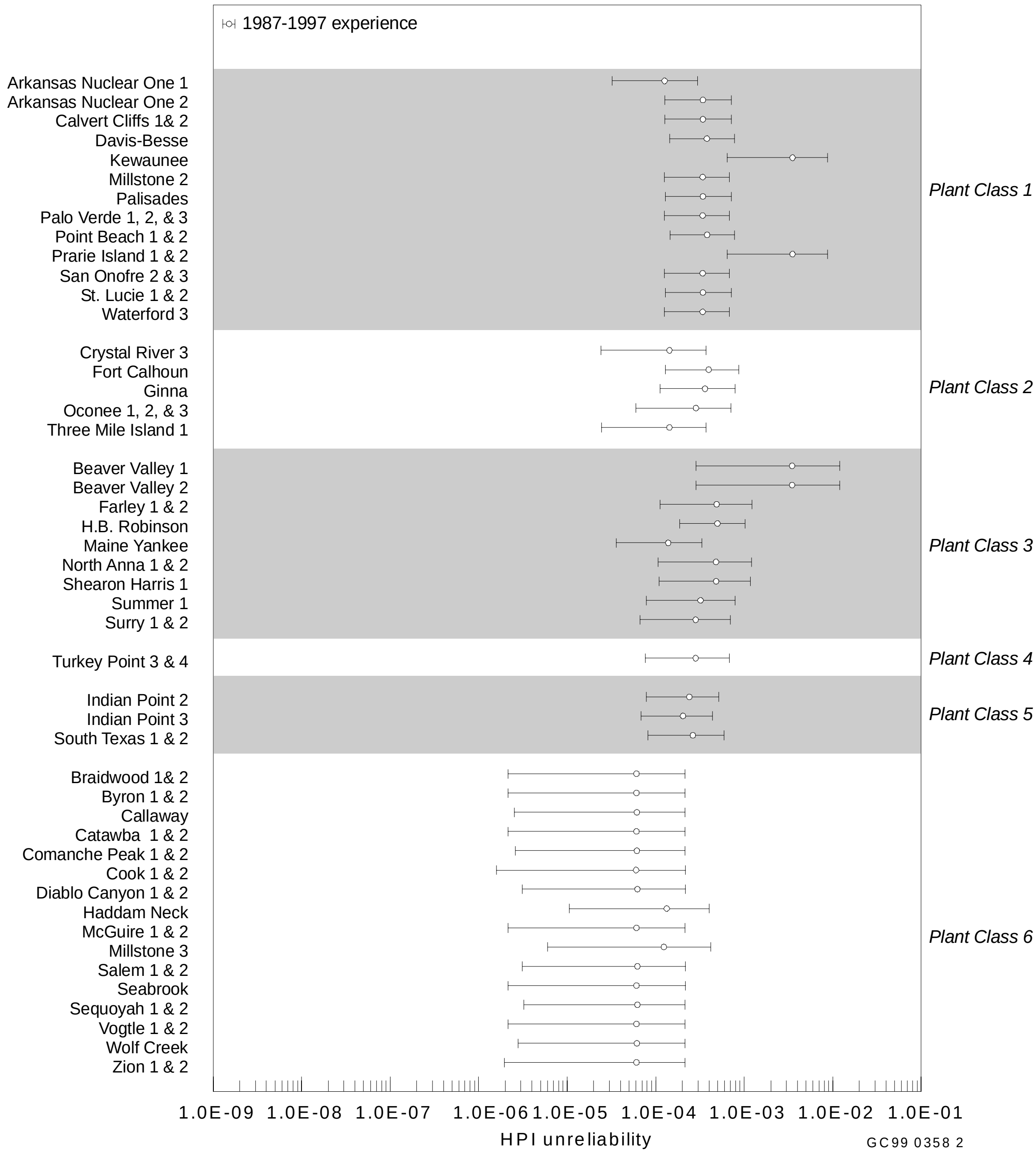

Figure ES-1. Plant-specific estimates of HPI system unreliability (injection phase only) grouped by design class. The mean and uncertainty values associated with this plot are listed in Table D-3 in Appendix D.

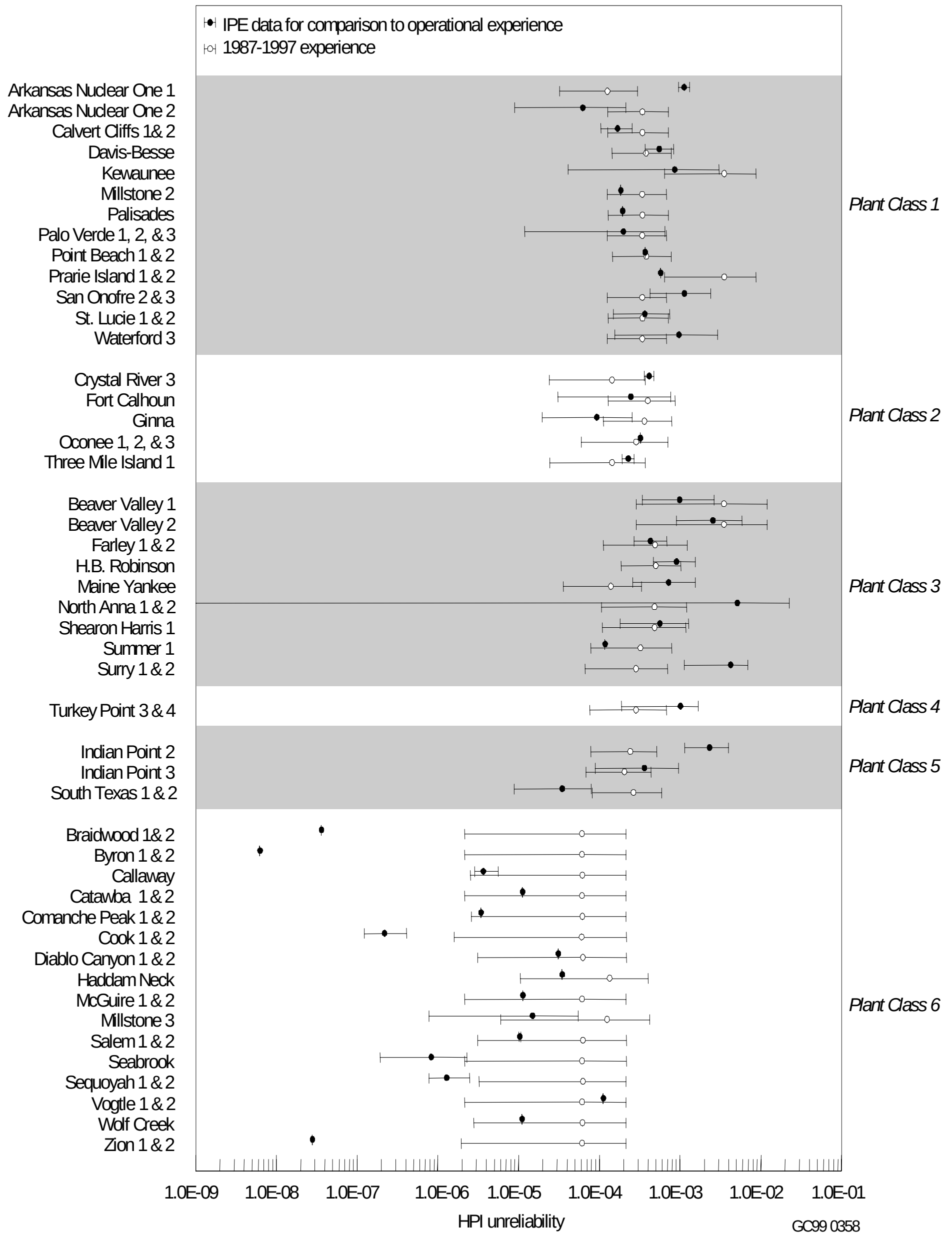

Figure ES-2. Plant-specific estimates of HPI system unreliability (injection phase only) grouped by design class. The mean and uncertainty values associated with this plot are listed in Table D-3 and D-4 in Appendix D.

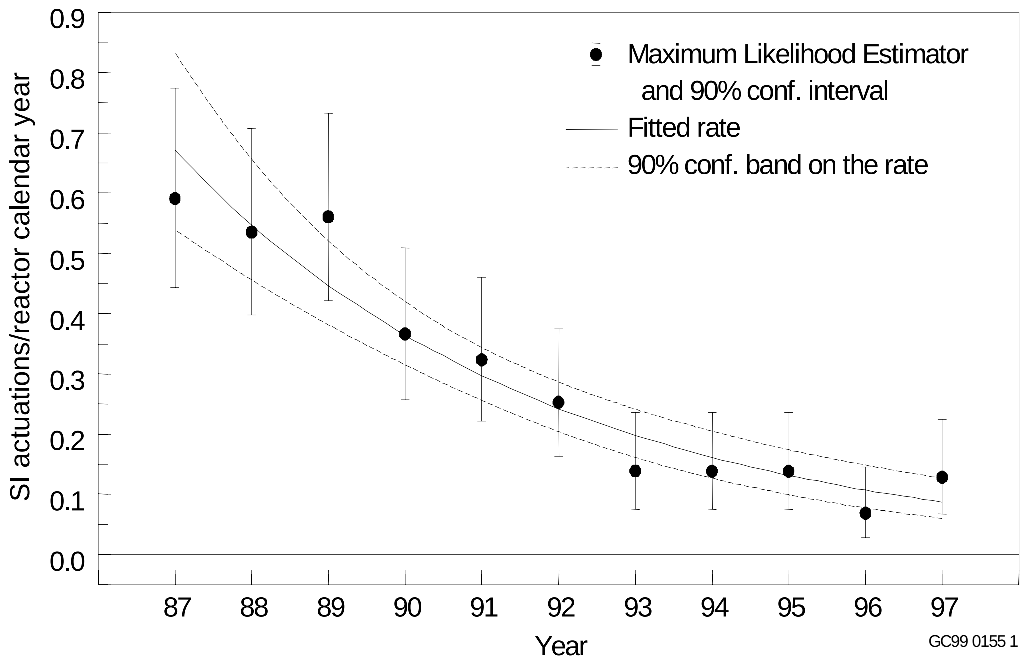

Figure ES-3. Frequency (events per reactor-calendar year) of all SI actuations, as a function of calendar year, calculated assuming that the frequency does not depend on plant age (low-power license date), with confidence limits on the individual frequencies. The decreasing trend is highly statistically significant (p-value is 0.0001).

When the frequency of HPI unplanned demands (both actual and inadvertent SI actuation) was modeled as a function of low-power license date, a statistically significant increasing trend was detected. Figure ES-4 is a plot of the unplanned demand frequency of SI actuation as a function of low-power license date. According to Figure ES-4, the frequency of unplanned demands for HPI of plants that were licensed recently, on the average, is expected to be higher than that of older plants. However, the absolute difference in the frequency was small. Based on the fitted rate shown in Figure ES-4, a plant that received a low-power license in 1967 can be expected to experience an unplanned HPI demand about once every 4 years. In comparison, a plant that received a low-power license in 1993 can be expected to experience an unplanned HPI demand once every 2½ years. Furthermore, the significance of this difference is limited since the frequency of total unplanned demands from all plants has been trending down yearly.

Failure trend. The frequency of failure events observed during unplanned demands and other detection methods such as testing were analyzed to determine trends. Figure ES-5 plots the HPI system failure frequency as a function of calendar year. A statistically significant decreasing trend was identified in the frequency of reportable failure events of the HPI system when modeled as a function of calendar year. Based on the fitted rate shown in Figure ES-5, the frequency of reportable failure events of the HPI system for a population of 72 PWRs decreased from approximately 18 per year in 1987 to approximately 7 per year in 1997.

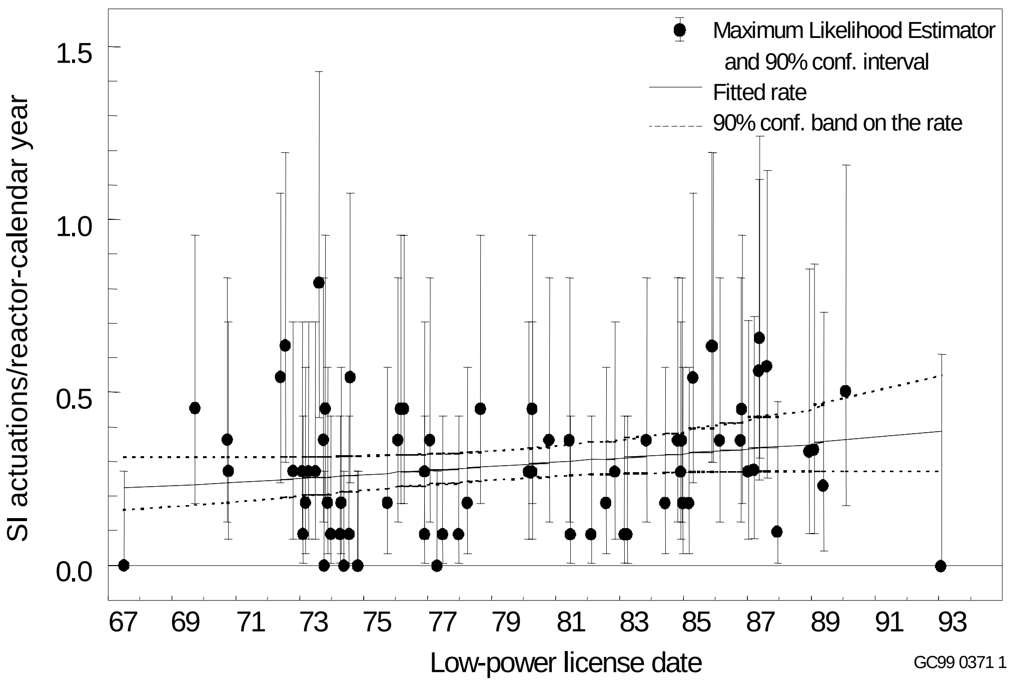

Figure ES-4. Frequency (events per reactor-calendar year) of all SI actuations, as a function of low-power license date. Each point corresponds to a single plant. The calculations for this figure ignore the effect of calendar year. The increasing trend in low-power license date is statistically significant (p-value is 0.01).

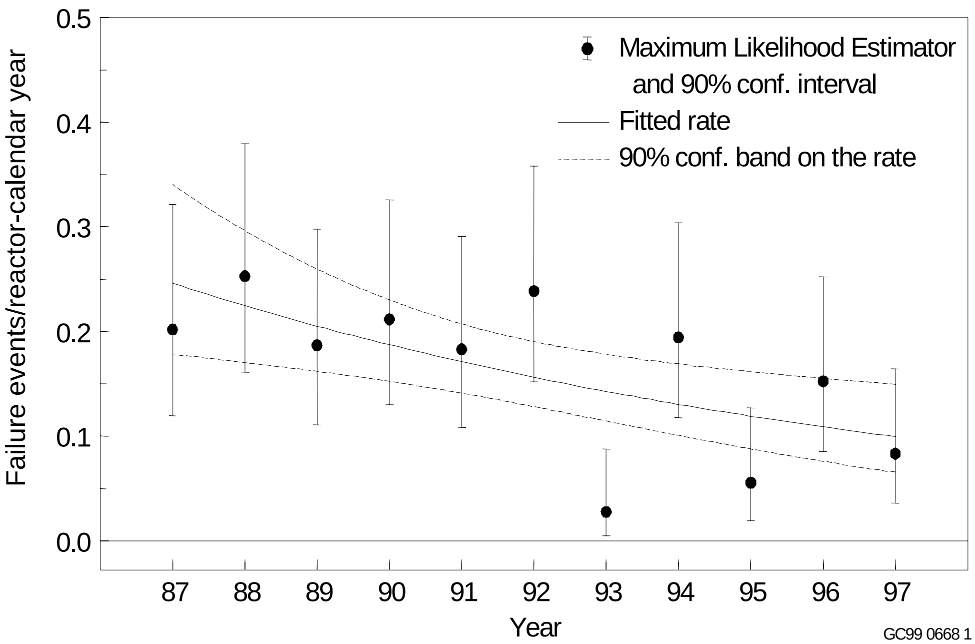

Figure ES-5. Frequency (events per reactor-calendar year) of all HPI failure events, as a function of calendar year. The calculations for this figure ignore the effect of low-power license date and plant-specific variation. The decreasing trend in year is statistically significant (p-value is 0.02).

A statistically significant decreasing trend was identified when the frequency of HPI failure events was modeled as a function of low-power license date. Figure ES-6 is a plot of the frequency of HPI failure events as a function of low-power license date. According to Figure ES-6, the frequency of reportable failure events of the HPI systems of plants that were licensed recently, on the average, is expected to be lower than that of older plants.

Based on the fitted rate shown in Figure ES-6, a plant that received a low-power license in 1967 can be expected to report a failure affecting HPI about once every 4 years. In comparison, a plant that received a low-power license in 1993 can be expected to report a failure affecting HPI once every 10 years. The significance of this difference is limited since the frequency of reportable failures from all plants has been trending down yearly. Furthermore, an examination of the nature of the failures associated with older versus newer plants showed that the observed trend is not indicative of aging.

Information Notices. The dominant contributor to HPI unreliability from the analysis of operating experience was CCF. A review of Information Notices issued between 1987–1997 relating to HPI failures showed that most of them (11 out of 14) were related to CCF events or conditions. The other Information Notices addressed cracks in HPI pipe welds and a single HPI train failure.

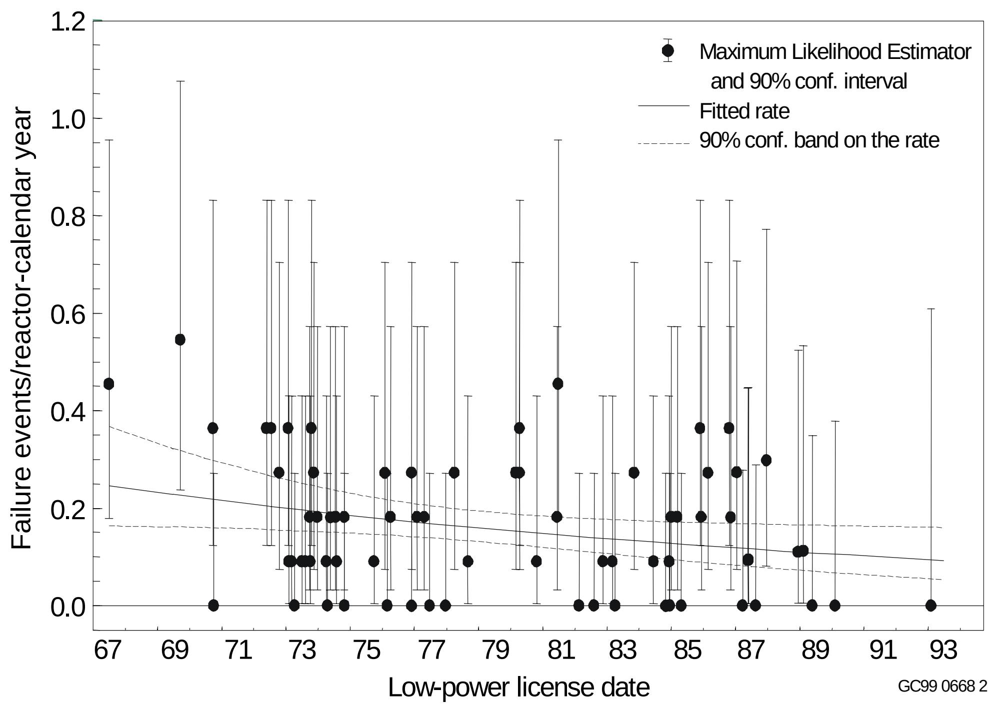

Figure ES-6. Frequency (events per reactor-calendar year) of all HPI failure events, as a function of low-power license date. Each point corresponds to a single plant. The calculations for this figure ignore the effect of calendar year. The decreasing trend in low-power license date is statistically significant (p-value = 0.026).

Accident Sequence Precursor Events. The dominant contributor to HPI unreliability from the analysis of operating experience was CCF. The more significant ASP events (conditional core damage probability greater than 1.0E-04) were also related to CCF of the HPI system. The ASP events of lesser significance (conditional core damage probability between 1.0E-04 and 1.0E-06) generally involved single train failures rather than CCF. This result is consistent with the results of the HPI unreliability analysis that indicated individual segment failures are not dominant contributors.

Data reporting. The HPI unreliability analysis and insights derived from the analysis were based on three HPI train failures that occurred during unplanned demands and 21 common cause failure events reported between 1987–1997. Failures affecting a single train of the HPI system are not reportable nor are demands such as surveillance tests. Therefore, the additional failure data and demands from events other than unplanned demands do not constitute an unbiased sample. Reporting of these failures and demands (such as that proposed for inclusion in EPIX) could enhance our ability to estimate HPI unreliability and derive insights from the operating experience for feedback to the regulatory programs.

FOREWORD

This report provides information relevant to high-pressure safety injection (HPI) system performance in response to normal operational transients and summarizes the event data used in the analysis. The results, findings, conclusions, and information contained in this and similar system reliability studies conducted by the Office for Nuclear Regulatory Research are intended to support several risk-informed regulatory activities. This includes providing information about relevant operating experience that can be used to enhance plant inspections of risk-important systems and information used to support staff technical reviews of proposed license amendments, including risk-informed applications. In the future, this work will be used in the development of risk-based performance indicators that will be based to a large extent on plant-specific system and equipment performance.

Findings and conclusions from the performance analysis of the HPI systems at 72 United States commercial pressurized water reactors based on 1987–1997 operating experience are presented in the Executive Summary. The results of the risk-based analysis and engineering analysis are summarized at the beginning of Sections 3 and 4. This report provides an industry-wide perspective on the reliability of HPI systems, and how both industry (generic) and plant-specific performance compares with reliability estimates derived from data in PRAs and individual plant examinations (IPEs). This report also provides an indication of how performance varies between plants and the measurable magnitude of that variation. The dominant contributors are identified along with information on important failure modes and causes. All relevant operating experience on common cause failures that have been identified has been compiled and generic common cause failure parameters have been estimated. A tabulation of failures, demands, and estimated failure rates for key equipment and system segments are also included. The report provides a mechanism for identifying individual licensee event reports (LERs) that are the source of the tabulated failure, demand, and failure-rate estimates. For convenience, the risk-important information that would be useful in support of risk-informed regulatory activities involving the HPI system is summarized in Table P-1. Users of this information are cautioned to be aware of the uncertainty in quantitative results when drawing inferences about industry performance trends and plant-specific variations in performance.

The application of results to plant-specific applications may require a more detailed review of the relevant LERs to determine specific aspects of the events associated with the dominant contributors that are applicable to a specific plant design and operational characteristics. Factors such as type of equipment, configuration variations, operating environment and conditions, and test and maintenance practices would need to be considered in light of specific information provided in the LERs cited in this report. This review is needed to determine if generic experiences described in the report are applicable to the design and operational features of the system at a specific plant. This is especially important for dominant failure modes associated with suction source reliability, starting reliability of pumps, and the running reliability of pumps in general. In addition, it may be appropriate to obtain and review more recent LERs to bring plant-specific insights on performance and the potentially important dominant contributors to a more current state. A search of the LER database can be conducted through the NRC's Sequence Coding and Search System (SCSS) to identify the system failures and demands that occurred after the period covered by this report. SCSS contains the full text LERs and is accessible by NRC staff from the SCSS home page (http://scss.ornl.gov/). Nuclear industry organizations and the general public can obtain information from the SCSS on a cost recovery basis by contacting the Oak Ridge National Laboratory.

The Office of Nuclear Regulatory Research plans to periodically update the information in this report as additional data becomes available.

Thomas L. King, Director
Division of Risk Analysis and Applications
Office of Nuclear Regulatory Research

Table P-1. Summary of risk-important information specific to HPI system unreliability.

Failure information from the 1987–1997 operating experience used to estimate system unreliability (event summaries, failure modes, and LER references)	Table C-1[a]
Dominant contributors to HPI system unreliability	Sections 3.2.2–3.2.5
Comparison of dominant contributors to HPI unreliability based on IPE failure probabilities and 1987–1997 operating experience for the six reference plants.	Table D-2
Causal factors affecting dominant contributors to HPI system reliability (affected segments and components, failure modes, cause of failures, methods of discovery, and LER references for all dominant events)	Sections 4.2, 4.3
Plant-specific failure data with LER references	Tables 2, B-2[a]
Plant-specific demand data with LER references	Tables 2, B-3[a]
Plant-specific estimates of HPI unreliability	Table D-3
System failure mode data and probability information	Table 4
Common cause failure parameters used for calculating system unreliability	Table 3

a. Other documents such as logs, reports, and inspection reports that contain information about plant-specific experience (e.g: maintenance, operation, or surveillance testing) should be reviewed during plant inspections to supplement the information contained in this report. These sources will provide updated information on plant operating experience including failure events and demands captured in plant logs that are not reportable in LERs, such as single train failures during tests.

ACKNOWLEDGMENTS

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Technical contributors to this report are J. B. Hudson and T. E. Wierman of the INEEL.

ACRONYMS

AMF	alternate minimum flow
ASEP	Accident Sequence Evaluation Program
ASP	accident sequence precursor
BIT	Borated-water Injection Tank
BWST	Borated Water Storage Tank
B&W	Babcock and Wilcox
CCDP	conditional core damage probability
CCF	common cause failure
CCP	centrifugal charging pump
CFR	Code of Federal Regulations
CL	cold water leg
CVCS	Chemical and Volume Control System
DRAA	Division of Risk Analysis and Applications (NRC)
ECCS	Emergency Core Cooling Systems
EOC	error of commission
ESF	engineered safety feature
ESFAS	Engineered Safety Feature Actuation System
FTR	failure to run
FTS	failure to start
FTO	failure to operate
HVAC	heating, ventilating, and air conditioning
HPI	High-Pressure Safety Injection
IHSI	Intermediate High-head Safety Injection
INEEL	Idaho National Environmental and Engineering Laboratory
INJ	injection segment

IPE	individual plant examination
Kv	kilo-volts
LDST	Let Down Storage Tank
LER	Licensee Event Report
LOCA	loss-of-coolant accident
MCC	motor control center
MOOS	maintenance-out-of-service
MOV	motor-operated valve
MUT	make-up tank
NPRDS	Nuclear Plant Reliability Data System
NRC	U.S. Nuclear Regulatory Commission
NSSS	nuclear steam supply system
ORNL	Oak Ridge National Laboratory
PRA	probabilistic risk assessment
PWR	pressurized water reactor
PZR	pressurizer
RCS	Reactor Coolant System
RES	Office of Nuclear Regulatory Research
RHR	residual heat removal
RWST	Refueling Water Storage Tank
SAS	SAS Institute, Inc.'s commercial software package
SG	steam generator
SGTR	steam generator tube rupture
SI	safety injection
SCSS	Sequence Coding and Search System (database maintained at ORNL)
SUCT	suction segment
VCT	Volume Control Tank

TERMINOLOGY

Alpha factor— the fraction of the total frequency of failure events that occur in the system and involve the failure of k components (α_k) due to common cause.

Common cause failure—A dependent failure in which two or more components' fault states exist simultaneously, or within a short time interval, and are a direct result of a shared cause.

Common cause failure model—the basis for quantifying the frequency of common cause failures. Examples include beta factor, alpha factor, and basic parameter models. The binomial failure rate model is another model for quantifying common cause failures.

Common cause component group—a group of (usually similar) components that are considered to have a high potential for failure due the same cause or causes.

Common injection segment—The portion of the HPI system that applies to plants where the motor-driven pumps discharge to a shared header with flow to the cold water legs being regulated in the common header. This segment includes the piping and valves from (not including) the pump discharge isolation up to but not including the check valve just prior to entering the cold water leg. Included with the segment are the associated valves and valve operators, the injection/isolation valve and the control logic, and the test recirculation line if applicable.

Demand—An event requiring either the system or segment of the system to perform its safety function as a result of an actual valid initiation signal. Spurious signals or those inadvertent initiation signals that occurred during the performance of a surveillance test were classified as demands. An unplanned demand is either a manual or automatic start initiation of the system or segment that was not part of a pre-planned evolution. Unplanned demands typically were the result of safety injection demands.

Dependent failure—Two events are statistically dependent if the $\text{Prob}(A \cap B) = \text{Prob}(A)\ \text{Prob}(B|A) = \text{Prob}(B)\ \text{Prob}(A|B) \neq \text{Prob}(A)\ \text{Prob}(B)$.

Motor driven pump segment—The portion of the HPI system that includes the electric motor and associated breaker at the power board (excluding the power board itself). Also included with this segment is the pump and associated piping from and including the suction isolation valve up to and including the discharge isolation valve, and associated valve operators. The minimum flow and test recirculation line is included if the associated tap off is prior to the discharge isolation valve.

Error of commission (EOC)—A failure of the HPI system as a result of being purposely or inappropriately rendered inoperable by operator action when the system was needed to inject to the RCS.

Event frequency—The number of events of interest (failures, demands, etc.) divided by operating time.

Failure—An inoperability in which the capability of the HPI system or train to supply water to the RCS was lost when a demand for HPI existed. For estimating HPI unreliability, a subset of the failures was used (that is, only those that occurred on unplanned SI actuations).

Failure to run (FTR)—Any failure to complete the mission after a successful start of the pump train segment. This includes obvious cases of failure to continue running, and also cases when the train started and supplied water to the RCS, tripped off for a valid reason, and then could not be restarted.

Failure to operate (FTO)—Failure to operate occurs if the HPI train segment, other than pump train segment, prevents the HPI system from delivering water to the affected cold water leg. FTO-LOOP-INJ pertains to the cold leg injection path check valve segment immediately upstream of the cold leg. FTO-INJ-HDR generally refers to the piping/valve segment that contains the MOVs that receive a SI signal.

Failure to start (FTS)—Failure of the HPI pump train segment to start on a valid demand signal.

Fussell-Vesely Importance—An indication of the fraction of the minimal cut set upper bound that involves the cut sets containing the basic event of concern.

Independent failure—Two or more events are statistically independent if Prob($A \cap B$) = Prob(A) Prob(B).

Inoperability—An event affecting the HPI system such that it did not meet the operability requirements of plant technical specifications and therefore was required to be reported in an LER.

Maintenance out of service (MOOS)—A failure occurring during an unplanned demand that is attributed to a maintenance activity.

Maintenance unavailability—Probability that a system is out of service for maintenance at any instant in time.

Mission time—The elapsed clock time from the first demand for the system until plant conditions are such that the system is no longer required. PRAs typically assume that HPI to be available throughout the entire mission time.

Operating conditions—Plant conditions stated in technical specifications that require HPI operability, typically with the reactor vessel pressurized.

Operating data—A term used to represent the industry operating experience as reported in LERs. It is also referred to as operating experience or industry experience.

PRA/IPE—A term used to represent the data sources (PRAs, IPEs, and NUREGs) that describe plant-specific system modeling and risk assessment, rather than a simple focus on operating data.

P-value—The probability that the data would be as extreme as they are assuming that the model or hypothesis is correct. It is the significance level at which the assumed model or hypothesis is statistically rejected. In this study, a model was rejected (the trend was determined to be statistically significant) if the p-value is less than 0.05.

Recovery—An act that enables the HPI system to resume operation during the event without maintenance intervention. Generally, recovery of the HPI system was only considered in the unplanned demand events. Each failure reported during an unplanned demand was evaluated to determine whether recovery of the system by operator actions had occurred. Typically, a failure was recovered if the operator was able to reposition a switch, open a valve, or reset the governor to restore the HPI train segment failure. Events that required replacing components were not considered as recoveries. Also, for redundant trains, it may not be necessary to recover the failed train/piping segment immediately if the other redundant part succeeded. The LERs were further analyzed to determine those failures that may have been recovered if attempted.

Cold leg injection segment—The portion of the system that includes the check valve(s) and associated piping upstream of the common injection header segments. The last set of check valves in the injection path piping was included in this segment.

Suction segment—The portion of the HPI system that includes all piping, valves (including valve operators) and storage tanks associated with the suction source (typically the RWST) to the common pump suction isolation valves, including those isolation valves that supply water to the individual pump trains.

Total failure rate—The failure frequency of both independent and dependent failures.

Unreliability—Probability that the HPI system will not fulfill its required mission. This includes the unavailability contribution of the system being out of service for maintenance, as well as failures to start or run.

Reliability Study: High-Pressure Safety Injection System, 1987–1997

1. INTRODUCTION

The U.S. Nuclear Regulatory Commission (NRC), Office of Nuclear Regulatory Research (RES) 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 RES Division of Risk Analysis and Applications (DRAA) has undertaken to monitor and report upon the functional reliability of risk-important systems in commercial nuclear power plants. The approach is to compare the estimates and associated assumptions as found 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 High-Pressure Safety Injection systems in the U.S. commercial pressurized water reactors (PWRs) was performed. Because of the different terminology used throughout the industry for simplicity the High-Pressure Safety Injection systems will be referred to in this report as the High-Pressure Injection (HPI) system.

The evaluation measures HPI system unreliability using operating experience. To perform this evaluation and make risk-based comparisons to the relevant information provided in the PRAs, unreliability estimates are calculated using the data collected from the operating experience and data extracted from probabilistic risk assessments and individual plant examinations (PRA/IPEs). The operating experience based estimates of HPI system unreliability are derived from data from unplanned demands. These unplanned demands include actual SI actuations as well as spurious and inadvertent SI actuations. The data from this source are considered the closest representation of the plant conditions found during accident conditions. Data from component malfunctions that did not result in a loss of safety function of at least one train of the system were not utilized. Generally, data based on surveillance tests were not used in the estimation of HPI unreliability because failures of an individual train of HPI during a surveillance test are not reportable in accordance with 10 CFR 50.73, the Licensee Event Report (LER) reporting rule; and therefore an accurate count of these failures could not be obtained. However, for the suction segment (e.g: the RWST), failure data were extracted from quarterly surveillance test results contained in LERs since this represents a single failure of the HPI system. The objectives of the study were to:

- Estimate unreliability based on operational data, and compare the results with the assumptions, models, and data used in PRA/IPEs

- Provide an engineering analysis of the factors affecting system unreliability and determine if trends and patterns are present in the HPI system operational data.

This report is arranged as follows. Section 1 provides the introduction. Section 2 describes the scope of the study, describes the HPI system and system boundaries, provides the description of the six HPI design categories developed for this report, and briefly describes the data collection and analysis methods. Section 3 provides a discussion of the rationale of classifying failures as recoverable, a breakdown of the failure and demand counts used in estimating HPI unreliability, modeling of common cause failures, and the fault tree models associated with the six HPI design classes. Also contained in Section 3 are estimates of unreliability of the HPI system and pump train and injection header segments, design class differences, and comparisons to PRA/IPEs. Section 4 provides results on the trends of failures and unplanned demands by calendar year and low-power license date (i.e., newer plants versus older plants). Also included in Section 4 are engineering insights into the factors affecting the system, pump segment, and injection header segment reliability as well as an evaluation of the failures that contributed to the design class reliabilities. 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 LER data. The failure data used in the unreliability estimations are provided in Appendix C. Appendix D provides additional system unreliability information.

2. SCOPE OF STUDY

This study documents an analysis of the High-Pressure Injection (HPI) system operational experience for the PWRs listed in Table 1. For the purposes of this study, only the pumps and associated components that have an automatic start signal were considered as part of the system. Spare standby pumps that require operator actions (and in some cases several hours to install) were not modeled since they are incapable of mitigating situations that require immediate injection. The system boundaries, data collection, failure categorization, and limitations of the study are briefly described in this section.

Table 1 shows, for each plant, the number and type of trains (high-head and intermediate-head), the number of cold water legs, the reference report (e.g: IPE, PRA, etc.) used to obtain the estimates of plant-specific system unreliability, and other risk-related information.

2.1 System Operation and Description

2.1.1 System Purpose

The HPI system is part of the Emergency Core Cooling System (ECCS) that performs emergency coolant injection and recirculation functions to maintain reactor core coolant inventory and adequate decay heat removal following a loss-of-coolant accident (LOCA). The coolant injection function is performed during a relatively short-term period after LOCA initiation, followed by realignment to a recirculation mode of operation to maintain long-term, post-LOCA core cooling. In addition to the above, reactors which are equipped with pressurizer (PZR) power operated relief valves (PORVs) could use the PORVs and HPI to remove decay heat from the reactor in the event of the loss of the Main Feedwater (MFW) and Auxiliary Feedwater (AFW) systems.

The HPI system actuates automatically on low PZR pressure, high containment pressure, or when steam line pressure or flow anomalies are detected. Therefore, in addition to a LOCA, other events will lead to HPI actuation. Some examples of such events are Steam Generator Tube Ruptures (SGTRs), RCS overcooling events resulting from steam line breaks (e.g: Stuck open main steam safety valves), or RCS depressurization events (e.g: stuck open PZR spray valves).

2.1.2 System Description

The HPI systems analyzed have been grouped into six different design classes as shown in Table 1. The criteria used to determine this grouping are the number of steam generators, and the number of intermediate- and high-head safety injection trains available for automatic actuation. The number of steam generators rather than the number of cold legs was used as the criterion since that reduced the number of possible groupings of HPI design. Other groupings are possible, but this grouping utilizes two dominant design characteristics, which have the potential to dominate system reliabilities. Figure 1 is a block diagram of each of the design classes. These block diagrams show how the major system segments (e.g: RWST, pump trains, injection headers and cold legs) are connected to accomplish the HPI function. Even though a single block diagram represents all plants in a given design class, the design and operational differences within a design class (e.g: crossties, normally operating versus standby HPI pumps) were accommodated in modeling individual fault trees. Each system typically consists of at least two independent divisions. The divisions consist of a number of different combinations of motor-driven pump trains. Because of the diversity in system design, operation, and response to plant transients, a detailed discussion of the each plant-specific system is not practical. A general description is provided for the two major designs utilizing high head or intermediate head functional schemes. Differences between the other types of system design classes are also discussed.

Table 1. Listing of the HPI design classes, Units associated with each design class, the number and type of HPI trains, the number of cold-legs, and the success criterion for a small LOCA (as stated in the IPEs).

HPI Class	Plant	Report Reference	Centrifugal Charging Pumps (CCP)	Intermediate Head Safety Injection Pumps (IHSI)	Total High-Pressure Motor Trains	IHSI and CCP for ES Auto or Immediate Manual Start	Cold Leg Injection Paths	Steam Generators	Small LOCA success for HPI (injection phase)
1	Arkansas Nuclear One 1	1	3 (1 pump running; 1 swing pump never operates unless one of the two is in maintenance)	—	3	2	4	2	1/3 pumps; 2/4 injection paths; the swing pump has to be manually aligned to EDG and SW
1	Arkansas Nuclear One 2	2	—	3 (1 swing pump never operates unless one of the two is in maintenance)	3	2	4	2	1/3 pumps; 2/4 injection paths
1	Calvert Cliffs 1 & 2	7	—	3 (backup pump requires operator)	3	2	4	2	1/2 pumps to 2/4injection paths;
1	Davis-Besse	8	—	2	2	2	4	2	1/2 HPI pumps and flow to associated R/X nozzle
1	Kewaunee	11	—	2	2	2	2	2	1/2 HPIs to 1/2 cold legs, also allow for manual start of comp that didn't auto start
1	Millstone 2	12	—	3 (one pump is a swing pump that requires operator)	3	2	4	2	1/3 HPIs to 3 of 3 unfaulted loops OR 2/3 HPI supplying 2/3 unfaulted loops
1	Palisades	14	—	2	2	2	4	2	1/2 HPIs to 1/3 intact headers; assume SBLOCA fails fourth header
1	Palo Verde 1, 2, & 3	5	—	2	2	2	4	2	1/2 HPIs to 3/6 injection headers that feed the 3 RCS SI cold legs; SBLOCA assumed to fault one cold leg path
1	Point Beach 1 & 2	9	—	2	2	2	2	2	1/2 HPIs to the unfaulted loop initially takes suction from BAST then auto switch to RWST
1	Prairie Island 1 & 2	6	—	2	2	2	2	2	1/2 HPIs to 1/2 cold legs

Table 1. (continued).

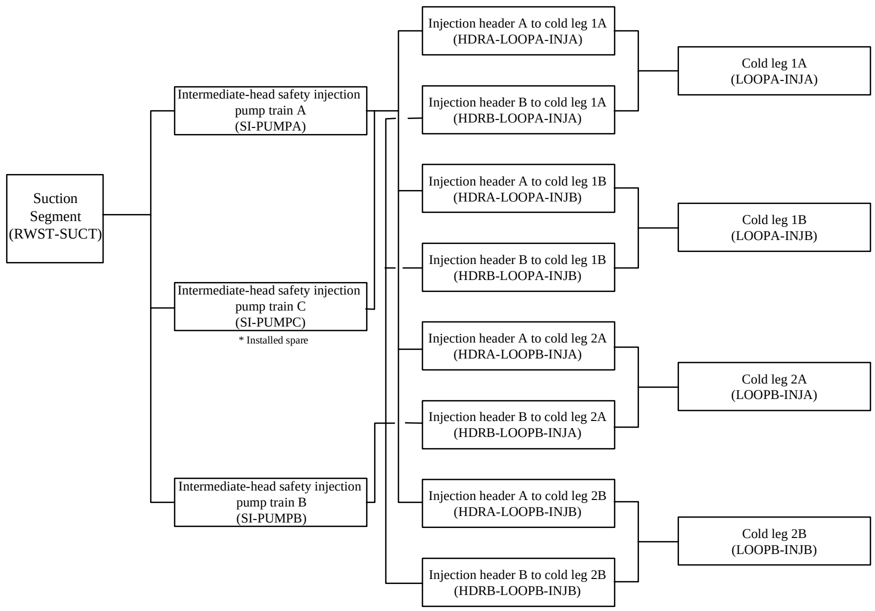
HPI Class	Plant	Report Reference	Centrifugal Charging Pumps (CCP)	Intermediate Head Safety Injection Pumps (IHSI)	Total High-Pressure Motor Trains	IHSI and CCP for ES Auto or Immediate Manual Start	Cold Leg Injection Paths	Steam Generators	Small LOCA success for HPI (injection phase)
1	San Onofre 2 & 3	15	—	3 (one requires operator to manual realign)	3	2	4	2	1/3 HPIs to 2/4 cold legs
1	St. Lucie 1 & 2	16	—	2	2	2	4	2	1/2 HPIs to 1/4 cold legs
1	Waterford 3	19	—	3 (one needs operator; installed spare)	3	2	4	2	1/2 HPIs to 2 intact cold leg injection paths
2	Crystal River 3	3	3 (1 pump running)	—	3	3	4	2	1/3 MUPs to 1/4 injection paths
2	Fort Calhoun	4	—	3	3	3	4	2	1/3 HPI to 2/4 legs
2	Ginna	10	—	3	3	3	2	2	1/3 HPI to 1/2 legs
2	Oconee 1, 2, & 3	13	3 (1 pump running)	—	3	3	4	2	1/3 HPIs to 1/4 RCS injection nozzles
2	Three Mile Island 1	17,18	3 (1 pump running)	—	3	3	4	2	1/3 HPIs through 1/4 injection paths
3	Beaver Valley 1	20	3 (1 pump spare)	—	3	2	3	3	1/3 Charging/HHSI pumps to 3/3 cold legs; model as 1/2CCPs to 3/3 cold legs since spare pump is unpowered
3	Beaver Valley 2	21	3 (1 pump spare)	—	3	2	3	3	1/3 Charging/HHSI pumps to 3/3 cold legs; model as 1/2CCPs to 3/3 cold legs since spare pump is unpowered
3	Farley 1 & 2	22	3 (serves as HPI; one requires operator)	—	3	2	3	3	1/2 HPI pumps to 2/3 cold legs for 4 hours;1 normally operating, 1 in standby, 1 as backup to be aligned if one of the others is not available
3	H.B. Robinson	26	—	3 (1 pump breaker is racked out)	2	2	3	3	1/2 HPIs; 1 HPI pump is at time of IPE undergoing major overhaul hence disabled.
3	Maine Yankee	24	3 (1 pump run, 1 pump standby, 1 pump spare)	—	3	2	3	3	1/2 HPSI trains to 1/2 intact cold water loops from RWST; no credit for spare

Table 1. (continued).

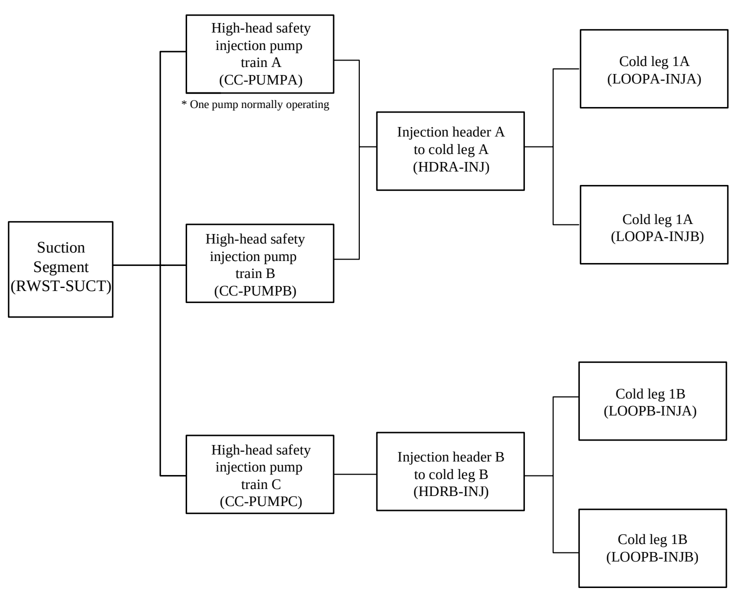
HPI Class	Plant	Report Reference	Centrifugal Charging Pumps (CCP)	Intermediate Head Safety Injection Pumps (IHSI)	Total High-Pressure Motor Trains	IHSI and CCP for ES Auto or Immediate Manual Start	Cold Leg Injection Paths	Steam Generators	Small LOCA success for HPI (injection phase)
3	North Anna 1 & 2	25	3 (1 pump running; 1 needs operator)	—	3	2	3	3	1/3 HHIs; model as 1/2 HHIs since third pump needs manual alignment
3	Shearon Harris 1	23	3 (1 pump running; 1 pump spare)	—	3	2	3	3	1/2 HPIs *(one normally operating; have a spare pump that can be available in 8 hours)
3	Summer 1	27	3 (1 pump running; 1 pump breaker is racked out)	—	3	2	3	3	1/2 HPSIs to 2/3 cold legs
3	Surry 1 & 2	28	3 (1 pump is in "pull-to –lock")	—	3	2	3	3	1/3 HHSIs to 1/3 cold legs; HHSI limited to simultaneous operation of 2 of 3 HHSI pumps
4	Turkey Point 3 & 4	29	—	4 (2 per unit)	4 (2 per unit)	2	3	3	2/4 HHSI trains to 1/3 cold legs; taking credit for other units pumps
5	Indian Point 2	39	—	3	3	3	4	4	1/3 HPIs to 1/4 cold legs
5	Indian Point 3	40	—	3	3	3	8	4	1/3 HPIs to 1/4 cold legs
5	South Texas 1 & 2	48	—	3	3	3	3	4	1/3 HPSIs to 1/3 cold legs
6	Braidwood 1&2	30	2	2	4	4	8; 4per sys	4	1/4 CC or SI pumps to 2/4 injection paths
6	Byron 1 & 2	31	2	2	4	4	8; 4per sys	4	1/4 CC or SI pumps to 2/4 injection paths
6	Callaway	34	2	2	4	4	8; 4per sys	4	1/4 CC or SI pumps to 2/4 injection paths
6	Catawba 1 & 2	35	2 (1 pump running)	2	4	4	8; 4per sys	4	1/4 NI or NV pumps to 2/4 injection paths
6	Comanche Peak 1 & 2	36	2	2	4	4	8; 4per sys	4	1/4 pumps to 2/4 injection paths
6	Cook 1 & 2	37	2	2	4	4	8; 4per sys	4	1/2 CCPs AND 1/2 SI pumps to 1/3 intact loops
6	Diablo Canyon 1 & 2	38	2	2	4	4	8; 4per sys	4	1/4 CCPs or SI pumps to 1/4 RCS cold legs

Table 1. (continued).

HPI Class	Plant	Report Reference	Centrifugal Charging Pumps (CCP)	Intermediate Head Safety Injection Pumps (IHSI)	Total High-Pressure Motor Trains	IHSI and CCP for ES Auto or Immediate Manual Start	Cold Leg Injection Paths	Steam Generators	Small LOCA success for HPI (injection phase)
6	Haddem Neck	33	2	2	4	4	5	4	(1/2 HPIs to 3 of 3 unfaulted legs OR 2/2 HPIs to 2 of 3 unfaulted legs) AND 1/2 CCPs to # 2 cold leg
6	McGuire 1 & 2	41	2 (1 pump running)	2	4	4	8; 4per sys	4	1/4 CC or SI pumps to 2/4 injection paths
6	Millstone 3	42	3 (1 pump running, 1 needs operator)	2	5	4	8; 4per sys	4	1/4 HPIs to 3/3 unfaulted RCS cold legs
6	Salem 1 & 2	43	2	2	4	4	8; 4per sys	4	1/4 centrifugal charging or SJS pumps
6	Seabrook	32	2	2	4	4	8; 4per sys	4	1/4 HPI trains (SI or CVCS) to 2/4 cold legs
6	Sequoyah 1 & 2	44	2	2	4	4	8; 4per sys	4	1/4 HPI trains (SI or CVCS) to 2/4 cold legs
6	Vogtle 1 & 2	45	2 (1 pump running)	2	4	4	8; 4per sys	4	1/2 CCPs through 3/4 cold legs for 3 hrs. OR 1/2 SIs through 3/4 cold legs for 6 hours
6	Wolf Creek	46	2	2	4	4	8; 4per sys	4	1/4 HPS is to 3/4 cold legs
6	Zion 1 & 2	47	2 (1 pump running)	2	4	4	8; 4per sys	4	1 CCP(high-pressure) or 1 SIP (medium pressure)

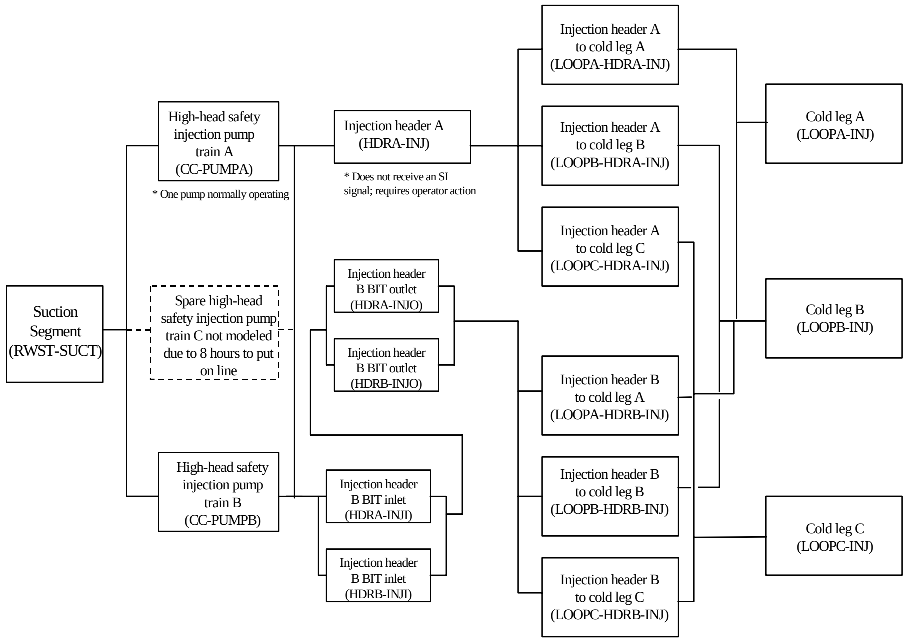


Waterford 3 (Design Class 1)

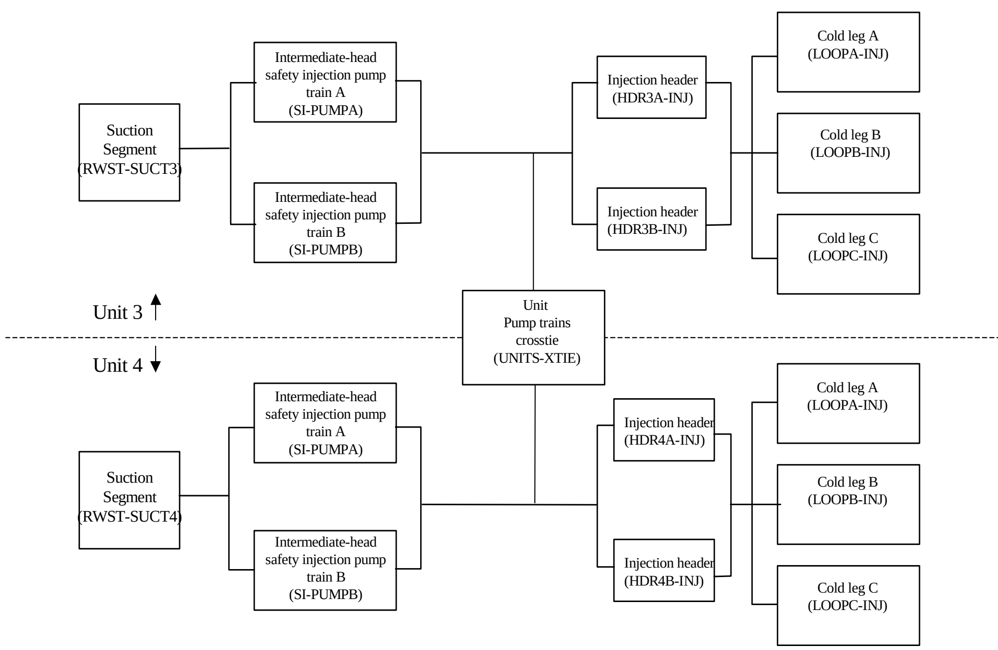


Oconee 1,2, & 3 (Design Class 2)

Figure 1. Simplified block diagrams of HPI systems for each of the 6 design classes.



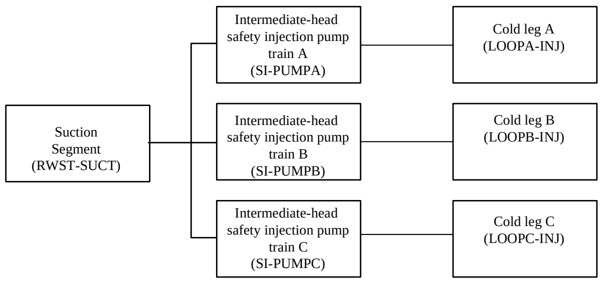
Harris (Design Class 3)



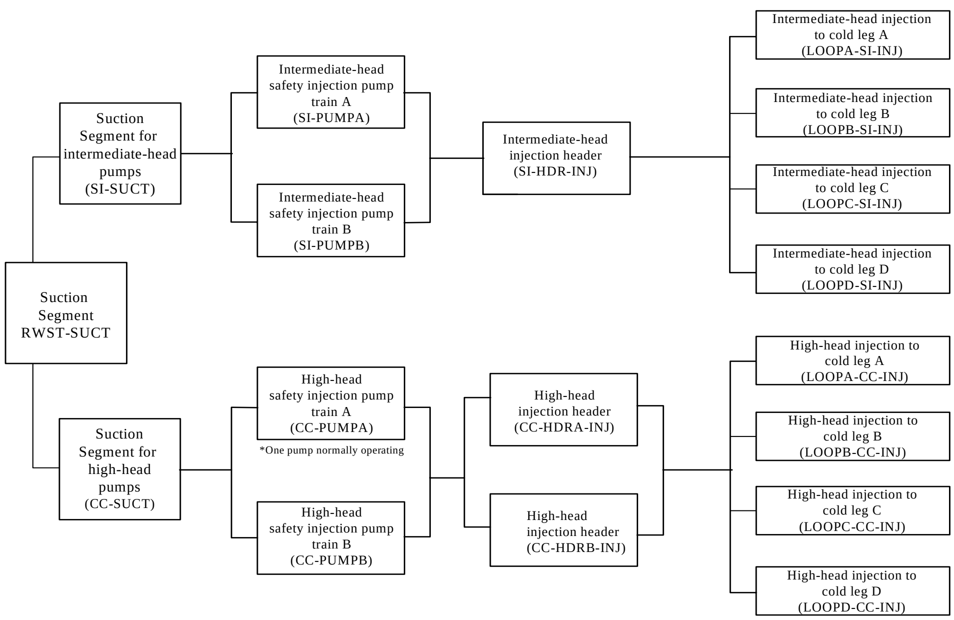
* All 4 pumps start on ES signal; only affected unit valves operate

Turkey Point 3 & 4 (Design Class 4)

Figure 1. (continued).



South Texas (Design Class 5)



Braidwood 1 and 2 (Design Class 6)

Figure 1. (continued).

The HPI system is typically not in service during normal plant operations. It is considered part of the Emergency Core Cooling System (ECCS) and is used to restore primary coolant volume during LOCAs, depressurization events, and overcooling events. However, the HPI systems have wide variation from vendor to vendor and from plant to plant. In some plants, B&W in particular and in some Westinghouse designs, the normal make-up pumps are also the HPI pumps, and therefore a portion of the HPI system is in service during normal modes of plant operation. The Combustion Engineering and other Westinghouse designs commonly use a charging system for normal make-up that is separate from the safety injection pumps, which are used only during emergency or abnormal situations. However, even in these designs the make-up and safety injection systems are inter-related because they share common valves, water sources, piping runs, and other equipment. Consequently, the safety injection systems can be either intermediate-head capacity (approximately 1400 psi), or high-head capacity (approximately 2200 psi) depending on whether they are used for normal charging (high-head) or not (intermediate-head). These differences in system pressure determine how it is used during emergencies.

The HPI system is typically started automatically by the engineered safety features actuation system (ESFAS) or equivalent, depending on plant design and terminology. Generally, the ESFAS automatic start signal setpoints include a low reactor coolant system pressure or a high reactor building (i.e., containment) pressure signal. There are additional start signals, but these two are typical.

As mentioned before, in some PWRs (includes Arkansas Nuclear One–Unit 1 and all Design Class 2 and 3 plants except Fort Calhoun, Ginna, and H.B. Robinson), the normally running charging pumps are used to perform the HPI function. In these plants, during normal operations, the charging-pump/make-up pump takes suction from the volume control tank (VCT)/make-up tank (MUT). The level in this tank is maintained from letdown received from the purification loop of the reactor coolant system (RCS), reactor coolant pump (RCP) seal return, charging/make-up pump recirculation, and other minor sources. Borated water is added to the VCT/MUT occasionally depending on losses in the system, such as RCS leakage or operational requirements to borate or deborate. During emergency operation, the suction of the charging/make-up pumps is changed. Several valves reposition automatically upon receipt of a safety injection signal. This allows a large reserve tank to supply borated water to the suction of the charging/safety injection pumps. This large tank is commonly called the refueling water storage tank (RWST) or borated water storage tank (BWST). The water in this tank has a high boron concentration, generally 2400 ppm boron. The tank volume varies from about 245,000 to as high as 450,000 gallons but is often in the 338,000 to 425,000 gallon range. Once the valves have repositioned, the head from the RWST/BWST seats the VCT/MUT outlet check valve, and thereby the highly borated water is supplied to the SI pumps.

During emergency situations, when the water in the RWST/BWST is depleted, water is available to the HPI pumps from the reactor building or containment building sump. This water may be directly available to the SI pumps via piping and valves or it may require a low-pressure stage pump to provide sufficient net positive suction head (NPSH) to the SI and charging/make-up pumps. This source of water becomes extremely important during emergencies that require a prolonged time for injection before being terminated and possibly exhausting the RWST/BWST water capacity. In this case, the HPI system is used in the "recirculation mode."

The above discussion mainly applies to designs where the charging/make-up pumps used in normal operation are also the HPI pumps during emergencies. These pumps require the low-pressure pumps to provide NPSH from the reactor building or containment building sump, for example Oconee 1, 2, and 3 utilize this design. The following applies to those designs that incorporate separate SI pumps and charging/make-up pumps. For these designs, the charging/make-up pumps operate the same as mentioned above. That is, during normal operation the charging pumps take suction from the VCT/MUT. However, upon receipt of a safety injection signal, the pumps take suction from the RWST and the valves between the VCT/MUT and the charging pump suction close (typically, there are two valves). However, the dedicated SI pumps can only take water from the RWST/BWST and not the VCT/MUT like the charging/make-up pumps. These SI pumps are intermediate head. The intermediate-head SI pumps will require the charging/make-up pumps to be in operation until the RCS press decreases to the pressure where the intermediate-head pumps can inject water. At this point the charging/make-up pumps can be turned off or left on to help inject a greater volume of water. Braidwood 1 and 2 is an example of this design. The final plant design contains only intermediate-head SI pumps that are used for HPI. These pumps take suction from the RWST/BWST for injection and are aligned to take suction directly from the reactor building or containment build sump during "recirculation mode." Waterford is an example of this design.

In the plants equipped with charging/make-up pumps and dedicated SI pumps (Design Class 6 plants), typically, during normal operation, the charging/make-up pumps supply make-up or cooling water to plant equipment. One is the RCP seal supply. This normally requires 8 to 10 gpm per reactor coolant pump. Another function is pressurizer level control. This system senses pressurizer level and opens or closes the pressurizer level control valve allowing more or less make-up to maintain the selected pressurizer level setpoint. Most of the flow from the charging/make-up pumps is returned to the VCT/MUT via recirculation piping and valves during normal system operation. Once an ECCS signal is received or the operator manually repositions valves to their emergency position, the discharge of the charging/make-up pumps is redirected. There are generally three or four injection nozzles to the RCS for HPI. These nozzles, located in the cold legs of the RCS have instrumented piping connected to them from the charging/make-up pumps and SI pumps depending on the design. Some of the devices and instrumentation on the discharge piping include, but is not limited to injection/isolation valves, flow-balancing orifices, flow crossover piping, and nozzle and total flow indicators. The flow from the SI and the charging/make-up pumps to the RCP seals is reduced. The charging/make-up pump recirculation back to the VCT/MUT is also automatically terminated in order to maximize SI flow into the RCS.

2.1.3 System Boundaries

For the purposes of this analysis, the HPI system is partitioned into several different segments. These segments are (1) suction, (2) pump train, (3) pump injection header, (4) shared injection header, (5) cold leg injection, and (6) Instrumentation and Control subsystem. These segments are described in more detail below:

1. The suction segment includes all piping and valves (including valve operators) from the RWST/BWST to the pump suction header. Also included in this segment are the components and equipment used for VCT isolation and the transfer of pump suction to the RWST.

2. The pump train segment includes the motor and associated breaker, but excludes the electrical power bus itself. Also included with this segment are the pump and associated piping from (and including) the pump-suction header up to and including the discharge header valves, and associated valve operators. The minimum flow and test recirculation line is included if the associated tap off connects prior to the discharge isolation valve.

3. The pump injection header segment includes the piping and valves from the pump discharge isolation valve up to the cold-leg or cold-leg injection segment depending on whether multiple injection segments feed a common cold-leg injection header. This segment begins downstream from the pump discharge isolation valve (or discharge header) and terminates at the point connecting to alternate injection paths (or cold-leg for plants that do not have a shared injection header since these plants have dedicated injection paths from the pumps to

the cold legs). Included with the segment are the associated valves and valve operators, the injection valve and control logic, and the test recirculation line where applicable.

4. The common injection control segment applies to plants where the pump discharges to a shared header with flow to the cold-leg being regulated in this common line. This segment includes the piping and valves from (but not including) the pump discharge isolation up to the cold-leg for plants with only one injection header per cold-leg. For plants with more than one injection header per cold-leg or where the injection path connects with another injection systems, the injection control segment includes piping up to the connection point for the alternate injection path. Included with this segment are the associated valves and valve operators, the injection/isolation valve and the control logic, and the test recirculation line where applicable.

5. The cold-leg (loop) injection segment includes the check valve(s) and associated piping downstream of the common injection header segments. This segment generally includes the last check valves in the injection system piping immediately upstream of the RCS cold leg.

6. The Instrumentation and Control subsystem includes the circuits for initiation of the HPI system. It includes sensors, transmitters, instrument channels, and analog or solid state components used for HPI train actuation.

Additional components that were considered to be part of the HPI system are the circuit breakers at the motor control centers (MCCs) (but not the MCCs themselves) that are specifically dedicated to the HPI system. Heating, ventilating, and air conditioning systems and room cooling dedicated with the HPI system were also included. Losses of a specific HPI room cooler are included if the losses cause failure of the HPI system or train to perform its intended function. However, failures within the service water system are not included in the quantification.

Failures associated with the HPI system caused by support system failures are included in this study in order to derive engineering insights and to perform sensitivity analysis of these failures on the HPI system unreliability. Support system failures were defined as failures of systems (or components) that affect the operation of the HPI system. These support systems included, but were not limited to, 4160 and 480 Vac vital power, 125 Vdc power, service water, engineered safety feature actuation system (ESFAS), and solid state protection system (SSPS). However, because the support system failure contribution to the overall HPI system failure probabilities would be modeled separately in the PRAs, support system failures were not included in the unreliability estimates used to compare with the plant specific PRA/IPE results in Section 3.

2.2 Collection of Plant Operating Data

The HPI system operational data used in this report are based on LERs cataloged in the Sequence Coding and Search System (SCSS) database. The SCSS database was searched for all records that explicitly identified an engineered safety feature (ESF) actuation or failure associated with the HPI system for the years 1987 through 1997.

It is assumed for this study that every plant was reporting HPI ESF actuations and failures consistently as required by the LER rule, 10 CFR 50.73, and the guidance provided in NUREG-1022, *Event Reporting Systems 10 CFR 50.72 and 50.73.* (HPI ESF actuations were found to be reported for all plants during the study time period.) HPI events that were reported in accordance with the requirements of 10 CFR 50.72 (Immediate Notification Reports) are not explicitly used in this study, because the LERs (i.e., 10 CFR 50.73 reports) provide a more complete description, thus making it easier to determine whether the HPI had operated successfully or not.

2.2.1 Characterization of Inoperability Data

The information encoded in the SCSS database, and included in this study, encompasses events that occurred during all plant operating conditions. In this report, the term *inoperability* is used to describe any HPI component malfunction either actual or potential, for which an LER was submitted in accordance with the requirements identified in 10 CFR 50.73. It is distinguished from the term *failure*, which is the subset of inoperabilities for which a segment of the system was not able to perform its safety function. Specifically, for an event to be classified as a failure the component/pipe-segment would have to be found (or judged) to have not successfully fulfilled the actual or postulated safety mission for which the system was designed. The inoperabilities that were not classified as failures are primarily potential failures or administrative deficiencies (e.g: late performance of surveillance tests, missing seismic restraints, etc.).

The HPI system is a safety system. Any occurrences in which the system was not able to perform its safety function, as defined by plant technical specifications, are required by 10 CFR 50.73 to be reported. However, because the HPI system consists of redundant trains, and only a single train is required (typically) to perform the safety function, train-level inoperabilities do not require an LER. Specifically, plants are not required to report single train inoperabilities unless the event resulted in an outage in excess of technical specification allowable outage times, or resulted in a unit shutdown required by technical specifications. Otherwise, occurrences where a train was not fully operable would not be reported. For example, no LER would be required if, during the performance of a surveillance test, a motor-driven pump failed to start, provided the redundant train(s) were operable and the cause of the failure to start was corrected and operability restored prior to expiration of the technical specification limiting condition for operation. This reportability requirement effectively means surveillance test data cannot be used for the unreliability calculations since most of these failures are likely not reported. However, for ESF actuations, all component failures that occurred as part of or in conjunction with the ESF actuation are assumed to be described in the narrative of the LER as required by 10 CFR 50.73(b)(2)(ii). Because all ESF actuations are reportable under 10 CFR 50.73(a)(2)(iv), the failures listed in an LER describing an ESF actuation are assumed to be complete. Additional information concerning the identification and classification of the LER data are provided in Section A-2.1 of Appendix A.

2.2.2 Failure Classification

The information encoded in the SCSS database was only used to identify and select LERs for the review and classification. Analysts experienced in PRA and in U.S. commercial NPP operations reviewed the full text of the selected LERs. Care was taken to properly classify each event and to maintain consistency of the classification process. The focus of this report is on risk and reliability. Therefore it was necessary to review the full text of each LER and classify or exclude events based on whether the HPI component/segment/train/system could fulfill its intended safety function if it was actually needed to mitigate an accident. Specifically, the information necessary for determining reliability, such as classification of HPI failures, failure mode, failure mechanism, and cause, was based on redundant and independent reviews of the selected LERs. Again, the SCSS data search was used only to identify those LERs relevant to this study; no data characterization, evaluation, or reliability analysis was performed using the information encoded in the SCSS database.

Failure classification of the inoperability events was based on the ability of the segment to function as designed for the assumed mission. The operational mission requirements vary based on the type of transient experienced by the plant. Typically the operational missions require system operation for only a few minutes. Inoperability events were classified for the operational mission based on the operational requirements of the actual unplanned event (i.e., how was the system actually needed).

The events identified in this study as segment failures represent actual malfunctions that prevented the successful operation of a particular pipe segment. Segment failures identified in this study are not necessarily failures of the HPI system to complete its mission. Specifically, a motor-driven pump segment might have failed to start; however, the redundant motor-driven pump segment would have responded as designed. Therefore, the *system* did not fail. For the purposes of this study, the following segment failure modes were considered during the review of the operational data:

- Maintenance out of service (MOOS) event is one in which, because of maintenance activities, the affected segment was prevented from starting automatically during an unplanned demand.

- Failure to start (FTS) occurred if the pump segment was nominally in service (i.e., not classified as MOOS) but failed to automatically or manually start, and generate sufficient pressure and flow. This failure mode only applies to the pump segments.

- Failure to run (FTR) event is one in which the pump segment was delivering sufficient pressure and flow (i.e. successful start), but the segment failed to maintain sufficient pressure and flow during the time it was needed (or would have been needed). This failure mode only applies to the pump segments.

- Failure to operate (FTO) occurred if a segment (other than a pump segment) could not perform its required design function when needed. For example, a segment with a motor-operated valve failed to open on demand, or a normally open valve fails to remain open.

- Common cause failure (CCF) is a failure of two or more segments resulting from the same root failure mechanism that prevented the components from performing their required safety function.

- Error of commission (EOC) occurs if the HPI system was rendered inoperable by operator action when the system was needed.

Recovering from a failure is also considered in the reliability calculations. To recover from a segment failure, the operators have to recognize that the segment is in a failed state, and then restore the function of the segment without actually repairing or replacing hardware. (This is because the time and resources available for recovery depends on the specifics of an accident scenario and can vary greatly.) An example of such a recovery would be an operator (a) noticing that the pump failed to start and (b) manually starting the pump. Each failure during an unplanned demand was evaluated to determine whether recovery by the operator occurred or was possible.

There were some failure events during which the operators elected not to recover a failure because a redundant segment of the HPI system was successfully operating. For example, if the pump tripped during start and the other pump was operating properly, the operators may have elected to not recover the failed pump. To minimize any potential bias in the estimates of the recovery probabilities, failures that the operators did not attempt to recover were further analyzed to determine if they could have been recovered. If the failure mechanism was such that recovery was possible, the failure was judged to be recoverable.

The analysis section of most LERs provided information useful for determining if the segment would have been able to perform as required even though it was not operable as defined by plant technical specifications. For example, a section of pump discharge piping was found to have less than the required number of seismic restraints, and therefore was declared inoperable in accordance with the plant technical specifications. However, since the operation of the system during a small LOCA coincident with a seismic event is not a mission considered in this study, and the pump would have worked during a small LOCA in spite of the missing seismic restraint, this event was not classified as a failure.

In addition, administrative problems associated with HPI were not classified as failures. As an example, an LER may have been submitted specifically for the late performance of a technical specification required surveillance test. This event would not be classified as a failure in this study. This classification is based on the judgement that, given a demand for the segment, the segment would be capable of performing its safety function. Moreover, in cases like this, LERs typically state that the segment was available to respond to a demand, and that the subsequent surveillance test was performed satisfactorily. If the LER stated that the segment failed the subsequent surveillance test, that event would be classified as a failure.

As a result of the review of the LER data, the number of events classified and used in this study to estimate HPI unreliability will differ from the number of events and classification that would result from a simple SCSS database search. Differences between the data used in this study and a tally of events from an SCSS search stem primarily from the completeness of the data (i.e., reportability requirements for both demands and failures) and the exclusion of events where the failure mechanism is either outside the HPI system boundary or inconsistent with the definition of failure used here. Because of these differences, the reader and/or analyst is cautioned from making comparisons of the data used in this study with a simple tally of events from SCSS without first making a detailed evaluation of the data provided from a reliability and risk perspective. Appendix C provides a listing and summary of the events used in estimating the unreliability of the HPI system.

2.2.3 Characterization of Demand Data

To estimate reliability, information on the frequency and nature of the HPI demands is also needed. For the purposes of this study, a demand is defined as an event requiring either the system or segment of the system to perform its safety function as a result of a safety injection (SI) signal. Spurious signals or those inadvertent SI signals that occurred during surveillance testing of systems other than HPI were also classified as demands if the HPI system was normally expected to be operational, since these demands are required to be reported. An unplanned demand is defined as either a manual or automatic SI initiation of the system or segment that was not part of a pre-planned evolution. Unplanned demands are typically the result of actual safety injection demands or inadvertent SI signals. Other plant conditions may have also resulted in an unplanned demand of HPI based on the plant-specific design of the HPI initiation circuit. These initiations of HPI were also included in the study if they resulted from an automatic SI signal.

The LERs identified from the SCSS database search were reviewed to determine the nature and number of HPI unplanned demands. Each LER was reviewed to determine what portion(s) of the system were demanded. For cases where the LER did not provide clear indication of what portion(s) of the system were demanded, the IPE or Final Safety Analysis Report (FSAR) for each plant was reviewed to determine the initiation setpoints and operating characteristics of the system for the specific plant. In addition to the setpoints and operating characteristics, the plant-specific system schematics were also reviewed. The purpose of this review was to determine which segment(s) of the system were demanded, given the initiation setpoints and operating characteristics of the system, when reviewing the full text of each LER.

The identification of the system initiation setpoints, operating characteristics and schematics for the system were necessary to capture the unplanned demand frequency because many LERs simply stated that all systems functioned as designed. Since the full text of the LER describes the plant conditions before and during the reported event, the information provided in the IPE and FSAR were used to determine whether an unplanned demand of HPI occurred. For example, an LER might state that a pressurizer low pressure condition existed during the event. Using the information provided in the IPE or FSAR for that particular plant, a determination was made whether the condition resulted in an automatic safety injection signal. Even though no explicit identification of the HPI pump start was found in the LER. Therefore, based on the narrative of each LER and plant-specific knowledge concerning HPI initiation and operation, it was possible to determine a relatively accurate number of HPI unplanned demands throughout the industry. For more details on the counting of unplanned demands, see Section A-2.2 in Appendix A.

Data from the surveillance tests that are performed approximately every operating cycle were also considered for use in estimating system reliability. Plant technical specifications require that the 18-month surveillance tests simulate automatic actuation of the system throughout its safety-related operating sequence and that each automatic valve actuate to the correct position. In addition to the 18-month surveillance tests, quarterly surveillance tests of the pumps that are required to be performed per ASME (1989) Section XI, in-service testing programs, could also be used to estimate reliability. However, because surveillance test failures of a single train would not be required to be reported, as discussed previously, the number of failures found in the LERs could be significantly less than the number that actually occurred. Consequently, this effectively removed any surveillance test data from being considered for the reliability estimate.

As a result of the review of the LER data, the number of events classified and used in this study to determine the number of HPI unplanned demands will differ from the number of ESF actuations identified in a simple SCSS database search. This difference is the result of the coding methodology employed in coding an event for SCSS and analysis of the LER in this study. Specifically, SCSS will only capture explicitly identified HPI ESF actuations, while in this study, the intent was to capture all actual HPI unplanned demands. Because of this difference, the reader and/or analyst is cautioned from making comparisons of the data used in this study with a simple tally of events from SCSS without first making a detailed evaluation of the data provided in the LERs and a review of the system operating characteristics and initiation parameters. The results of the LER review and evaluation are provided in Appendix B, Section B-1.

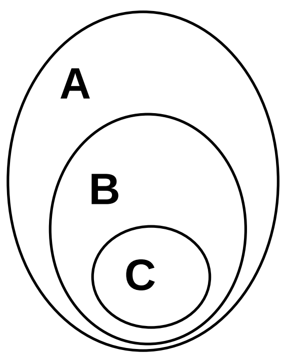
2.3 Operational Data Analysis

The risk-based and engineering analysis of the operational data are based on two different data sets. The Venn diagram in Figure 2 illustrates the relationship between these data sets. Data Set A represents all the inoperabilities found using SCSS. Data Set B represents the subset of inoperabilities that are classified as failures. Data Set C represents a subset of the failures for which the corresponding demands (both failures and successes) could be counted (i.e., countable failures with countable demands).

Data Set C, which consists of the countable failures, provides the basis for estimating the unreliability of the HPI system. Data Set C contains all relevant failures that occurred during an unplanned demand. The only criteria are the occurrence of an actual failure and the ability to count or estimate all corresponding demands (i.e., both failures and successes). Data Set C represents the minimum requirements for the data used in the risk-based analysis of the operational experience, and is the source data for Section 3 of the report.

To eliminate any bias in the analysis of the failure and demand data in Data Set C and to ensure a homogeneous population of data, three additional selection criteria on the data were imposed. These criteria were the following: (1) the data from the plants must be reported in accordance with the same reporting requirements, (2) the data from each plant must be statistically from the same population, and (3) the data must be consistent (i.e., from the same population) from an engineering perspective. Each of these three criteria must be met or the results of the analysis would be incorrectly influenced. As a result of these three criteria, the failure and demand data that comprise Data Set C were not analyzed strictly on the ability to count the number of failures and associated demands for a risk-based mission, but also to ensure that each of the above three criteria were met.

The purpose of the engineering analysis is to provide qualitative insights into HPI system performance and not calculate quantitative estimates of unreliability. Therefore, the engineering analysis uses the failures appearing in the operational data. That is, the engineering analysis focused on Data Set B, which includes Data Set C, with an engineering analysis of the factors affecting HPI system unreliability.



A Represents all the inoperabilities identified from the SCSS database search.

B Represents the inoperabilities that are classified as failures.

C Represents the subset of failures for which the demand counts could be determined or estimated, countable failures.

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

3. RISK-BASED ANALYSIS OF THE 1987–1997 EXPERIENCE

This section documents the results of the reliability analyses in two ways. First, estimates of HPI unreliability for the actual missions experienced were calculated using the HPI 1987–1997 experience. These unreliability estimates are based on the HPI missions that result from routine transients that include a SI actuation and a demand for high-pressure safety injection. These demands for HPI operation can range from a few minutes to a few hours. The estimates of HPI system unreliability (injection phase only) for this operational-based mission were analyzed to uncover patterns in system performance on a plant-specific and industry-wide basis.

Second, HPI system unreliability (injection phase only) was estimated using the fault trees developed for this study, but using the HPI component failure data reported in PRA/IPEs (see References 1 through 48). Adjustments were made to the mission time assumed in the PRA/IPEs (typically several hours to 24 hours) to allow a fair comparison between unreliabilities calculated using the PRA/IPE data and the 1987–1997 experience. For the purposes of this study, the risk reports are referred to collectively as PRA/IPEs. These reports document data and results of probabilistic risk analyses for 72 operating PWR plants. PWRs that were permanently shut down at the time of this study were not included. (These PWRs that were shutdown are Trojan, San Onofre Unit 1, Rancho Seco, and Yankee Rowe.) Further, PWRs that just began operation at the end of the study's time period were not included (Watts Bar operation date 5/96).

HPI unreliabilities were estimated using fault tree logic models that combine the probabilities of broadly defined failure modes such as failure to start and failure to run into an overall system result. The probabilities of the individual failure modes were calculated by reviewing the available data (see Appendix C), and categorizing each failure event and successful demand, by failure mode and system segment. Generally, the HPI fault tree logic models were not available in the PRA/IPEs, since the models were not required to be submitted to the NRC. However, the component failure probabilities used in calculating HPI unavailability were documented. HPI unreliabilities were calculated using the HPI component failure data contained in the PRA/IPEs and using the fault trees developed for this study. The component failure probabilities were extracted and linked to the corresponding system failure modes identified in the fault tree developed for the analysis of the 1987–1997 experience. The component failure probabilities extracted from the PRA/IPEs were only those identified as the major contributors to HPI unavailability. Therefore, the PRA/IPE estimates approximated for this study are likely to be different from those used in PRA/IPE quantification. However, since the major contributors are used, the differences are not expected to be large.

Besides the plant-specific estimates, six HPI system design classes were identified to distinguish the differences in redundancy, diversity, and operation among the various HPI system designs. Plant-specific estimates of HPI unreliability are grouped according to design class to provide additional insights into HPI system reliability.

The following is a summary of the major findings:

- Based on the 1987–1997 experience data, there were no failures of the entire HPI system identified in 224 unplanned system demands. Using a system level fault tree model that combines individual failure modes, the unreliability (injection phase only) of the HPI system calculated by arithmetic averaging the results of 72 plant-specific models is 4.5E-04.

- Individual plant results vary by about a factor of fifty, from 6.0E-05 to 3.5E-03. The variability reflects the diversity in HPI system designs. However, there is variability in results among plants with similar HPI designs (factors of ten between highest and lowest

HPI unreliabilities). This is attributed to the differences in the levels of redundancy in the injection headers. Section 3.2.4 discusses the within design class differences.

- The dominant contributors to HPI unreliability (injection phase only) vary depending on the HPI design class.

  - For HPI designs consisting of three or fewer pump trains, common cause failure (CCF) accounts for 72% to 95% of HPI unreliability. The major CCF contributors to these configurations are CCF of the injection headers failing to operate and CCF of HPI pumps failing to start and failing to run (not in the order of importance). Although there were no CCF events identified in the unplanned SI actuations, CCF events were identified in the remaining set of 1987–1997 events.

  - For HPI designs composed of two high-head and two intermediate-head pump trains, random failures of the common RWST and associated suction piping are the leading contributors to unreliability, approximately 93%.

- The industry-wide arithmetic average of HPI system unreliability (injection phase only) calculated using data extracted from PRA/IPEs is 5.8E-04. The corresponding estimate based on the 1987–1997 experience is 4.5E-04. Both of these estimates use a half-hour mission and do not account for non-safety trains and equipment available at some plants (for example, the use of non-safety grade injection pumps as backups to HPI or an installed spare HPI pump). The PRA/IPE and 1987–1997 operating experience estimates were generally comparable except for HPI Design Class 6. Section 3.3.2 provides the results and insights for comparison with PRA/IPE results.

3.1 HPI Unreliability Data and System Modeling

Estimates of HPI unreliability (injection phase only) were calculated using the unplanned demands (i.e., SI actuations) reported in the LERs and surveillance test data associated with the RWST. Testing data associated with redundant equipment were not used as part of the 1987–1997 experience because of concerns about the reportability of test failures involving redundant train systems. A failure involving total system failure is reportable, but failure of a single train is not. Due to the reportability issue, the counting of demands and failures from tests cannot be done with any degree of confidence for the redundant trains. However, test data were used when calculating the failure probability associated with the RWST suction source since failure of the RWST represents total system failure. Therefore, RWST failures are reportable. The failure data used to develop failure probabilities for the observed failure modes are described in more detail in Section 2.2. The contributions to the unreliability of the HPI system from support systems outside the HPI boundary defined in Section 2.1.3 are excluded from the failure counts.

The failures identified for the HPI system fall into the following failure categories: suction path faults, pump/valve train maintenance-out-of-service, pump/valve train segment failure to start and failure to run, injection header failing to operate, and the cold leg injection path failing to operate. The maintenance-out-of-service, failure to start, and failure to run modes were further broken down into high-head and intermediate-head pump failure modes to provide additional insights into the reliability of the HPI system.

Additionally, the data associated with the maintenance-out-of-service failure mode were segregated according to plant operating mode. The maintenance events were categorized as to whether the reactor was critical or shut down at the time of the unplanned demand. For the unreliability estimates calculated, only the contribution of maintenance-out-of-service while the plant is operating (i.e., the reactor was critical) is included.

In calculating failure probabilities for the individual failure modes, the data were analyzed and tested (statistically) to determine if significant variability was present or if the data could be pooled. Each data set was modeled by simple Bayes method due to the sparseness of the data. In the simple Bayes method, the uncertainty in the calculated failure rate is dominated by random or statistical uncertainty (also referred to as *sampling* uncertainty). The simple Bayes method essentially pools the data and treats it as a homogeneous population. [For more information on this aspect of the data analysis, see Appendix A (Section A-2.1)].

3.1.1 Recovery of HPI Failures

Given that a failure has occurred in the HPI system, there exists an opportunity for the failure to be recovered. Specifically, the potential for failure recovery credited in this analysis is only for those events identified in the 1987–1997 experience where actual diagnosis and repair of HPI system are not required to make the system operational. Generally, the events listed in these categories require a simple activity such as restarting of the system if the automatic initiation circuitry did not start the system. Since these failures were not catastrophic (i.e., no corrective maintenance necessary), the estimates of HPI unreliability include the effects of recovery. However, due to the redundancy of the HPI system, if a train failed and the redundant train was successful, there might be no need to immediately attempt to recover the failed train. This type of failure was further analyzed to determine if the failed component could have been recovered. This potential for recovery was identified to prevent any bias in the recovery results. Figure 3 shows the outcomes of recovery based on the process used to review the 1987–1997 experience. The review of the 1987–1997 experience identified no instances where the human failed the recovery attempt where simple recovery was possible. Since, there were no events identified in the 1987–1997 experience for Path B (recovery was attempted but not successful), Path E (recovery was judged to be possible but would not have been successful) was assumed to have an outcome probability of zero.

3.1.2 Failure and Demand Counts used in the Unreliability Estimation

The failure and demand counts used for estimating probabilities for the HPI system failure modes are identified in Table 2. The demand counts identified in Table 2 represent opportunities for HPI system success. Due to the various designs and operational differences of the HPI system, a demand for HPI may

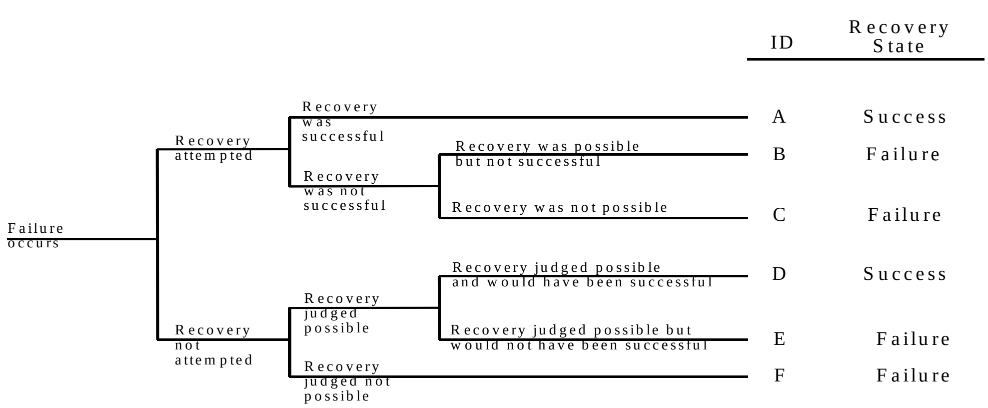


Figure 3. The recovery tree depicting the outcomes of recovering an HPI failure. The tree is based on the recovery actions observed in the unplanned demand data. Path B had no events of this type. Path E was assumed to have no likelihood based on Path B results.

Table 2. A summary of the HPI system/segment demands and associated independent failures identified in the unplanned demands.

Failure Mode	Unplanned Demands *f* [a]	Unplanned Demands *d* [a]	Quarterly Tests *f*	Quarterly Tests *d*
Failure to operate, train actuation faults (FTO-TRAIN)	1	410	—	—
Failure to recover, train actuation faults (FTO-TRAIN)	0(1)[b]	1(1)[b]	—	—
Maintenance-out-of-service while not shut down—high-head motor train (MOOS-CC)[c]	0	96	—	—
Failure to recover, high-head motor train maintenance MOOS-CC	0	0	—	—
Maintenance-out-of-service while not shut down—intermediate-head motor train (MOOS-SI)[c]	0	160	—	—
Failure to recover, intermediate-head motor train maintenance MOOS-SI	0	0	—	—
Failure to operate, suction path faults RWST-SUCT	0	168	0	9,261
Failure to recover, suction path faults RWST-SUCT	0	0	0	0
Failure to start, high-head pump/valve train path (FTS-CC)	0	145	—	—
Failure to recover from high-head motor FTS-CC	0	0	—	—
Failure to start, intermediate-head pump/valve train path (FTS-SI)	1	230	—	—
Failure to recover from intermediate-head motor FTS-SI	1(9)[b]	1(12)[b]	—	—
Failure to run, high-head pump/valve train path (FTR-CC)	0	145	—	—
Failure to recover, high-head pump/valve train path FTR-CC	0	0	—	—
Failure to run, intermediate-head pump/valve train path (FTR-SI)	0	229	—	—
Failure to recover, intermediate-head pump/valve train path FTR-SI	0	0	—	—
Failure to operate, injection/isolation header (FTO-INJ)	1	430	—	—
Failure to recover injection/isolation header FTO-INJ	1(5)[b]	1(5)[b]	—	—
Failure to operate, cold leg injection path (FTO-LOOP-INJ)	0	498	—	—

a. *f* denotes failures; *d* denotes demands.

b. The parenthetical values denote the additional failures identified for estimating the failure to recover probabilities. The additional failures were identified from data set B (refer to the Venn diagram depicted in Figure 2).

c. In this report, the MOOS contribution to HPI system unreliability was determined using those unplanned demand failures that resulted from the HPI system being unavailable for maintenance (test, preventive, or corrective) at the time of the demand.

require only a specific pipe segment of the system. No direct correlation of the segment demands to HPI system actuations is possible based solely on the information contained in the LERs. Therefore, piping diagrams and the design operation of the HPI systems (as documented in Final Safety Analysis Reports and Plant Information Books) were used, in conjunction with LERs, to determine the appropriate number of segment demands. The counts in Table 2 are summarized below:

- There were 227 unplanned SI actuations identified in the 1987–1997 experience. Of these, three occurred before the low-power license date and therefore are not counted. The net result is that 224 SI actuations formed the basis for the demand counts provided in Table 2. Due to the redundancy of the HPI system and plant conditions, 410 HPI train actuations resulted with one train failure reported. Due to the sparseness of the failure data, additional failure information was reviewed in order to reduce the uncertainty in the ability to recover from the failures. (The additional failures belong to the set B of the Venn diagram depicted in Figure 2 of Section 2.3.) Based on this additional information, the failure to recover probability was based on two failures with one not being recoverable.

- For the high-head pump train, there were 96 demands that resulted in no trains being out of service for maintenance at the time of the demand. Similarly, for the intermediate-head pump train, no out-of-service failures occurred in 160 demands.

- The suction segment provides the source of water, typically from the Refueling Water Storage Tank, to the HPI pump trains during the injection phase. There were 168 unplanned demands for the suction segment to supply water to a pump train. No failures were identified for the suction segment. Due to sparseness of unplanned demand data associated with the RWST, test data was used in addition to the unplanned demand data. Based on quarterly surveillance testing of the high-pressure safety injection, low-pressure safety injection, and containment spray systems, no failure of the RWST was identified in the 1987–1997 experience. There were 9,261 quarterly test demands estimated for this study's time period.

- There were 145 opportunities for a high-head motor train to start due to unplanned demands. No failures were identified.

- There were 230 opportunities for an intermediate-head motor train to start due to unplanned demands. These demands resulted in one failure to start of an intermediate-head motor train. Based on the review of additional information contained in the HPI inoperable events, a total of thirteen failures of the intermediate-head motor train were noted with ten not being recoverable.

- For the run phase of the HPI system operation, there were no failures of the high-head motor train in the 145 unplanned demands. For the intermediate-head motor train, no failures to run were observed in the 229 demands.

- The injection headers downstream of the pump/valve trains received an estimated 430 opportunities to direct/control flow to a cold leg injection path. Of the injection header demands, one failure to operate was identified within this pipe/valve segment. Based on the review of additional information contained in the HPI inoperable events, six failures of this HPI piping segment were noted. The six failures were not recoverable.

- The cold leg injection path segment consists of the piping segment downstream of the injection headers and immediately upstream of the cold leg. There were 498 demands experienced by this segment from the unplanned demands. No failures occurred.

3.1.3 Modeling of Common Cause Failures

Due to the redundant characteristics of the HPI pump trains, injection headers and cold leg injection paths, common cause failures (CCFs) were considered. CCF was explicitly included in the HPI unreliability model because CCF events were found in HPI failure data between 1987–1997. (The CCFs were identified in data set B in the Venn diagram of Figure 2.) The following paragraphs summarize the basis for the type of CCF events evaluated, the method of estimating CCF basic event probabilities used in the system model, and a comparison of the selected method and raw data estimates. Section D-1 of Appendix D provides further details of the CCF analysis.

CCF data collection and analysis of the HPI system was conducted in several stages and accomplished in conjunction with the CCF Database[50] program. First, the LERs (unplanned demand, surveillance test, and inoperable events for the 1987–1997 time frame) were screened for identification of CCF modes and basic events to be included in the fault tree analyses. The CCF analysis of the HPI system included events identified in the 1987–1997 time period that contributed to failure of redundant segments. Based on the 1987–1997 unplanned SI actuation demand data, no CCF events were identified. To further evaluate the susceptibility of HPI to CCF, the data contained in the remaining LERs were screened to identify any potential CCF mechanisms. CCF events were identified in the set of data for the high-head pump trains failing to start and run, intermediate-head pump trains failing to start and run, and the injection headers failing to operate. No CCF failures were identified across the high-and intermediate-head pump systems in the 1987–1997 experience.

The alpha factor method, which is supported by the CCF Data Collection and Analysis System (see Reference 50), was selected to estimate the CCF contribution of the failure modes identified during the CCF screening step. This method was selected because it: (1) fits the HPI system study needs, and (2) supports an uncertainty analysis by estimating CCF uncertainties. The alpha factors calculated from the CCF Data Collection and Analysis System are presented in Table 3. In addition to the CCF failure modes identified in the 1987–1997 experience, the alpha factors for the aggregated high- and intermediate-head failing to start as well as failing to run are included in Table 3. (These events in Table 3 are labeled as ALPHA-FTS-HPI and ALPHA-FTR-HPI, respectively.) Although there were no CCF failures identified across the high-and intermediate-head pump systems in the 1987–1997 experience, the estimates are intended to provide the reader and user of this document with a consistent set of CCF parameters for the HPI systems for the time period of this study.

The HPI system study modeled only the “global” CCFs. That is, if only one pump is needed to operate in a system that has 3 pump trains, CCFs that fail only 2 out of the three pumps were not considered. Only the global CCF (common cause failure that fail all 3 pumps) was modeled. Even though this introduces a potential for error due to exclusion of system cut sets that contain non-global CCFs and random failures, that error was negligible. For example, in the case South Texas Project, the global CCF is 5.4E-05. In comparison, the combinations of non-global CCFs and random failures resulted in cut sets of the order of 1E-07.

The CCF of check valves was not modeled in the HPI model, even though the potential for this CCF is identified in the CCF database[50] and IPE/PRAs. In system studies, in general, only those CCFs whose potential have revealed them selves within the operating experience collected (both unplanned demands or other failures) are modeled. During the 1987–1997 period, there were no HPI-related CCFs involving check valves. Furthermore, compared to the other CCFs and random failures modeled, the magnitude of the check valve CCFs would be relatively small and as a result, their contribution to the system unreliability would be negligible.

Table 3. Estimates of alpha factors based on the 1987–1997 experience used for calculating the HPI unreliability.

Event Name	Distribution	Alpha Factor Mean and 90% Interval	Description
ALPHA-FTS-CC	Beta(2.49, 3.70E+01)	(1.5E-03, 6.3E-02, 1.4E-01)	2 of 2 high-head pumps fail to start
ALPHA-FTS-CC	Beta(1.66, 5.68E+01)	(4.0E-03, 2.8E-02, 7.1E-02)	3 of 3 high-head pumps fail to start
ALPHA-FTS-SI	Beta(1.89, 5.04E+01)	(6.1E-03, 3.6E-02, 8.6E-02)	2 of 2 intermediate-head pumps fail to start
ALPHA-FTS-SI	Beta(1.41, 7.68E+01)	(1.9E-03, 1.8E-02, 4.8E-02)	3 of 3 intermediate-head pumps fail to start
ALPHA-FTS-SI	Beta(1.48, 1.07E+02)	(1.6E-03, 1.4E-02, 3.6E-02)	4 of 4 intermediate-head pumps fail to start
ALPHA-FTS-HPI[a]	Beta(3.90, 7.79E+01)	(1.6E-02, 4.7E-02, 9.1E-02)	2 of 2 safety-injection pumps fail to start
ALPHA-FTS-HPI[a]	Beta(2.66, 1.18E+02)	(5.4E-03, 2.2E-02, 4.7E-02)	3 of 3 safety-injection pumps fail to start
ALPHA-FTS-HPI[a]	Beta(2.61, 1.61E+02)	(3.8E-03, 1.6E-02, 3.4E-02)	4 of 4 safety-injection pumps fail to start
ALPHA-FTR-CC	Beta(1.15, 7.25E+01)	(1.1E-03, 1.6E-02, 4.4E-02)	2 of 2 high-head pumps fail to run
ALPHA-FTR-CC	Beta(0.57, 1.10E+02)	(3.8E-05, 5.1E-03, 1.9E-02)	3 of 3 high-head pumps fail to run
ALPHA-FTR-SI	Beta(3.71, 4.56E+01)	(2.5E-02, 7.5E-02, 1.4E-01)	2 of 2 intermediate-head pumps fail to run
ALPHA-FTR-SI	Beta(2.89, 6.97E+01)	(1.1E-02, 4.0E-02, 8.3E-02)	3 of 3 intermediate-head pumps fail to run
ALPHA-FTR-SI	Beta(2.74, 9.67E+01)	(7.0E-03, 2.8E-02, 5.9E-02)	4 of 4 intermediate-head pumps fail to run
ALPHA-FTR-HPI[a]	Beta(4.39, 1.10E+02)	(1.4E-02, 3.8E-02, 7.2E-02)	2 of 2 safety-injection pumps fail to run
ALPHA-FTR-HPI[a]	Beta(3.04, 1.65E+02)	(5.0E-03, 1.8E-02, 3.7E-02)	3 of 3 safety-injection pumps fail to run
ALPHA-FTR-HPI[a]	Beta(2.84, 2.23E+02)	(3.2E-03, 1.2E-02, 2.6E-02)	4 of 4 safety-injection pumps fail to run
ALPHA-INJ-HDR	Beta(2.85, 4.72E+01)	(1.5E-02, 5.6E-02, 1.1E-01)	2 of 2 injection header valves fail to operate
ALPHA-INJ-HDR	Beta(2.47, 7.20E+01)	(7.6E-03, 3.3E-02, 7.2E-02)	3 of 3 injection header valves fail to operate
ALPHA-INJ-HDR	Beta(2.49, 1.00E+02)	(5.6E-03, 2.4E-02, 5.3E-02)	4 of 4 injection header valves fail to operate
ALPHA-INJ-HDR	Beta(2.65, 1.63E+02)	(3.9E-03, 1.6E-02, 3.4E-02)	6 of 6 injection header valves fail to operate
ALPHA-INJ-HDR	Beta(2.92, 2.47E+02)	(3.1E-03, 1.2E-02, 2.5E-02)	8 of 8 injection header valves fail to operate

a. The estimate is based on the aggregated experience for the high- and -intermediate-head pumps (e.g: FTS-CC and FTS-SI).

Class specific differences in CCF were taken into account by differentiating between the CCFs between charging (high-head) pumps used for high-pressure injection versus the intermediate-head pumps. That is, the common cause events were screened to group them by high head versus intermediate and different alpha factors were calculated for the two pump groups. Due to sparseness of data, there was no benefits to screen events to create other class specific alpha factors. Even though the CCF database (Ref. 50) provides the capability to customize data, this capability was used to create alpha factor distributions that are based on plant-to-plant variability. Again, due to sparseness of data, that capability was not used.

3.1.4 HPI System Fault Tree Models

The fault tree models for the six design classes shown in Figure 4 illustrate the logic used for generating the 72 plant-specific HPI unreliability models (injection phase only). Plant-specific models were generated since there are some HPI design and operation differences within a design class. These differences are described in Section D-2 of Appendix D.

3.2 HPI Unreliability

This section documents the results of the reliability analyses performed using the 1987–1997 HPI experience. Estimates of HPI unreliability for the actual missions experienced were calculated. These unreliability estimates are based on the operational events that result from a SI actuation signal (manual or automatic) and a demand for high-pressure safety injection. These events for HPI operation can range from a few minutes to a few hours.

3.2.1 HPI System Modeling Assumptions

The fault tree models for the six design classes shown in Figure 4 provided the logic used for generating the 72 plant-specific HPI unreliability models. The six HPI design class models were developed to categorize the levels of cold leg and pump train redundancy and diversity (high-head and intermediate-head) across the industry. The steam generator criterion was used for a matter of convenience instead of the number of cold legs. The number of cold legs is correlated to the number of steam generators. The steam generator criterion reduced the number of possible groupings of HPI design. Plant-specific models were developed from the six models to identify injection header/cold leg path redundancy and operational differences within a design class. These differences are described later in Section 3.2.4. The unreliability of the HPI system was calculated using the plant-specific fault tree models. The models were constructed to reflect the failure modes identified in the unplanned demand data and the levels of redundancy and diversity of the HPI piping segments. In most cases, the fault tree models used the small LOCA success criteria stated in the PRA/IPEs (refer to Table 1 for the success criteria). However, the success criterion for several plants was modified to eliminate the non-safety class pump trains modeled in some PRA/IPEs. Failures are not reportable for these types of pump trains. Therefore, estimates for these types of non-safety components were not calculated. Further, the success logic was modified to account for the in-line spare pump that required operator actions to place the spare HPI pump in service (e.g: reconnecting the spare pump to an electrical bus).

The failure of the RWST suction path was modeled and it was the dominant failure for HPI Design Class 6 plants although there were no failures in the unplanned demand data extracted from the 1987–1997 experience. The failure mode associated with this segment was included as the dominant failure in the quantification because of the following reasons:

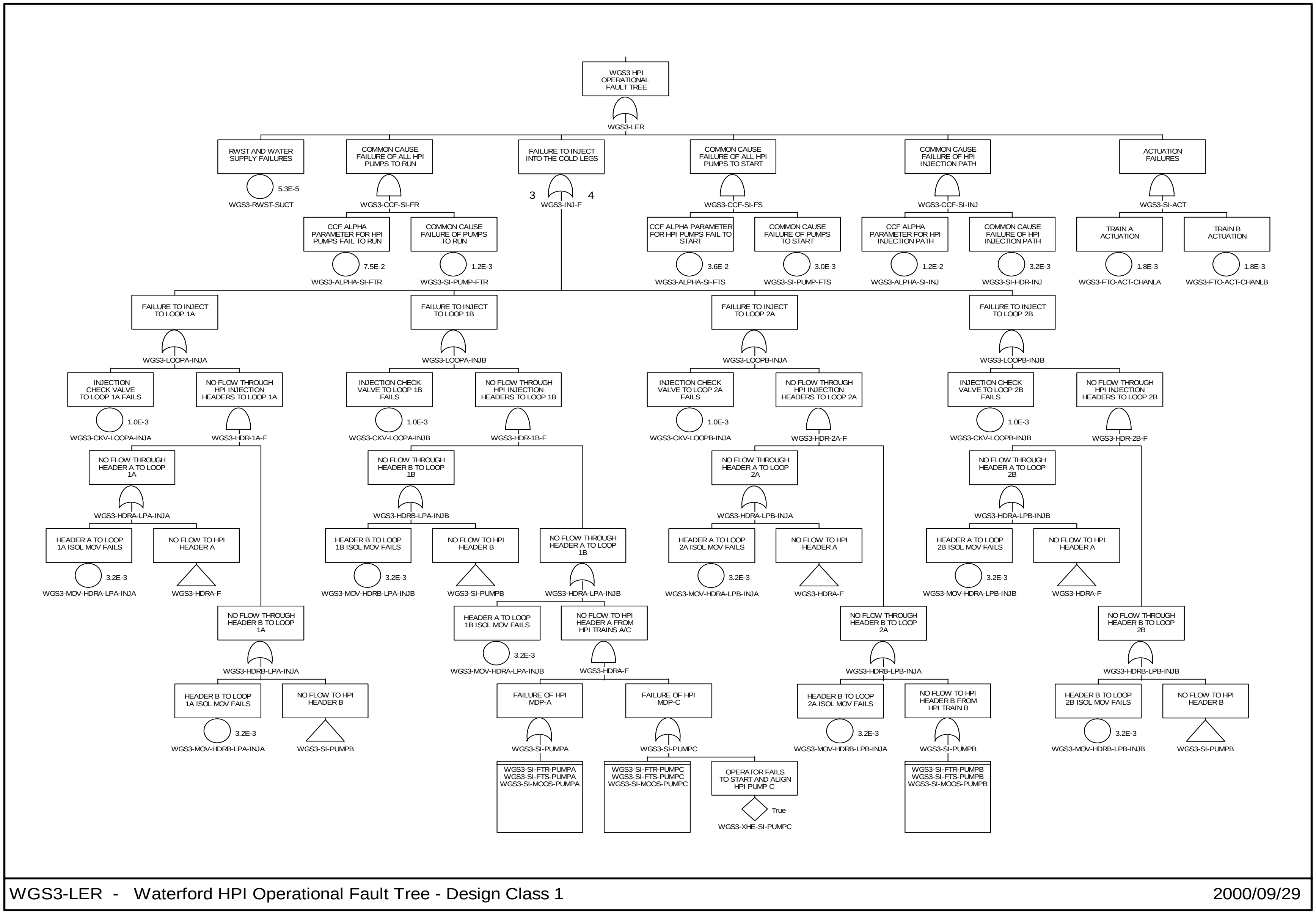


Figure 4. System fault trees of the six HPI (injection phase) design classes used in calculating unreliability.

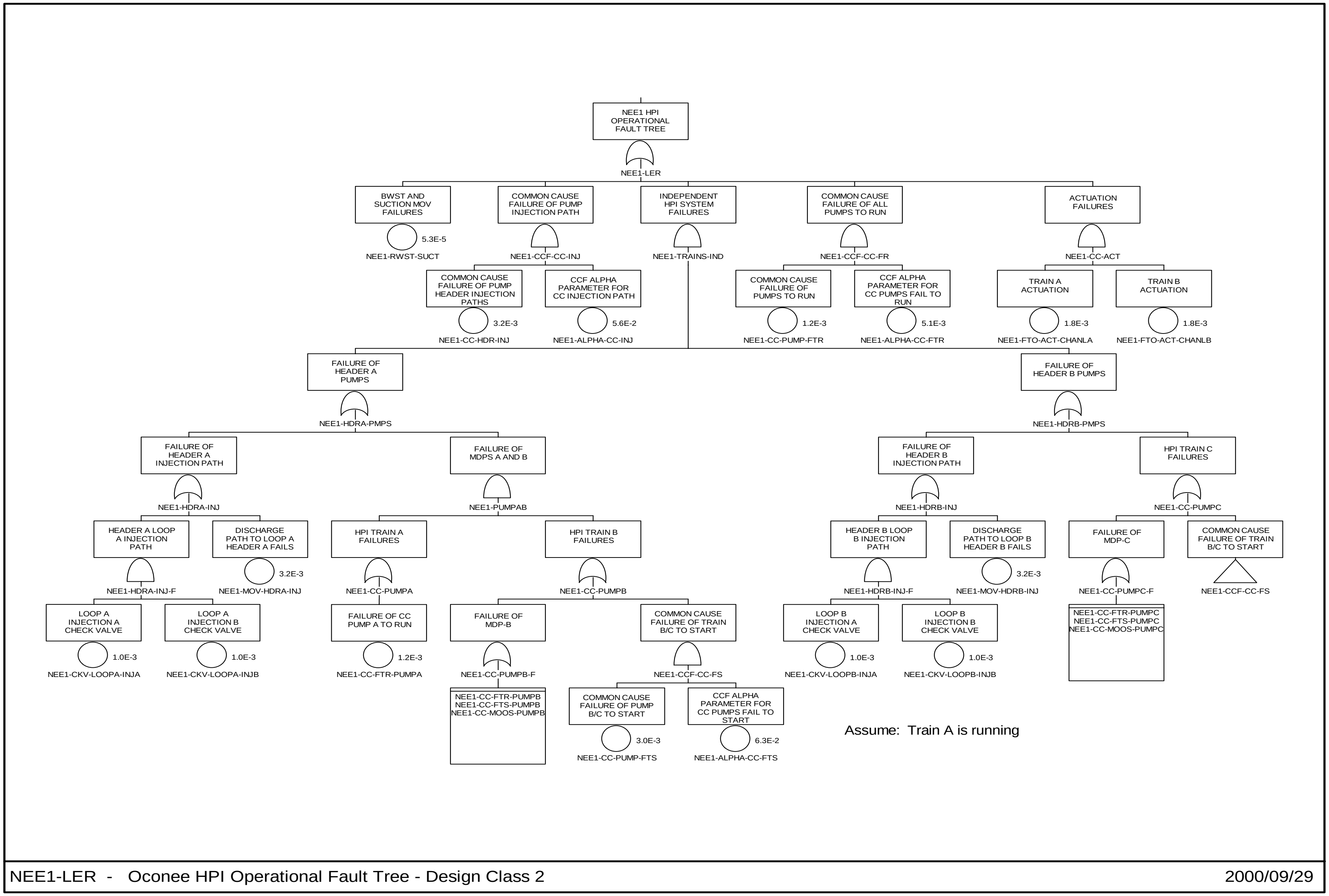


Figure 4. (continued).

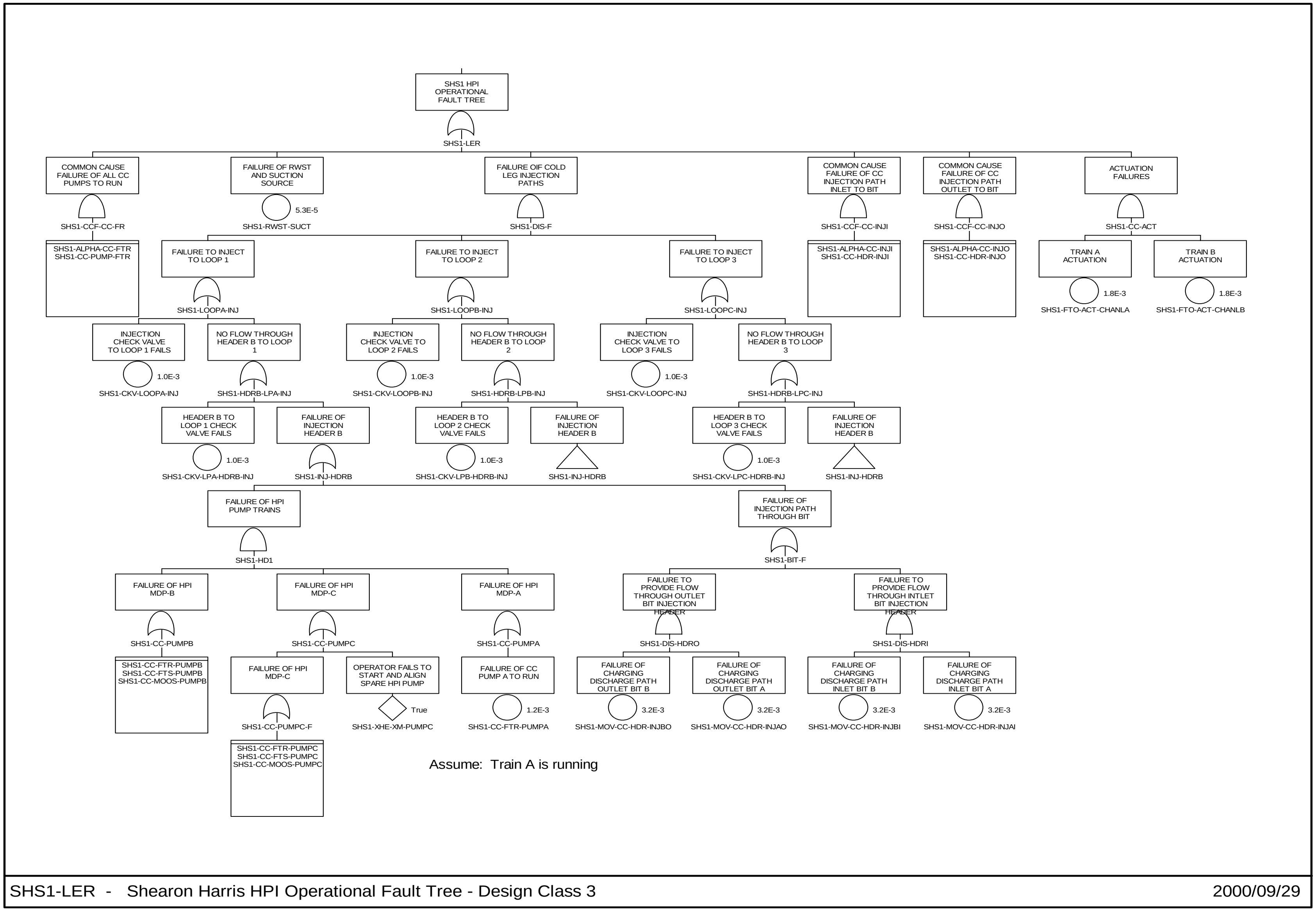


Figure 4. (continued).

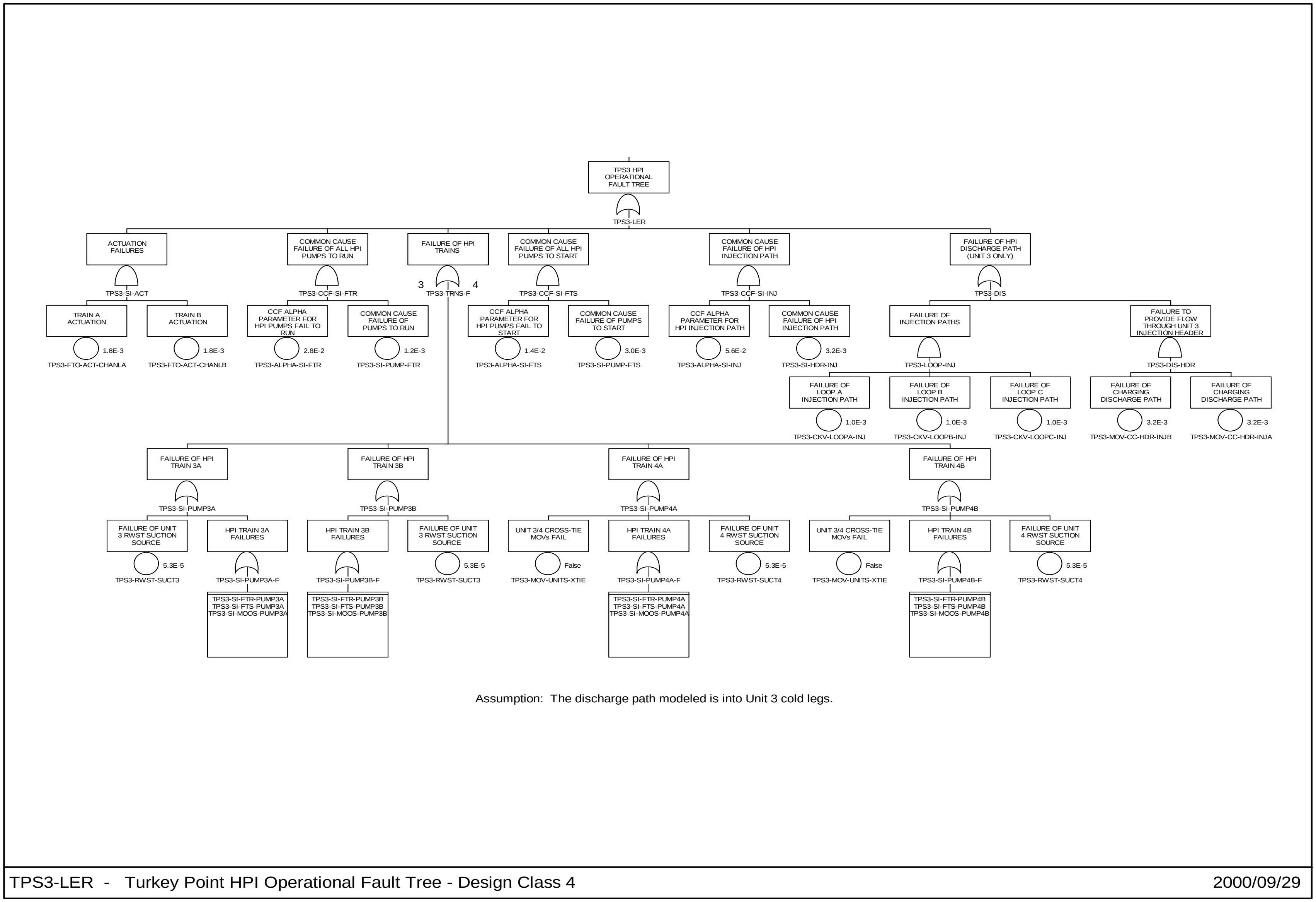


Figure 4. (continued).

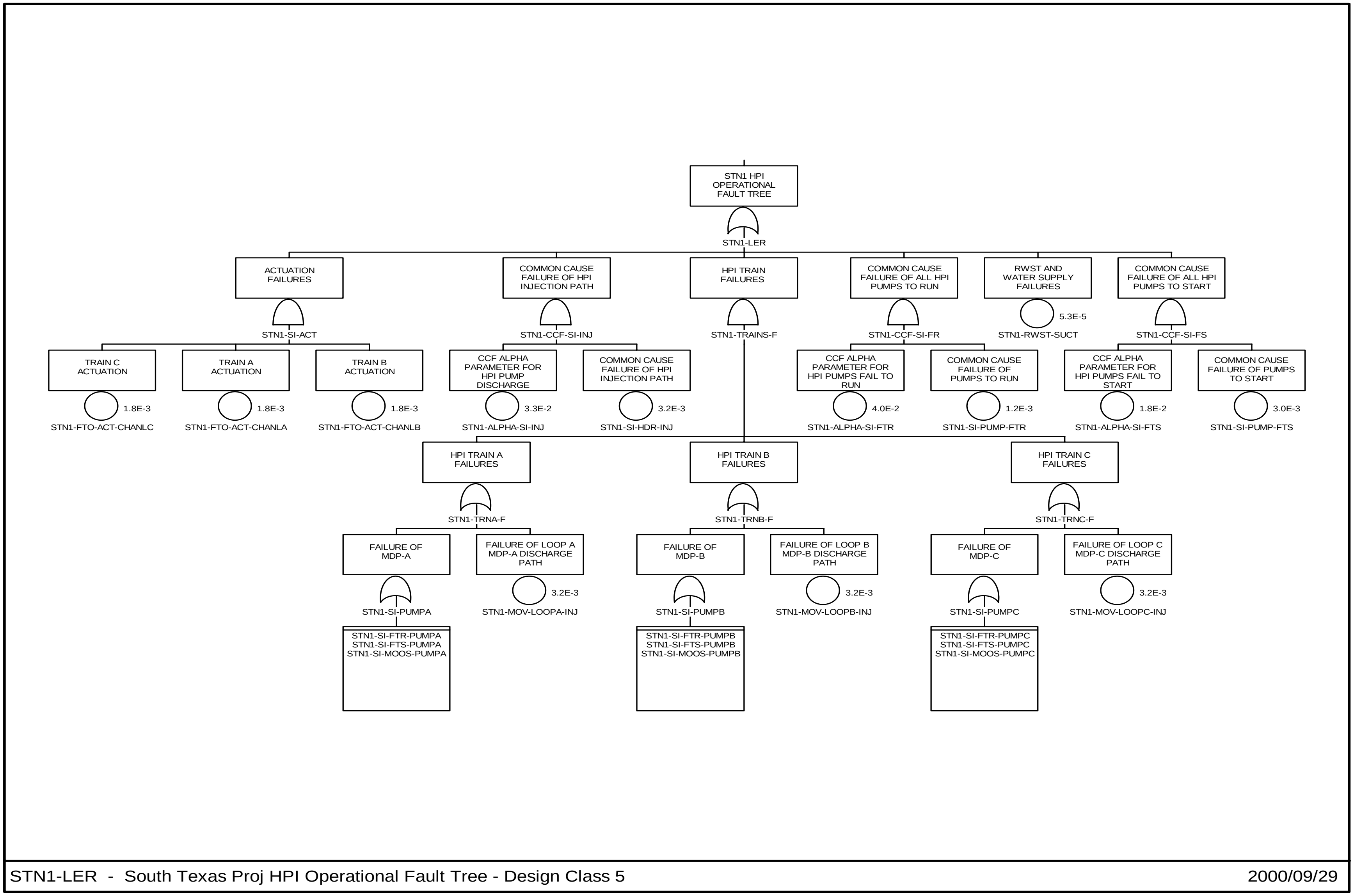


Figure 4. (continued).

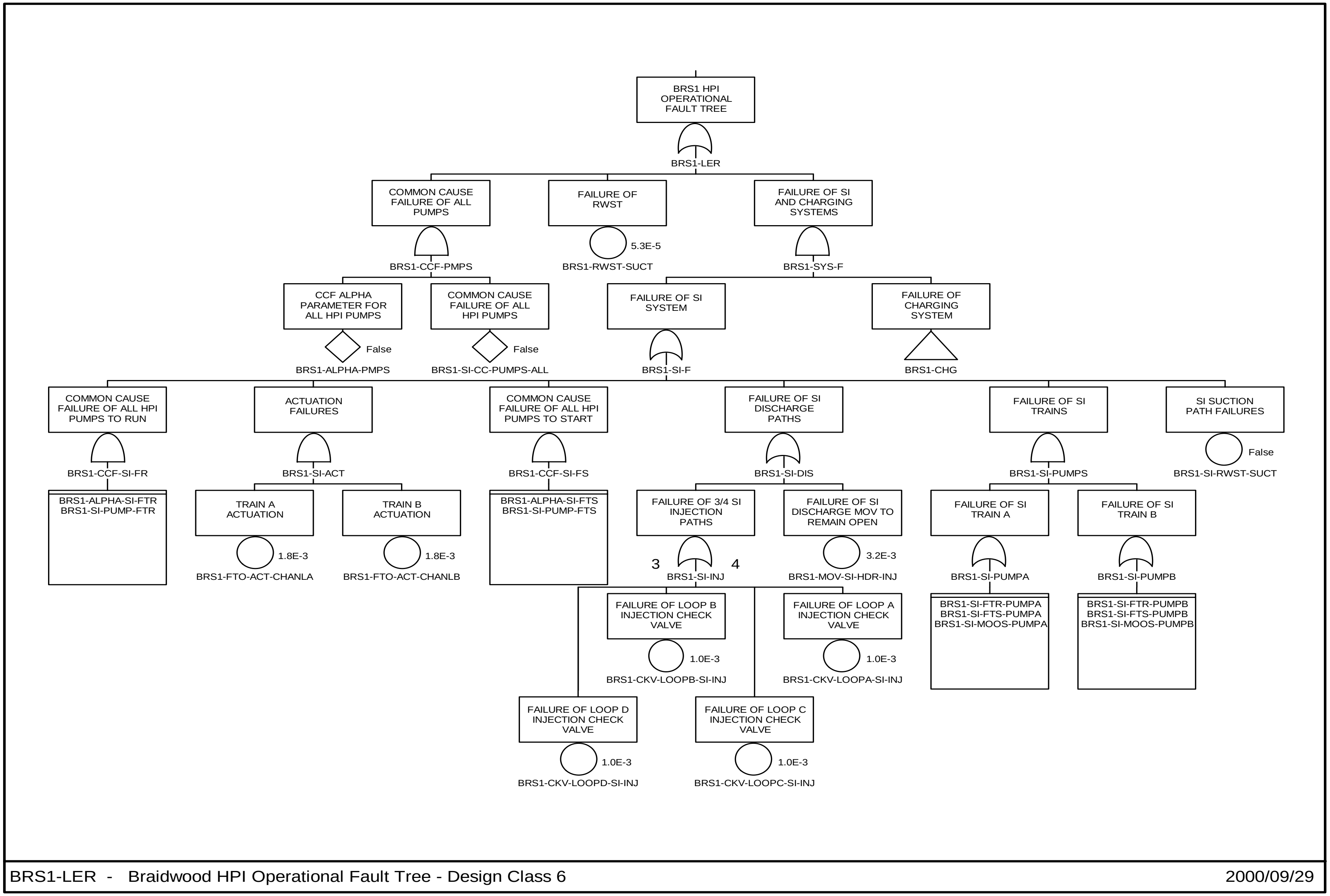
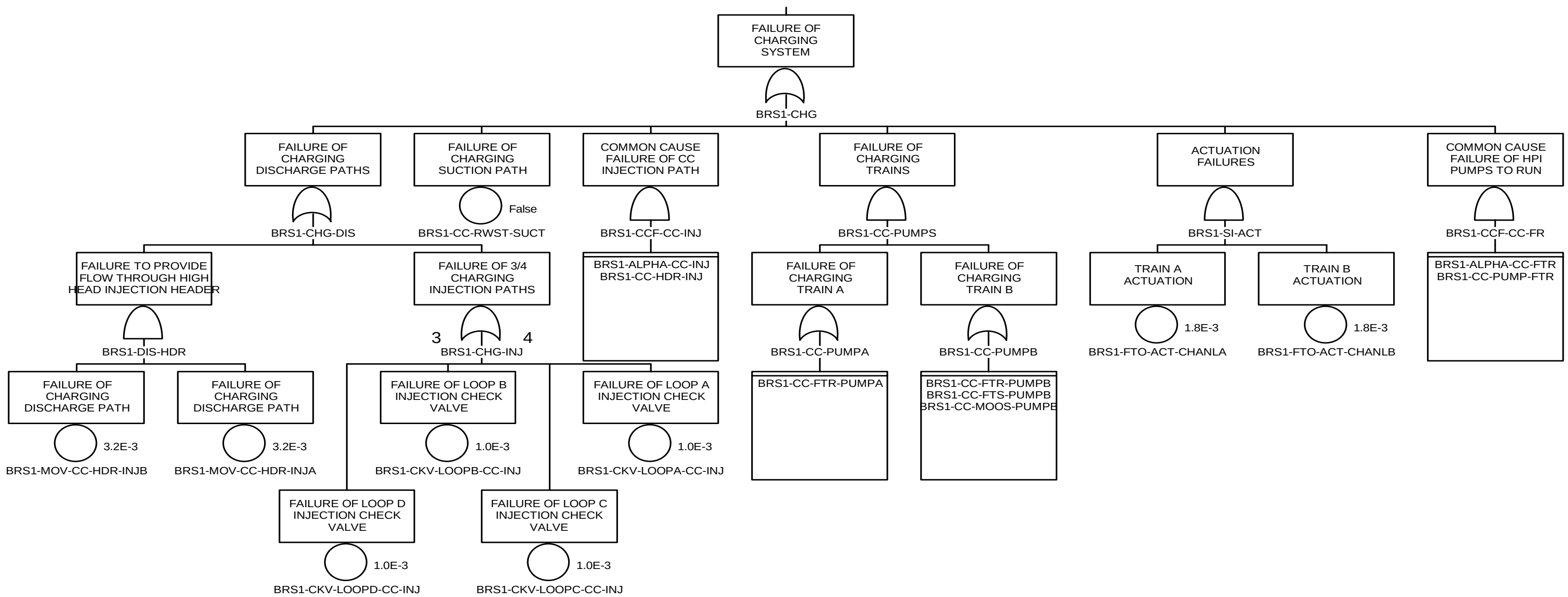


Figure 4. (continued).



BRS1-CHG - Braidwood HPI Charging System Operational Fault Tree 2000/09/29

Figure 4. (continued).

- Although no complete failure of this segment was observed in the unplanned demand data for this segment, partial failures of the RWST suction path identified in the 1987–1997 experience tends to support this failure mode as being credible. Even though this failure dominates Design Class 6, the failure probability estimated for this segment is low, about 5E-05.

- Design Class 6 uses redundancy (four or five pump trains and eight injection paths) and diversity (high-head and intermediate-head pumps) in the HPI systems. Because of these features, it is reasonable for the RWST suction segment (this is the shared between high and intermediate subsystems) to have a major effect on HPI unreliability.

Estimates of HPI unreliability were calculated using the 1987–1997 experience using only the unplanned demand data. These data were statistically analyzed to develop failure probabilities (see Appendix A for the details on the statistical applications and methods). The following failure modes are based on the 1987–1997 experience (based on the unplanned demand data):

- Maintenance-out-of-service—Pump, driver, valves, and associated piping (MOOS)

- Failure to Operate: Train Actuation—High-Pressure Safety Injection (SI) actuation channels (FTO-ACT)

- Failure to Start—Pump, driver, valves and associated piping (FTS)

- Failure to Run—Pump, driver, valves and associated piping (FTR)

- Failure to Operate—Injection header valves (HPI isolation, etc.) and associated piping faults (FTO-INJ)

- Failure to Operate—Loop (cold leg) injection paths and associated piping faults (FTO-LOOP-INJ).

- Failure to Operate—RWST suction path and associated piping faults (FTO-RWST-SUCT).

Table 4 contains the failure mode probabilities and associated uncertainty intervals calculated from the 1987–1997 experience for the independent failures. Table 3 provides the estimates for the alpha factors ($\alpha_{k/n}$) used in the CCF quantification. The following conditions were assumed for the purposes of quantifying the operational mission fault tree:

- A demand (SI actuation), whether actual or inadvertent, to provide high-pressure safety injection to a cold leg is received by the HPI system.

- The only mode of HPI modeled is the injection phase. Alternate suction sources were not modeled. Further, the long-term recirculation mode of HPI is not modeled.

3.2.2 Estimates of HPI Unreliability and Insights

Between-plant differences in HPI unreliability exist due to the design variations and due to operational variations of the HPI systems within certain design classes. Therefore, plant-specific estimates were calculated. A plot of the plant-specific estimates of HPI unreliability calculated using the 1987–1997 experience is provided in Figure 5. The plant-specific estimates are grouped according to HPI design class. The average of the 72 plant-specific estimates of HPI unreliability is approximately

Table 4. HPI system failure mode data and Bayesian probability information for estimating unreliability. The common cause alpha factors are presented in Table 3.

Failure Mode[a]	f[b]	d[b]	Modeled Variation	Distribution	Bayes[e] Mean and 90% Interval[c]
Maintenance-out-of-service while not shut down — high-head train (MOOS-CC)	0	96	Sampling	Beta(0.5, 96.5)	(2.0E-05, 5.2E-03, 2.0E-02)
Maintenance-out-of-service while not shut down — intermediate-head train (MOOS-SI)	0	160	Sampling	Beta(0.5, 160.5)	(1.2E-05, 3.1E-03, 1.2E-02)
Maintenance-out-of-service while not shut down — (Combined CC and SI)	0	256	Sampling	Beta(0.5, 256.5)	(7.7E-06, 1.9E-03, 7.5E-03)
Unrecovered FTO-ACT-CHANL			Sampling	Beta(0.92, 505.4)	(7.6E-05, 1.8E-03, 5.6E-03)
Failure to operate, train actuation — (FTO-ACT-CHANL)	1	410	Sampling	Beta(1.5, 409.5)	(4.3E-04, 3.6E-03, 9.5E-03)
Failure to recover from FTO-ACT-CHANL	1	2	Sampling	Beta(1.5, 1.5)	(9.7E-02, 5.0E-01, 9.0E-01)
Failure to operate, suction path faults RWST-SUCT	0	9,429	Sampling	Beta(0.5, 9429.5)	(2.1E-07, 5.3E-05, 2.0E-04)
Failure to start, high-head pump/valve train path — (FTS-CC)	0	145	Sampling	Beta(0.5, 145.5)	(1.4E-05, 3.4E-03, 1.3E-02)
Unrecovered FTS-SI			Sampling	Beta(1.17, 240.0)	(3.6E-04, 4.9E-03, 1.4E-02)
Failure to start, intermediate-head pump/valve train path — (FTS-SI)	1	230	Sampling	Beta(1.5, 229.5)	(7.7E-04, 6.5E-03, 1.7E-02)
Failure to recover from FTS-SI	1	1	Sampling	Beta(1.5, 0.5)	(2.3E-01, 7.5E-01, 1.0E+00)
Unrecovered FTS (Combined CC and SI pumps)			Sampling	Beta(1.4, 474.2)	(3.2E-04, 3.0E-03, 7.9E-03)
Failure to start, HPI pump/valve train path — (FTS-HPI)	1	375	Sampling	Beta(1.5, 374.5)	(4.7E-04, 4.0E-03, 1.0E-02)
Failure to recover from FTS-HPI	10	13	Sampling	Beta(10.5, 3.5)	(5.5E-01, 7.5E-01, 9.1E-01)
Failure to run, high-head pump/valve train path — (FTR-CC)	0	145	Sampling	Beta(0.5, 145.5)	(1.4E-05, 3.4E-03, 1.3E-02)
Failure to run, intermediate-head pump/valve train path — (FTR-SI)	0	229	Sampling	Beta(0.5, 229.5)	(8.6E-06, 2.2E-03, 8.3E-03)
Failure to run, pump/valve train path (Combined CC and SI pumps) — FTR-HPI	0	202[d]	Sampling	Gamma(0.5, 202hrs)	(9.9E-06, 2.5E-03, 9.5E-03)[d]
Unrecovered FTO-INJ			Sampling	Beta(1.47, 451.9)	(3.7E-04, 3.2E-03, 8.5E-03)
Failure to operate; injection header — (FTO-INJ)	1	430	Sampling	Beta(1.5, 429.5)	(4.1E-04, 3.5E-03, 9.1E-03)
Failure to recover; injection header FTO-INJ	6	6	Sampling	Beta(6.5, 0.5)	(7.4E-01, 9.3E-01, 1.0E+00)
Failure to operate: loop injection path— (FTO-LOOP-INJ)	0	498	Sampling	Beta(0.5, 498.5)	(3.9E-06, 1.0E-03, 3.8E-03)

a. The shaded rows represent the failure modes included in the fault tree quantification of HPI unreliability. The unshaded rows represent failure modes that had sparse data and including these estimates in the unreliability quantification may provide misleading results. The unshaded rows are provided to the reader as additional information.
b. *f* denotes failures; *d* denotes demands.
c. The values in parentheses are the 5% uncertainty limit, the Bayes mean, and the 95% uncertainty limit.
d. The values presented are based on the estimated run hours of pump operation during an unplanned actuation. The failure to run estimates presented are hourly failure rates.
e. Jeffreys noninformative prior was used for the Bayesian update.

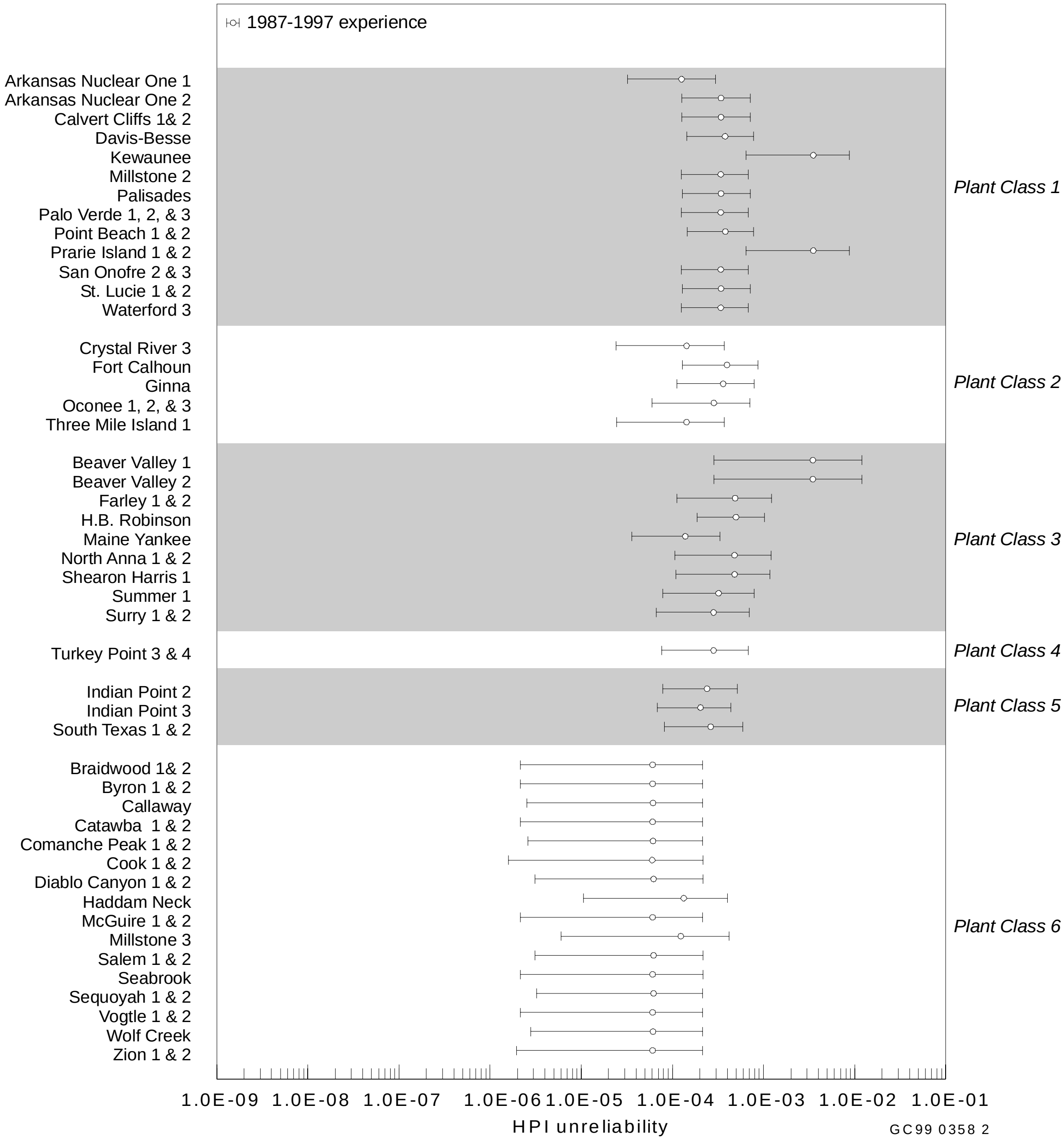


Figure 5. Plant-specific estimates of HPI system unreliability (injection phase only) grouped by design class. The mean and uncertainty values associated with this plot are listed in Table D-3 in Appendix D.

4.5E-04. The range of the 72 plant-specific estimates is 6.0E-05, 3.5E-03. The arithmetic average, which is based on the plant-specific estimates derived from fault tree methodology, was compared to a simple system (complete) performance estimate calculated directly by using a Jeffreys noninformative prior. The overall system reliability estimate is 2.2E-03 (based on no total system failures in 224 SI demands). The 90% uncertainty interval on the Jeffreys estimate is (8.9E-06, 8.6E-03). The plant-specific mean estimates fall within the 90% uncertainty interval calculated for the overall system reliability estimate.

The contributions of failures to the overall HPI unreliability are presented in Table 5. The contributions are calculated according to the cut set contribution to the unreliability for the reference plant selected for each design class. (Table D-6 provides the listing of the cut sets for the six reference plants.) Based on the average of the six reference plants, CCF is the leading contributor to the unreliability.

Table 5. HPI system cut set contribution (for the reference plant in each design class) to unreliability (injection phase only).

HPI Design Class	Reference Plant Unreliability (Mean)	Contribution (%) To Unreliability	
		Multiple Independent Failures	Common Cause Failure
1—(2 HHSI or 2 IHSI; 2 SGs)	3.4E-04	27	73
2—(3 HHSI or 3 IHSI; 2 SGs)	2.9E-04	28	72
3—(2 HHSI or 2 IHSI; 3 SGs)	4.8E-04	18	82
4—(4 IHSI; 3 SGs)	2.8E-04	5	95
5—(3 IHSI; 4 SGs)	2.6E-04	20	80
6—(2 HHSI, 2 IHSI; 4 SGs)	6.1E-05	99	1

Generally, the importance of CCF is typical of redundant train systems that are highly reliable.) Based on HPI unreliability, HPI systems consisting solely of intermediate-head or high-head trains are more likely to fail as a result of CCF. While HPI systems consisting of two high-head and two intermediate-head trains are more likely to fail as a result of random failures of the common RWST suction segment.

3.2.3 HPI Unreliability Across Design Classes

Table 6 contains the arithmetic average of HPI unreliability with regard to design class. These results indicate that variability across the HPI system designs exists. The design class average unreliability ranges from 5.6E-05 (Design Class 6) to 9.1E-04 (Design Class 3). HPI designs consisting of only two pump trains are the least reliable, while designs incorporating four diverse pump trains are the most reliable.

The 1987–1997 HPI operational experience includes zero total system failures and a total of three HPI segment failures. Due to the sparseness of the data, between-plant variation of failure probabilities could not be calculated at the HPI segment level. For example, for all plants, an identical value was used for the failure to start probability of a pump train. In spite of using identical failure probabilities, there are significant differences in the plant-specific HPI unreliabilities calculated using the operating experience.

Table 6. Average design class unreliability (injection phase only) calculated from the 1987–1997 experience.

HPI Design Class	Number of Plants	Average[a] Design Class Unreliability
1 — (2 HHSI or 2 IHSI; 2 SGs)	20	8.1E-04
2 — (3 HHSI or 3 IHSI; 2 SGs)	7	2.7E-04
3 — (2 HHSI or 2 IHSI; 3 SGs)	12	9.1E-04
4 — (4 IHSI; 3 SGs)	2	2.8E-04
5 — (3 IHSI; 4 SGs)	4	2.4E-04
6 — (2 HHSI, 2 IHSI; 4 SGs)	27	6.6E-05
		overall average[a] — 4.5E-04

a. The values are arithmetic averages.

This is attributed to major differences in design (number of pump trains, etc.) and operation (number of normally operating pumps) among the HPI systems.

Even though all random failure probabilities were based on three failures, the HPI unreliabilities were dominated by CCFs. Therefore, alpha factors, and all the CCF failure events that contributed to the generation of the alpha factors, significantly influenced the unreliability estimates calculated using the 1987–1997 HPI operational experience.

3.2.4 Within-Design-Class Differences

The differences within design class shown in Figure 5 are attributed to the variations of HPI systems within a design class and to some degree the success criteria postulated by some plants. Differences within a design class due to system configuration are possible since the HPI design classes were categorized first by number of steam generators (SGs) (which correlates to cold legs) and then by number of HPI pump trains. These differences are discussed below.

Design Class 1 (2 HHSI or 2 IHSI, 2 SGs). The system configuration modeled in Design Class 1 is essentially two pump trains that require one train for success. Generally, the injection header configurations provide redundant injection header paths and redundant injection paths per cold leg. However, two configurations (Kewaunee and Prairie Island 1&2) have the pump trains discharge into a common injection header and only one injection path per cold leg. The HPI unreliability for this configuration is higher by about a factor of ten than for the remaining plants within this HPI design class.

The lower HPI unreliability of Arkansas Nuclear One 1 is primarily due to the operational running high-head pump as compared to the standby intermediate-head pumps of the remaining HPI configurations of Design Class 1. The running high-head pump eliminates the CCF mechanism of failing to start. Further, the alpha factor for the high-head pumps failing to run is smaller by a factor of four than the corresponding alpha factor for the intermediate-head pumps.

Design Class 2 (3 HHSI or 3 IHSI, 2 SGs). The variation in HPI unreliabilities seen within this design class is mainly attributed to the redundancy levels associated with the injection paths to the cold legs, the use of high-head versus intermediate-head pumps, and the success criteria for the injection phase. Crystal River 3 and Three Mile Island 1 HPI configurations were below the design class average. The lower HPI unreliabilities calculated for these two plants are primarily due to the operational running high-head pump as compared to the standby intermediate-head pumps of the HPI configurations of Design Class 2. The running high-head pump eliminates the CCF mechanism of failing to start. Further, the alpha factor for the high-head pumps failing to run is smaller by a factor of four than the corresponding alpha factor for the intermediate-head pumps. This resulted in the HPI configurations at Ginna and Ft. Calhoun to have higher than average HPI unreliabilities within this design class.

Although Oconee has high-head pumps with one pump running, similar to Crystal River 3 and Three Mile Island 1, there is a lesser number of redundant injection headers at Oconee, thereby resulting in a higher CCF likelihood.

Design Class 3 (2 HHSI or 2 IHSI, 3 SGs). The system configuration modeled in Design Class 3 is two pump trains that require one train for success. (Note that this class of HPI systems has a third pump that requires operator action to be put on line. Spare HPI pumps that require operator action to place in service are not credited in this analysis.) Generally, the injection header configurations provide redundant injection header paths and redundant injection paths per cold leg. The plants (Beaver Valley 1&2) resulted in the highest unreliability within this design class. This is attributed to the success criterion that requires three-of-three cold legs for the injection phase. The HPI unreliability for this configuration is higher by about a factor of seven than the remaining plants within this HPI design class. The HPI design at Maine Yankee resulted in a lower unreliability (by about a factor of five) than the majority of plants in this design class. The lower unreliability is primarily due to additional levels of redundancy in the injection headers and the injection paths per cold leg at Maine Yankee.

Design Class 4 (3 IHSI, 3 SGs). There is only one unit, Turkey Point 3&4, with this configuration.

Design Class 5 (3 IHSI, 4 SGs). There are only four plants with this configuration and all of the HPI unreliabilities are in good agreement. The South Texas plants have a slightly higher unreliability that is attributed to one less cold leg available for injection (three versus four) than the other configurations within this design class.

Design Class 6 (2 HHSI, 2 IHSI, 4 SGs). There is a slight difference between two system configurations in Design Class 6. The difference is attributed to the operational aspect of the high-head pumps. One configuration has a high-head motor pump train is running, while the remaining high-head pump train is in standby. The other configuration has both high-head pump trains in standby mode. (For the one running and one standby configuration, only the CCF of the pumps failing to run is modeled. For the configuration where both high-head pumps are in standby, CCF of failure to start and CCF of failing to run are modeled.) These operational differences only resulted in negligible differences in HPI system unreliability.

As shown in Figure 5, two plants accounted for the variability in this design class. These two plants (in decreasing HPI unreliability) are Haddam Neck and Millstone 3. The cold leg injection path of the high-head system at Haddam Neck is atypical of the high-head systems belonging to Design Class 6. Haddam Neck has one cold leg injection path (Cold Leg # 2) compared to the four cold leg injection paths for the other Design Class 6 plants. An additional factor affecting the HPI unreliability at Haddam Neck is the conservative success criterion for the intermediate-head system (for example, one-of-two pumps to three-of-three unfaulted loops) when compared to remaining Design Class 6 plants (typically one-of-four trains to two-of-four cold legs).

Although Millstone 3 is not atypical in redundancy levels for either the high-head or intermediate-head injection paths, the criterion for HPI success is more conservative than other plants in Design Class 6 (one-of-four pumps to three-of-three unfaulted loops compared to one-of-four pumps to two-of-four loops).

3.3 Comparison with PRA/IPEs

The fault tree models for the six design classes shown in Figure 4 provided the logic template for generating 72 plant-specific HPI unreliability models. The plant-specific models were quantified based on success criteria stated in the PRA/IPEs. The spare pump requiring manual operator action was not included in the quantification. In order to allow a fair comparison, the mission time of one half-hour was used. The logic model also provided the template for mapping relevant PRA/IPE component failure probabilities into an HPI system model. The mapping provides a relational structure for comparing PRA/IPE results to the estimates derived from the 1987–1997 experience.

To provide consistency in comparisons of PRA/IPE results to corresponding results of analysis of the 1987–1997 experience, the contributions to the HPI unreliability from support systems outside the HPI boundary defined in Section 2.1.3 were excluded from this study. (Section 3.5 provides a discussion of the support system failures that lie outside the HPI system boundary on HPI unreliability.)

Recovery events were included in the unreliability analysis where such actions were found in the 1987–1997 experience. The recovery failure modes identified in the 1987–1997 experience are those events for which actual diagnosis and repair of the HPI system are not required to make the system operational. PRA/IPEs may model this type of event at the system level. Due to the summary nature of the information provided in many of the PRA/IPEs (e.g: the lack of information related to model/quantification assumptions) and the small contribution of this type of recovery on the final estimate (i.e., failure to recover from an automatic actuation failure), these actions are not explicitly accounted for in the PRA/IPE data-based results calculated for this study. Other types of recovery modeled in PRA/IPEs involve actual diagnosis and repair of the components that experience a catastrophic failure. These types of recovery are generally modeled at the accident scenario level (i.e., accident sequence cut set) since actual diagnosis and repair of the failed equipment is required.

For comparison with PRA/IPEs, the failure probability estimates associated with the FTR mode of HPI operation were calculated on an hourly basis. An hourly failure rate was used to quantify the probability of failure to run. For these calculations, the run times stated in the LERs (or estimated from the LER information) for the unplanned demands (SI actuations) were used to estimate the hourly failure rate. The run times were generally short and no failures to run were observed. Because the FTR probability would be unrealistically (inconsistent with the failure data) high, the comparison of HPI unreliability based on the 1987–1997 experience and PRA/IPE failure rates uses a half-hour mission.

Long run times that are typically postulated in PRA/IPEs were infrequently observed in the 1987–1997 experience. The majority of the run times associated with the unplanned demands tended to be of much shorter duration. There was one instance of run times to approximately 6 hours. However, there were no failures associated with this event. The majority of the run times were about 15 minutes. Further, many of the run times were unspecified in the LERs. Due to the limited run time data, no time-dependent analysis of the failure rates could be performed. Therefore, the failure probability based on an FTR rate derived from short run times does not accurately reflect the longer mission time (24 hours) performance. Due to these concerns, the reader is cautioned in using the hourly rate without regard to the limited data used in the estimation.

The cumulative run time (actual plus extrapolated) based on the 188 unplanned demands where the pump train operated is approximately 202 hours. Table D-1 in Section D-1 of Appendix D provides a summary of the run time estimation.

3.3.1 HPI System Model Assumptions for Comparison with PRA/IPE Results

For the purposes of comparing the 1987–1997 experience and PRA/IPE data on a similar basis, the following conditions were assumed:

- A demand (SI actuation) for HPI flow is received by the HPI system.

- For comparison to the 1987–1997 experience, the FTR contribution to the unreliability assumes a half-hour mission time.

- Most IPEs do not provide data and adequate information to model the HPI actuation failure probability with a high degree of confidence. Therefore, the IPE-based calculations assume the actuation failure is implicitly included in the other failure modes (e.g: FTS). This assumption has no impact on the Design Class 1 through 5 results and only a minimal impact on the Design Class 6 results since the contribution of this failure mode, based on the 1987–1997 operating experience, is relatively low.

- The HPI system success criterion are based on those reported in the PRA/IPEs except where the success criterion uses a non-safety pump train or a spare pump that does not automatically start on a SI actuation. In these cases, the success criterion was modified to eliminate the non-safety pump train or spare pump. The success criterion depicted in the logic models is presented in Table 1.

- Only the injection phase of HPI operation is modeled. The long-term phase involving recirculation mode of HPI is not modeled.

Besides the overall HPI system unreliability comparisons, the component failure probabilities from the PRA/IPEs were grouped into the same system failure modes and pipe segments defined for analysis of the 1987–1997 experience. The component failure modes identified in the PRA/IPEs were grouped according to the following breakdown:

<u>Suction path segment (SUCT)</u>

FTO—Failure of the suction path valves and associated piping from the reactor water storage tank to deliver the flow to the pump trains necessary for HPI success. Also included in this segment are failures of the VCT that lead to HPI failure.

<u>HPI train actuation (ACT-CHANL)</u>

FTO—Failure to operate of the SI actuation channel for the HPI system.

<u>Pump train segment (HHSI or IHSI)</u>

MOOS—Unavailability of the HPI pump train due to maintenance.

FTS—HPI pump train failure to start and valve failures in the pump train suction and discharge piping.

FTR—HPI pump train failure to run and continue to run and valve failures in the pump train suction and discharge piping after successful start.

<u>Injection header segment (INJ-HDR)</u>

FTO—Failure of the HPI injection header/flow control valves and associated valves and piping to deliver the flow necessary for HPI success.

<u>Cold leg injection path segment (LOOP-INJ)</u>

FTO—Failure of the cold leg injection path/check valves and associated valves and piping to deliver the flow necessary for HPI success.

While there are additional component failure modes in a given PRA/IPE for the HPI system, they are generally for passive components and are insignificant with respect to the failure probability of the active components identified above. The effect of not including these additional components in the system failure probability estimate is small.

The failure mode probability estimates based on 1987–1997 experience that were used in the PRA/IPE comparison calculations are listed in Table 4. No between-plant variability was identified due to the sparseness of the data.

3.3.2 Comparison with PRA/IPE Results

Figure 6 shows the model results using the PRA/IPE data along with the model results using the 1987–1997 experience. The mission time postulated for HPI in PRA/IPEs ranged from a half-hour to

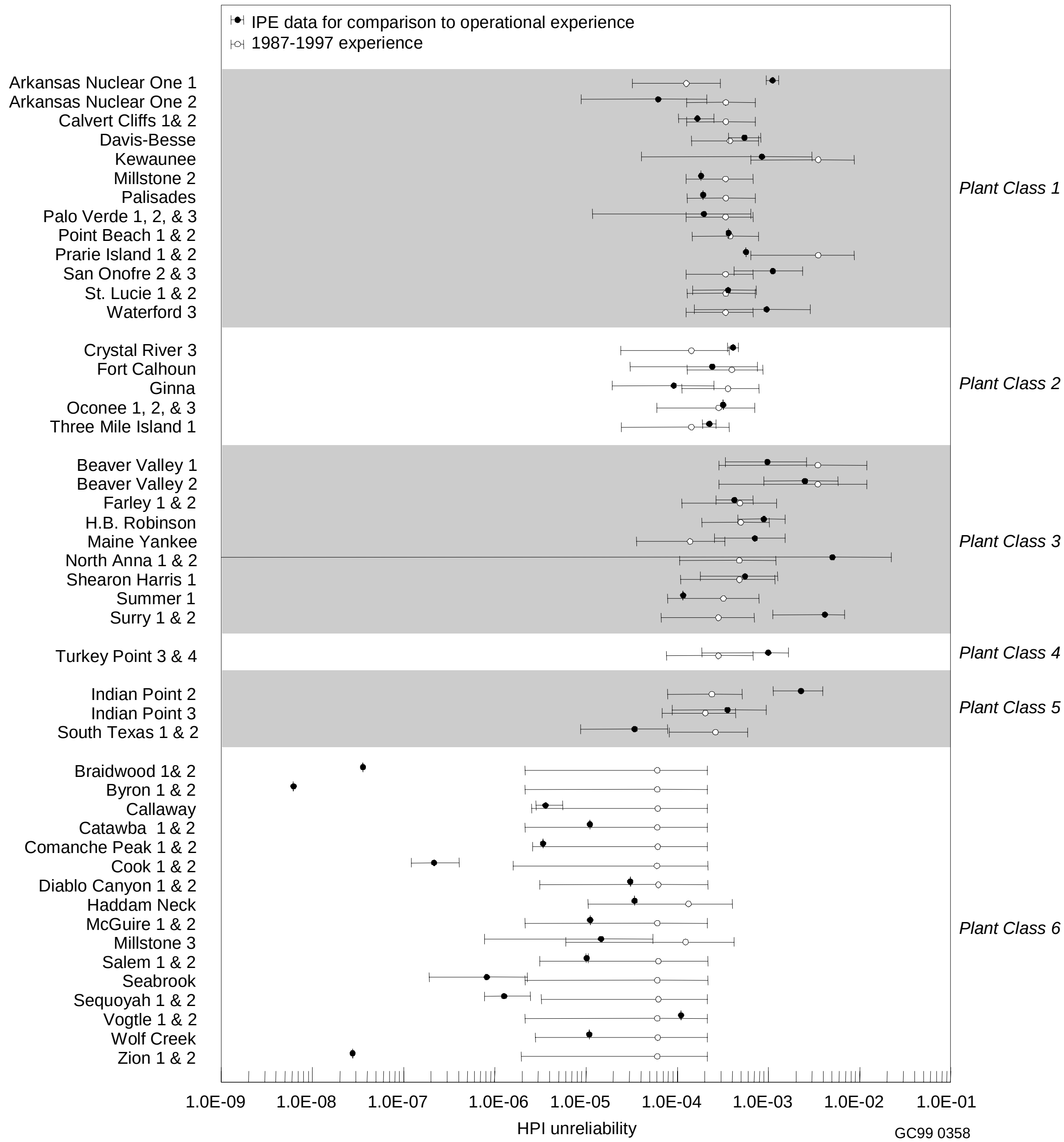


Figure 6. Plot of the PRA/IPE estimates of HPI unreliability (injection phase only). The mean and uncertainty values associated with this plot are listed in Tables D-3 and D-4 in Appendix D.

24 hours. About half of the PRA/IPEs used a 24-hour mission time. [Generally, the specified time of HPI operation reported in the PRA/IPEs includes both the injection (short-term) and recirculation (long-term) phases.] Model results provided in Figure 6 are based on a half-hour mission time. The rationale of using the half-hour mission time and the potential impact of using this mission time on the results is as follows. The cumulative run time is based on a total of 202 estimated run hours (See Appendix D, page D-1 for details of calculations) during approximately 400 run demands. That is, during the actual operating events, the average run time associated with the HPI pumps was approximately 0.5 hour. Using Bayes method, zero failures in 202 run hours results in a failure rate of 2.5E-03 per hour. Using zero failures and this relatively small amount of run-time most likely produces a conservative estimate of the hourly failure rate. Multiplying this conservative failure rate times a long 24-hour mission further amplifies the conservative nature of the failure to run probability. Therefore, in order to generate results that are both applicable and realistic with respect to the operating experience, a half-hour run-time mission was used. This half-hour run-time mission was also used for the HPI system reliability calculations using the PRA/IPE data to provide a consistent basis for comparison between the two estimates.

For nearly 50% of the HPI Design Class 6 plants, the unreliabilities derived from IPE data is within a factor of 2 of the unreliabilities generated using 1987–1997 experience. Considering that (a) the RWST suction path dominates the unreliability of this class, and (b) the Bayes estimate and Jeffreys noninformative prior with zero failures and 9504 demands were used to estimate the probability of the RWST suction path using operating experience, a factor of two difference indicates reasonable agreement between the unreliabilities based on the 1987–1997 experience and the IPE data. For the remaining 50% of the Design Class 6 plants, the unreliabilities based on the IPE data are one or more orders of magnitudes lower than the unreliabilities calculated using operating experience. This difference is attributed to the low failure probabilities assigned to passive components such as RWST in these IPEs.

For several plants in Design Classes 1 through 5 there were no overlaps between the plant-specific uncertainty bands calculated using IPE data and 1987–1997 experience. Due to the non-overlapping uncertainty bands, the difference between the two estimates is considered to be statistically significant. These plants are Arkansas Nuclear One 1, Surry 1 and 2, Indian Point 2, and South Texas 1 and 2. For Arkansas Nuclear One 1, the significant difference was due to the relatively high motor-operated valve CCF probability used in the IPE data based estimate. For Surry 1and 2, this significant difference was attributed to the relatively high failure probability used in the IPE for check valve failure. The CCF pump failure probabilities caused significant differences between the IPE data based and 1987–1997 experience based unreliabilities for South Texas 1 and 2 and Indian Point 2.

The HPI system unreliabilities (i.e., means) estimated using the PRA/IPE failure probabilities range from 6.2E-09 to 5.0E-03. The estimates of HPI unreliability based on the 1987–1997 experience range from 6.0E-05 to 3.5E-03. Table 7 lists the arithmetic average and range of values based on the 1987–1997 experience and the corresponding PRA/IPE values.

Table 8 provides a comparison of the independent failures and common cause failures contribution to the HPI unreliabilities based on the 1987–1997 experience and on the PRA/IPE data. Since the 1987–1997 experience has so few failures based on the unplanned SI actuation demands, caution is advised when making comparisons. Table D-2 of Appendix D provides a summary comparison of the cutset contribution to HPI unreliability based on the PRA/IPE failure probabilities and the failure probabilities estimated from the 1987–1997 experience for the six reference plants. The corresponding cutset listings are provided in Tables D-5 and D-6.

Table 7. Average design class unreliability (injection phase only) calculated from the 1987–1997 experience compared to the values calculated from the PRA/IPEs.

HPI Design Class	Number of Plants	IPE Comparison	1987–1997 Experience
1 — (2 HHSI or 2 IHSI; 2 SGs)	20	4.8E-04	8.1E-04
2 — (3 HHSI or 3 IHSI; 2 SGs)	7	2.7E-04	2.7E-04
3 — (2 HHSI or 2 IHSI; 3 SGs)	12	2.1E-03	9.1E-04
4 — (4 IHSI; 3 SGs)	2	9.9E-04	2.8E-04
5 — (3 IHSI; 4 SGs)	4	6.7E-04	2.4E-04
6 — (2 HHSI, 2 IHSI; 4 SGs)	27	1.6E-05	6.6E-05
Overall average[a]		5.8E-04	4.5E-04
Range of estimates for all 72 plants		6.2E-09–5.0E-03	6.0E-05–3.5E-03

a. The values are arithmetic averages.

Table 8. Comparison of the independent failure and common cause failure contribution (for the reference plant in each design class) to the risk-based unreliability (injection phase only) based on IPE data and 1987–1997 experience.

	Reference Plant PRA-based Unreliability		Contribution (%) To Unreliability: Multiple Independent Failures		Contribution (%) To Unreliability: Common Cause Failure	
HPI Design Class	1987–1997	IPE	1987–1997	IPE	1987–1997	IPE
1—(2 HHSI or 2 IHSI; 2 SGs)	3.4E-04	9.5E-04	27	9	73	90
2—(3 HHSI or 3 IHSI; 2 SGs)	2.9E-04	3.2E-04	28	15	72	85
3—(2 HHSI or 2 IHSI; 3 SGs)	4.8E-04	5.5E-04	18	59	82	41
4—(4 IHSI; 3 SGs)	2.8E-04	9.9E-04	5	7	95	71
5—(3 IHSI; 4 SGs)	2.6E-04	3.4E-05	20	<1	80	>99
6—(2 HHSI, 2 IHSI; 4 SGs)	6.1E-05	3.6E-08	99	72	—[a]	—[a]

a. No CCFs were identified across the high-head and intermediate-head systems. Only CCFs modeled are within a system.

3.3.3 Maintenance-Out-of-Service—Pump Train Segment

Table 9 is a summary of the maintenance-out-of-service estimates found in the PRA/IPEs and the estimates calculated from the 1987–1997 experience. In this study, maintenance unavailability is estimated using the failures and demands when the HPI system was required to supply water into the cold leg (i.e., a reliability parameter). Risk analysis generally accounts for the maintenance-out-of-service probability as an unavailability estimate (i.e., fraction of HPI down time compared to total plant operating time). In theory (i.e., infinitely large sample), these two estimates should be equivalent. Due to these different calculation methods used for computing maintenance unavailability, the reader is cautioned when making absolute comparisons of the PRA/IPE and the 1987–1997 experience probability estimates of maintenance-out-of-service.

Table 9. Pump train segment maintenance-out-of-service probabilities (per demand) calculated from IPE data and 1987–1997 experience.

	IPE Data		1987–1997 Experience	
Maintenance-Out-of-Service	Average	Range	Mean	90% Uncertainty Interval
High head	2.5E-02	1.3E-04 — 3.3E-01	5.2E-03	2.0E-05 — 2.0E-2
Intermediate head	6.3E-03	3.9E-05 — 5.0E-02	3.1E-03	1.2E-05 — 1.2E-02
Combined[a]	1.5E-02	3.9E-05 — 3.3E-01	1.9E-03	7.7E-06 — 7.5E-03

a. The "Combined" value for the IPE Data is an arithmetic average of the high-head and intermediate-head values stated in the PRA/IPE.

For high-head MOOS, the average of the PRA/IPE estimates is about a factor of five greater than the mean estimate of the 1987–1997 experience. Both the PRA/IPE estimates and 1987–1997 experience estimates for intermediate-head MOOS compare well, about a factor of two. The average of the PRA/IPE intermediate- and high-head MOOS estimates ("Combined") is about a factor of ten greater than the mean probability calculated from the 1987–1997 experience.

3.3.4 Failure to Start—Pump Train Segment

Table 10 provides a summary of the pump train segments failure to start probabilities of the HPI pumps found in the PRA/IPEs and the estimates calculated from the 1987–1997 experience. For high-head FTS, the average of the PRA/IPE estimates is in good agreement with the mean estimate of the 1987–1997 experience. The average of the PRA/IPE estimates of the intermediate- and high-head FTS ("Combined") is about the same as the mean probability calculated from the 1987–1997 experience.

3.3.5 Failure to Run—Pump Train Segment

Table 11 is a summary of the failure to run estimates found in the PRA/IPEs and those calculated from the 1987–1997 experience using the unplanned demands. Since the run times associated with the successful missions were relatively short and there were no observed failures, the estimate based on the 1987–1997 experience only applies to missions that are relatively short (e.g: one-half hour). Use of this rate on a typical mission stated in the PRA/IPEs would produce unreasonable probabilities (i.e., the value is too large and therefore is not consistent with no failures being observed).

3.4 Human Error of Commission

There was one event identified where the entire HPI system was made unavailable for automatic initiation by actions of the control room operators when an SI signal was present. This event occurred when an operator bypassed the HPI system from actuation during a reactor coolant system (RCS) depressurization transient. The bypassing of HPI was inappropriate since he did not receive permission to bypass HPI and the acknowledgement of the bypass by the Senior Reactor Operator (SRO) was not provided. However, the operator had announced his intention to bypass HPI and operator interviews indicated that the SRO on duty was aware of the bypass. Furthermore, prior to bypassing HPI, the operators used trouble-shooting strategies during the steady slow decrease of RCS pressure (the pressure decreasing over 19 minutes) looking for symptoms of a LOCA and pressurizer heater failures. The Operations Superintendent noticed the bypass and was discussing with the SRO the action to remove the bypass when the low RCS pressure bistables tripped. At this time the SRO ordered the bypass to be

Table 10. Pump train segment failure to start probabilities (per demand) calculated for comparisons with PRA/IPE results and 1987–1997 experience.

	IPE Data		1987–1997 Experience	
Failure to Start	Average	Range	Mean	90% Uncertainty Interval
High head	2.1E-03	2.1E-04—5.0E-03	3.4E-03	1.4E-05—1.3E-02
Intermediate head	2.4E-03	2.8E-04—9.7E-03	6.5E-03	7.7E-04—1.7E-02
Combined	2.3E-03[a]	2.1E-04—9.7E-03[a]	3.0E-03	3.2E-04—7.9E-03

a. The “Combined” value for the IPE Data is an arithmetic average of the high-head and intermediate-head values stated in the PRA/IPE.

Table 11. Pump train segment failure to run probabilities calculated from IPE data and 1987–1997 experience.

	IPE Data		1987–1997 Experience	
Failure to Run	Average	Range	Mean	90% Uncertainty Interval
High head	7.7E-05/hr	7.6E-06—5.4E-04	—	—
Intermediate head	5.8E-04/hr	5.3E-06—9.3E-03	—	—
Combined	3.6E-04/hr[a]	5.3E-06—9.3E-04[a]	2.5E-03/hr	9.9E-06—9.5E-03

a. The “Combined” value for the IPE Data is an arithmetic average of the high-head and intermediate-head values stated in the PRA/IPE.

removed, at which time the HPI successfully responded. After HPI provided full flow for one minute, the system was once again placed in bypass per the procedure, so that equipment could be manually controlled. Although this event is significant from a procedure compliance perspective (i.e., operator securing a safety system while a valid HPI actuation signal existed), it was excluded from the unreliability analysis.

This particular EOC was omitted from the HPI unreliability calculations since (a) the error could not have occurred during a small LOCA or a steam generator tube rupture (SGTR) and the system unreliability is calculated for mitigating these events, and (b) the system was placed in bypass after a minute of injection and as a result, the operator error is more likely classified as a “procedure non-compliance” rather than a system failure.

3.5 Sensitivity of Support System Failures (Outside HPI System Boundary) on HPI Unreliability

Based on the 1987–1997 unplanned demand data, two LER events involving two failures were attributed to support system failures that are outside the HPI system boundary defined for this report. None of these support system failures disabled the entire HPI system. The failures were all related to a single failure of the HPI train failing to operate. In the first event, an inadvertent SI actuation occurred while testing an emergency-diesel generator for operability. The operability test is performed by simulating a loss of ESF Bus voltage concurrent with an SI actuation test signal. The ESF bus was de-energized and a manual SI to the diesel generator was initiated. However, concurrent with the manual SI, an inadvertent SI was generated on both HPI trains when the bus was de-energized. The diesel-generator output breaker failed to close resulting in an HPI train unable to respond to a SI signal. The failure occurred while the plant was shutdown and undergoing refueling. The second event occurred during a loss of offsite power while one of the emergency-diesel generators was inoperable. The plant was at full power at the time of the event. During this event, only one of the redundant HPI trains responded to the SI actuation. The effects of including these support system failures on the train level failure mode (FTO-ACT-CHANL) estimates are negligible due to the redundancy of the SI actuation channels.

4. ENGINEERING ANALYSIS OF THE 1987–1997 EXPERIENCE

This section documents the results of an engineering evaluation of the 1987–1997 operational experience of the HPI system obtained from LER data. Failures occurring during unplanned demands are sparse. Therefore, segment failures that occurred during unplanned demands, surveillance tests and other routine plant operations were used to develop trends of failure frequencies. The following paragraphs summarize the major findings in this section of the report.

- Trends were identified in the frequency of the HPI unplanned demands, which includes both actual SI and inadvertent SI actuations. When modeled as a function of both calendar year and low-power license dates (plant age), the unplanned demand frequency exhibited a statistically significant decreasing trend.

- The frequency of failure events observed during unplanned demands and other detection methods such as testing were analyzed to determine trends. When modeled as a function of both calendar year and low-power license dates, both factors were statistically significant. Statistically significant decreasing trends were also identified in the frequency of inadvertent and spurious SI actuations when modeled against calendar year but not against low-power license dates. No other trend analysis indicated a statistically significant trend.

- Common cause failure was a leading contributor to HPI unreliability as indicated previously in Section 3. Twenty-one CCF events (approximately 17% of the 125 failure events) were identified in the 1987–1997 operating experience that either resulted in multiple failures or exhibited the potential to fail multiple segments. The dominant contributors to CCF were:

    - Failures in HPI mini-flow lines,

    - Hardware failures attributed to procedural or design flaws affecting redundant trains,

    - Gas binding,

    - Failed MOVs affecting the functionality of injection headers or suction path, and

    - Level indication in suction tanks.

Table C-2 of Appendix provides additional details on the CCF events identified during 1987-1997 period from the LERs.

- The leading HPI segments involving CCF events were the intermediate-head pump (7 CCF events involving 14 failures) and the high-head pump (7 CCF events involving 12 failures). The injection header segment had 4 CCF events involving 18 failures, while the RWST suction segment had 3 CCF events with 4 failures.

Sections 4.1 through 4.3 provide a detailed summary of the industry data supporting the above results. Additional insights were derived from (1) an assessment of the operational data for trends and patterns in system performance across the industry and an evaluation of the relationship with low-power license date, and (2) identification of the factors affecting segment reliability in the industry.

4.1 Industry Trends

This section provides the results of industry trend analyses. The analyses include HPI unplanned demands (SI actuations) and segment failures plotted against calendar year and low-power license date. The frequencies of unplanned demands or failures provided in the figures are the number of events (unplanned demands or failures) that occurred in the specific year divided by the total number of reactor-critical years or reactor-calendar years, as appropriate, for the specific year. Reactor-calendar years were estimated as described in Section A-2.2.4 of Appendix A. The estimated frequencies and 90% confidence intervals are plotted in each figure in this section. A fitted trend line and 90% confidence band on the trend line are also shown in the figures.

Two subsets of SI actuations are also of interest:

- Automatic and manual actuations (actual unplanned demands). Nearly all of these occur during reactor criticality, so the frequency is calculated as events per *reactor-critical* year. The trend in automatic and manual actuations is of interest since these events are indicative of situations where the RCS deviated from the normal conditions.

- Inadvertent and spurious actuations. These occur during both criticality and shutdown, so the frequency is calculated as events per *reactor-calendar* year. The trend in inadvertent and spurious actuations is of interest since these events are indicative of human errors or malfunctions that would initiate SI.

4.1.1 Summary of Data

Table 12 provides the HPI segment failures and unplanned demands that occurred in the industry for each year of the study period. Table 12 is a complete list of failures in the database. (There were no failures classified as maintenance-out-of-service events and only several support system failures were identified. The inclusion of the support system failures does not affect the inferences made.)

Table 12. Number of HPI events by category for each year[a] of the study.

Category	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Total
SI Actuations	38	36	39	26	23	18	10	10	10	5	9	224
Automatic /Manual	15	16	20	3	11	6	4	2	2	2	4	85
Inadvertent/Spurious	23	20	19	23	12	12	6	8	8	3	5	139
Failure Events	13	17	13	15	13	17	2	14	4	11	6	125
Number of Failures	22	22	17	30	18	26	3	21	4	14	7	184
Reactor-calendar years[b]	64.3	67.2	69.5	70.9	71.0	71.2	71.9	72.0	72.0	72.2	70.0	772.3
Reactor-critical years[b]	45.5	50.7	50.5	52.5	56.1	57.1	56.1	59.2	59.2	58.1	52.0	596.9

a. Each entry consists of the number of events that occurred in that calendar year.

b. Plant operating years and critical years are computed from low-power license date.

The next subsection, Section 4.1.2, gives the results of analyzing the SI actuations for trend by calendar year and by low-power license date. Section 4.1.3 gives similar results for HPI failure events.

4.1.2 Trends in SI Actuations (Unplanned Demands)

Figure 7 shows the frequency of SI actuations (unplanned demands for the HPI system) as a function of calendar year. The dots and vertical lines are point estimates and 90% confidence intervals for the frequency, each calculated using data for only one year. The estimated frequency is the number of events (ESF actuations resulting in HPI demands) that occurred in the specific year divided by the total number of plant operational years for the specific year. The fitted frequency, assuming an exponential trend, and a 90% confidence band for the frequency are also shown. This figure ignores the possible effect of low-power license date.

As shown in Figure 7, based on the fitted rate, the frequency of unplanned HPI demands for a population of 72 PWRs decreased from approximately 48 in 1987 to approximately 6 in 1997. The trend is highly statistically significant. The statistical significance of the trend (p-value = 0.0001) is calculated based on the full model that considers both calendar year and low-power license date

To give some indication of the effect of plant aging (that is, older plants versus newer plants) on HPI demands, a trend of plant-specific unplanned demand frequency was plotted against the low-power license date. Figure 8 shows the frequency of all SI actuations as a function of the low-power license date. The plot ignores the effect of calendar year. However, the statistical significance of the trend in low-power license date (p-value = 0.01) was based on the full model that accounts for both calendar year and low-power license date.

Since the p-value is less than 0.05, Figure 8 shows a statistically significant increasing trend. This means that the frequency of unplanned demands for HPI of plants that were licensed recently, on the average, is expected to be higher than that of older plants. However, the absolute difference in the frequency was small. Based on the fitted rate shown in Figure 8, a plant that received a low-power license in 1967 can be expected to experience an unplanned HPI demand about once every 4 years. In comparison, a plant that received a low-power license in 1993 can be expected to experience an unplanned HPI demand once every 2½ years. Furthermore, the significance of this difference is limited since the frequency of total unplanned demands from all plants has been trending down yearly.

In Figure 7, the SI actuation frequency is shown to be decreasing with calendar year, when the plant data are pooled within each year. Figure 8 shows that the same frequency depends on plant age, when the data from 1987 to 1997 are pooled within each plant. Both trends are plausible: the calendar year reflects industry-wide culture and regulations, which have resulted in a decreasing rate of scrams, and the low-power license date reflects the experience and learning at the particular plant. To identify the truly significant effects, the two variables were analyzed in a single model. This is the full model, and is the one that was used to calculate p-values and decide that both trends were statistically significant. Technical details of the analysis method are given in Section A-4 of Appendix A and a summary plot is shown in Section D-4 of Appendix D.

The two variables can be event date and low-power license date, or they can be expressed as event date and age of the plant when the event occurred. The information in either pair of variables is equivalent, because age is event date minus low-power license date.

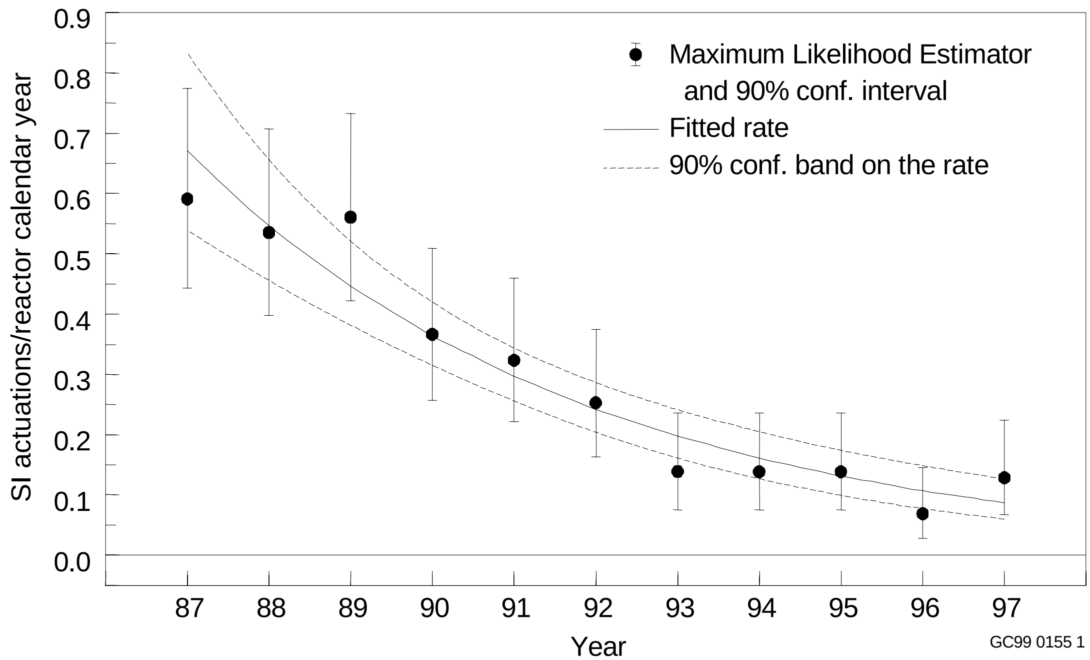


Figure 7. Frequency (events per reactor-calendar year) of all SI actuations, as a function of calendar year, with confidence limits on the individual frequencies. The calculations for this figure ignore the effect of low-power license date. The decreasing trend in year is highly significant (p-value = 0.0001).

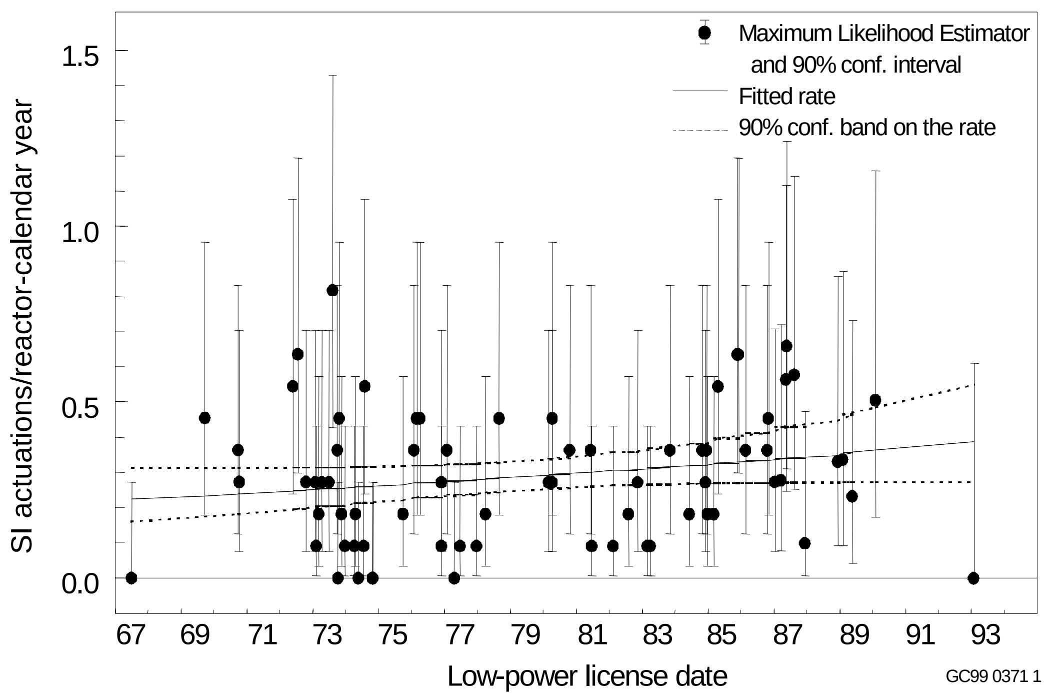


Figure 8. Frequency (events per reactor-calendar year) of all SI actuations, as a function of low-power license date. Each point corresponds to a single plant. The calculations for this figure ignore the effect of calendar year. The increasing trend in low-power license date is statistically significant (p-value = 0.01).

4.1.3 Trend in Failures

The following subsections contain the results of analyzing the HPI failure events for trend by calendar year and by low-power license date. Failure events associated with the HPI system that were reported in LERS were also trended. The frequency of failure events is expressed here as events per reactor-calendar year. Figure 9 plots the frequency of failure events associated with the HPI system as a function of calendar year. The dots and vertical lines are point estimates and 90% confidence intervals for the frequency, each calculated using data for only one year. The estimated frequency is the number of failure events that occurred in the specific year divided by the total number of plant operational years for the specific year. This is an industry average, not reflecting low-power license date or individual plant differences. The decreasing trend in year is statistically significant (p-value = 0.02). Based on the fitted rate shown in Figure 9, the frequency of reportable events of the HPI system for a population of 72 PWRs decreased from approximately 18 per year in 1987 to approximately 7 per year in 1997.

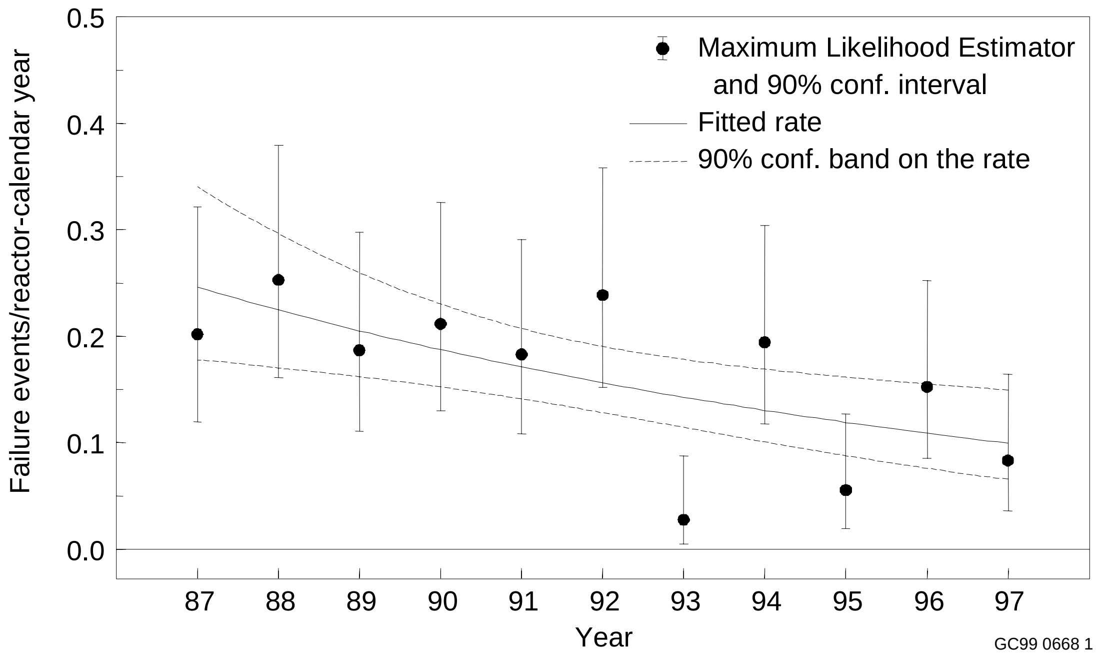


Figure 9. Frequency (events per reactor-calendar year) of all HPI failure events, as a function of calendar year. The calculations for this figure ignore the effect of low-power license date and plant-specific variation. The decreasing trend in year is statistically significant (p-value = 0.02).

Figure 10 shows the frequency of HPI failure events as a function of low-power license date. The trend is statistically significant (p-value = 0.026). This means that the frequency of reportable failure events in HPI systems of plants that were licensed recently, on the average, is expected to be lower than that of older plants.

Based on the fitted rate shown in Figure 10, a plant that received a low-power license in 1967 can be expected to report a failure affecting HPI about once every 4 years. In comparison, a plant that received a low-power license in 1993 can be expected to report a failure affecting HPI once every 10 years. The significance of this difference is limited since the frequency of reportable failures from all plants has been trending down yearly. Furthermore, an examination of the nature of the failures associated with older versus newer plants showed that the observed trend is not indicative of aging.

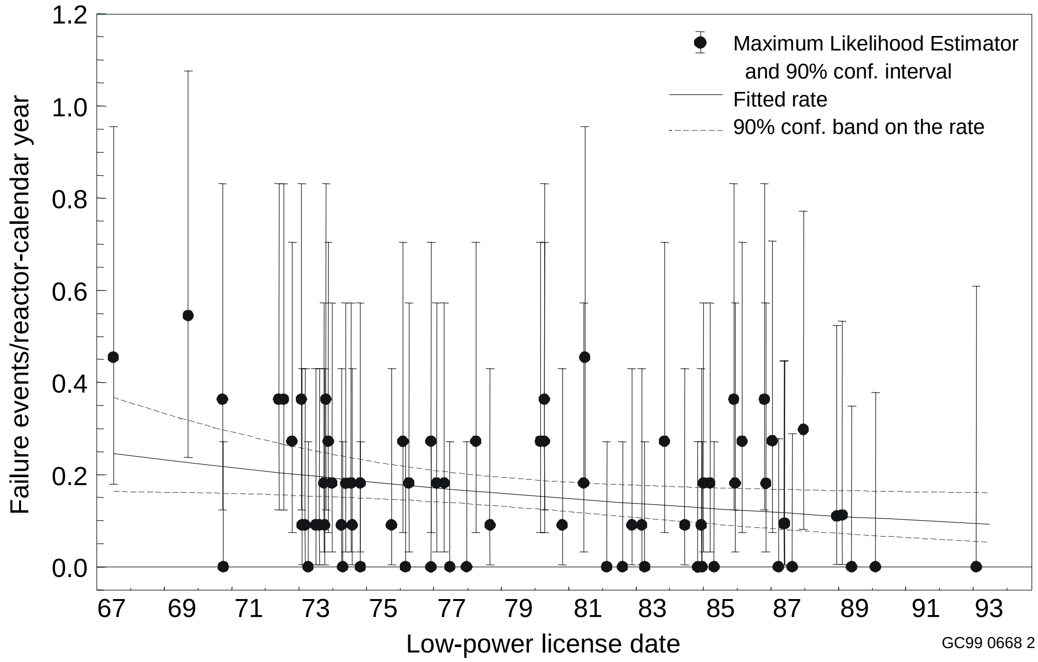


Figure 10. Frequency (events per reactor-calendar year) of all HPI failure events, as a function of low-power license date. Each point corresponds to a single plant. The calculations for this figure ignore the effect of calendar year. The decreasing trend in low-power license date is statistically significant (p-value = 0.026).

When failure frequency was modeled as a function of both calendar year and plant age, both factors were statistically significant. To accurately assess the goodness of fit, it was necessary to group calendar years and low-power license years into two-year bins. When this was done, the fit was poor (p-value for lack of fit = 0.0006). Between-plant variation appeared to be an important contributor to the lack of fit. Therefore, plant-specific effects were added to the model. To use the plant information, the low-power years were not collapsed. The calendar years were combined into two-year bins, however, to allow for accurate assessment of the goodness of fit. When this was done, the fit was good (p-value for lack of fit = 0.4). Both calendar year and low-power license date were statistically significant (p-values of 0.02 and 0.03, respectively). For more details, see Section A-4 of Appendix A and Section D-4 of Appendix D.

4.2 Factors Affecting HPI Reliability (Failures Identified During SI Actuations)

The HPI segment failures were reviewed to determine the factors affecting overall system reliability. This review primarily focuses on the causes and mechanisms of the segment failures that have a dominant impact on system unreliability. Section 4.2 discusses only those failures observed during the unplanned demand (SI actuation) and with CCFs that dominate the unreliability results. Segment failures found as a result of a surveillance test or from other methods are not presented in this section. Since CCFs are a dominant contributor to unreliability, those events are also discussed in Section 4.2. All HPI CCF events discussed here, except for those events that occurred since 1995, are included in the CCF database compiled by INEEL (Ref. 50) as well. The CCF events between 1987 and 1995 in the INEEL CCF database were used to calculate the CCF alpha factors used in this study. Section 4.3 provides a qualitative discussion of the failures found during surveillance testing or other detection methods.

4.2.1 System Reliability

The HPI system consists of multiple independent trains that increase the reliability of the system because a single component or train failure will not disable the system's safety function. There were no system failures during unplanned demands. However, failures of two or more HPI trains were observed in the other HPI failure events. Since CCFs are the dominant contributor to HPI unreliability, these events are described in this section.

Twenty-one CCF events (approximately 17% of the 125 failure events identified Table 12) were identified in the 1987–1997 operating experience that either resulted in multiple failures or exhibited the potential to fail multiple segments. The CCF events that were detected other than during an unplanned demand resulted in 48 HPI segment failures. The leading HPI segments involving CCF events were the intermediate-head pump (7 events involving 14 failures) and the high-head pump (7 CCF events involving 12 failures). The injection header segment had 4 CCF events involving 18 failures, while the RWST suction segment had 3 CCF events with 4 failures.

Hardware and personnel problems accounted for approximately one-half of the CCF events. Testing identified 30% of the CCF events associated with hardware and personnel. Overall, testing discovered about one-third of the CCF events identified in the 1987–1997 operating experience. Design/review and tour of the plant resulted in approximately one-third of the CCF events being identified. Table C-2 of Appendix C provides additional details of these CCF events.

4.2.1.1 CCFs of the Intermediate–head pumps. The seven common cause failure events associated with the intermediate-head pump segments were attributed to two hardware problems, two environmental problems, two procedure problems, and a personnel error. Six of these events were related to failure to run and one as a failure to start. The hardware problems were failures related to the intermediate-head pump mini-flow recirculation lines. In one event, the mini-flow recirculation lines were frozen due to the failure of a heat trace temperature switch. In the second hardware related event, a leak on a socket weld on the common pump recirculation line caused all intermediate-head pumps to be inoperable.

The environmental problems were the result of mini-flow recirculation line obstruction. In one event, both safety injection pumps failed to satisfy the minimum recirculation flow required for the periodic test. The apparent cause of the low recirculation flow in the pumps was a restriction in the pump recirculation line. The restriction was dislodged or eliminated from the recirculation line during the investigation. In the second environmental event, the restriction or obstruction was a result of a frozen section of the pump recirculation line piping. A portion of the piping line, just before the Refueling Water Storage Tank passes through the Purge Room inside the duct of the Inlet Plenum for the Purge Supply. With below freezing conditions in the outside environment, this area could see freezing temperatures. Corrective actions include rerouting the piping and installing a temporary heat trace with administrative controls to eliminate the conditions for a pipe freeze. A future modification was planned to reroute the pump mini-flow recirculation line.

The personnel-error-related CCF event was detected during testing. Following performance of an unscheduled surveillance test to demonstrate Safety Injection system operability, Safety Injection pump "B" was declared inoperable due to inadequate recirculation flow. Safety Injection pump "A" was also declared inoperable due to an observed declining trend in the pump's recirculation flow. Although the recirculation flow acceptance criteria was satisfied, after consultation with the licensee's Operations Manager, the pump was conservatively declared inoperable based on a greater than ten percent decline in flow rate from the last three tests. The cause of the Safety Injection pump "B" reduced recirculation flow is attributed to foreign material blockage within the associated mini-flow recirculation flow orifice.

Plastic sheeting was found in the pump discharge recirculation line. The blockage of the flow limiting orifice in the Safety Injection pump recirculation piping prevented the mini-flow recirculation flows needed to assure reliability of the pump during periods when the pump is not flowing water to the Reactor Coolant System. During periods of operation under minimum recirculation flow conditions, this recirculation flow provides the only source of cooling to the pump. This event was identified by the ASP Program[51] and was assigned a CCDP of 3.5E-05.

The procedure-related problems were due to the control power fuses being removed while the plant was in mode 4 and a potential CCF due to the improper gasket installation and assembly of two motor coolers for the intermediate-head pump.

4.2.1.2 CCFs of High–head pumps. The seven common cause failure events associated with the high-head pump segment were caused by two design-related events, two gas binding events, and one event each for procedure, maintenance, and hardware. Six of these events were classified as failure to run and one as failure to start. The design related problems were related to the alternate mini-flow (AMF) lines and inadequate ventilation of the cubicle containing the high-head pumps. These alternate mini-flow (AMF) lines are designed to protect the high-head pumps, which provide high head safety injection as well as normal charging, from deadhead operation during accidents where the Reactor Coolant System (RCS) repressurizes after safety injection is actuated. Damage to relief valves and drain connections on these AMF lines were such that a significant portion of the safety injection flow would have been diverted from the RCS. The system was repaired and procedures were revised to preclude recurrence. The AMF lines were modified to eliminate the use of relief valves. The modified system uses orifices and revised motor-operated valve logic to protect the high-head pumps from deadhead operation. This event was identified by the ASP Program and was assigned a CCDP of 6.3E-03.

The inadequate ventilation of the high-head pumps was determined during a design review. The actual measured ventilation flow from each high-head pump cubicle was found to be less than the flow-rate required by the calculations to maintain motor temperatures within required Environmental Qualification limits. An investigation determined that a manual isolation damper, common to all three high-head pumps, was failed in a partially closed position. The damper was repaired and placed in the proper position to meet flow requirements.

A gas binding problem associated with the high-head pumps occurred when an attempt was made to placing a charging pump in service and securing the operating pump. When the running pump was stopped, the operator observed fluctuations in pump flow and motor current on the operating pump. The pump was secured after returning the standby pump to service. After venting the pump casing and discharge piping, the pump was restarted. Similar fluctuations in pump flow and current were observed, and the pump was again stopped. The pump casing and discharge piping were again vented. The pump suction piping was also vented without complete success. The venting operations continued and a length of piping from the residual heat removal (RHR) heat exchanger discharge to the high-head pump suction header was vented. The pump was started and normal operating parameters were observed. The pump was subsequently tested. Vibration diagnostics, pump flow, and discharge pressure indicated acceptable pump performance. However, non-intrusive ultrasonic testing indicated that a small pocket of gas was present in the horizontal section of suction piping from the RHR discharge to the high-head pumps. An evaluation of the event concluded that hydrogen gas was coming out of solution and accumulating in certain pipe locations. It was subsequently determined that hydrogen gas had been coming out of solution on both units and accumulating in the suction piping as a probable result of gas stripping by the mini-flow orifices. In addition, entrainment of hydrogen bubbles from the volume control tank to the suction piping may be a contributor as well. In the original plant design, the mini-flow returned to the VCT rather than to the pump suction line. However, as a result of a Westinghouse generic letter concerning the potential for overfilling the VCT after swap-over from the VCT to the RWST, the mini-flow was rerouted to the high-head suction line downstream of the VCT outlet valves. This event was identified by the ASP Program and was assigned a CCDP of 6.0E-04.

The other gas-binding-related failure of the high-head pump, as the result of shaft cracking, was attributed to impact loading due to gas. In this event, an operational surveillance test showed that a charging pump could not meet the required performance criteria. The pump was declared inoperable and a spare pump was installed in its place. The pump shaft was cracked. The crack was believed to result from abnormal impact loading on the pump. The abnormal loading is attributed in part to gas voids in the suction during pump starts.

Nuclear Regulatory Commission (NRC) Information Notice 88-23, "Potential for Gas Binding of High-Pressure Safety Injection Pumps During A Loss of Coolant Accident,"[52] dated May 12, 1988, alerted licensees to potential problems resulting from hydrogen transport from the volume control tank and accumulation in emergency core cooling system piping.

The high-head CCF identified as maintenance related was detected when smoke was discovered coming from the speed increaser unit for a centrifugal charging pump (CCP). Upon disassembly of the CCP speed increaser, the internals were found damaged. Further investigation found the two gland seal (GS) retaining bolts inside the speed increaser lube oil pump (SILOP) backed out allowing the GS to loosen. The GS being loosened caused reduced oil flow to the speed increaser internals and ultimate damage. The SILOPs for the two other CCPs were inspected, and the same GS bolts as on the first pump were found loosened. The cause of the bolts backing out was determined to be lack of a periodic adjustment of the GS bolts. It was discovered during the investigation that the original SILOPs for three of the four high-head pumps had been replaced with incorrect SILOPs. Only one high-head pump did not have the original SILOP replaced with an incorrect SILOP. The replacement SILOPs had been ordered using an incorrect part number. The replacement SILOPs were rated for 900 rpm and incorporated a compression packing seal which requires periodic adjustment as the packing wears. The original SILOPs were rated for 1,800 rpm and incorporated a mechanical seal which does not require adjustment. The major cause of this event was that the replacement SILOPs were the wrong SILOPs that incorporated the packing seal, and no program was in place to periodically tighten the gland bolts. The SILOPs were replaced with 1800-rpm pumps. To prevent recurrence, a new procurement program that provides additional independent review/verification was instituted. This event was identified by the ASP Program and was assigned a CCDP of 3.8E-04.

The procedure related event occurred following an overhaul of High-Pressure Injection (HPI)/Make Up and Purification Pump P36A. System Engineering requested simultaneous operation of P36A and its auxiliary oil pump P64A for post-maintenance testing of repairs to the lube oil system control valve. During the test run, System Engineering observed that approximately one cup of oil per minute was flowing from the outboard pump bearing area. Further investigation revealed that a similar condition existed on pump P36C, although the oil loss was not as significant. An attached shaft-driven pump provides lubrication to the HPI pump bearings and gear drive. An electric-driven auxiliary lube oil pump provides lubrication during pump startup and shutdown. The auxiliary lube oil pump is operated for approximately one minute prior to starting the HPI pump. It is also started prior to stopping the HPI pump and allowed to continue running for at least one minute after the HPI pump is stopped. The auxiliary pump does not normally run while the HPI pump is running except during an Engineered Safeguards Actuation System (ESAS) actuation, during which the pump starts automatically and runs until manually secured. During an ESAS actuation, the low oil pressure trips of the HPI pumps are bypassed. The bypass allows the HPI pumps to start even if oil pressure has not built up and prevents the HPI pumps from tripping on low lube oil pressure during an ESAS actuation. Proper distribution of lube oil between the pump bearings and the high-speed gear drive is accomplished by adjustment of a hand control valve. Additionally, a pressure control valve that relieves back to the sump is installed to compensate for system overpressure conditions. It was concluded that this condition represented a common mode failure mechanism and that simultaneous operation of the HPI pump and the associated auxiliary lube oil pump for extended periods could result in excessive oil loss from the system and subsequent failure of the pumps. The root cause of the oil leakage from HPI pump bearings during simultaneous operation of the HPI pumps and their associated auxiliary oil pumps was lack of procedures for adjustment and verification of setpoints for either of the lube oil control valves. Not having had these procedures in place could have resulted in the control valves being improperly adjusted at any time since initial plant operation.

The high-head CCF event identified as hardware related resulted in both HPI pumps being damaged due to operation with an inadequate suction source. Both Letdown Storage Tank (LDST) level instruments erroneously indicated level was 55.9 inches for about one hour and forty-five minutes prior to the damage to the HPI pumps. However, at the time of the failure, the tank was essentially empty. Subsequent investigation determined the reference leg of the LDST level to be partially drained. The root cause is a combination of a design weakness of a common reference leg for the LDST level instruments and a leaking instrument fitting due to an inadequate work practice. This event was identified in the ASP Program and was assigned a CCDP of 5.4E-04.

4.2.1.3 CCFs of Injection headers. The four common cause failure events associated with the injection header segment were attributed to two hardware problems and two personnel error related problems. One of the personnel-related CCF events was the result of an operator closing two SI pump discharge header isolation valves. The second personnel CCF was due to flow rates being low in three legs of one HPSI loop and two legs of the other loop. The vendor for HPSI isolation valves made an error in fabrication drawings by incorrectly referencing an improper drawing for the valve disc plug.

The first hardware related CCF event was attributed to the relaxation of spring packs due to spring pack fatigue in 10 MOVs of the high-head and intermediate-head injection headers. The MOVs are equipped with a motor operator that is controlled by a torque switch that senses movement of a spring pack. The spring pack is used in conjunction with the torque switch to control the valve stem thrust. A drive worm screw provides compression to the spring pack, which in turn regulates the desired torque from the operator. Excessive relaxation of the spring pack could allow the torque switch to actuate at less than the desired value of stem thrust and result in premature cutout of the actuator motor.

The second hardware event was identified earlier in the section describing the thermal aging of the relays in the injection header MOVs. The hardware related CCF event was detected as part of a re-assessment of NRC Information Notice (IN) 92-27[53], "Thermally Induced Accelerated Aging and Failure of ITE/Gould AC Relays Used in Safety-Related Applications." It was identified that the failure mechanism described in the IN potentially exists for ITE/Gould J12 relays. The re-assessment was part of an evaluation to address six J12 relay failures that occurred (two in 1995 and four in 1996). The six J12 relays functioned as designed in response to an Engineered Safety Feature (SI) signal during testing. Inspection of J12 relays removed during a refueling outage identified that these relays had the potential to bind. Subsequent bench testing of a suspect J12 relay revealed that this relay will overheat, if mechanically bound, and potentially cause a short circuit. Such a short circuit could result in failure of the control power fuse for the component, rendering the component inoperable. Of the six bad relays, three were associated with the charging pump suction from the RWST, isolation of the VCT and the Boron Injection Tank isolation.

4.2.1.4 CCFs of RWST suction. The three common cause failure events associated with the RWST suction segment were attributed to a hardware problem, a design problem, and a personnel error. The design-related event occurred when level indication for the RWST was determined to be inoperable. The sensing lines had frozen due to subfreezing outdoor temperatures. Although the piping to the RWST level instrument lines was insulated and heat traced, the instrument root stop valve was not insulated and the electric heat trace wire on it was not wrapped around the valve. Additional heating was applied to thaw the affected lines and return them to service.

The second hardware event was identified in the previous section describing the thermal aging of the relays in the injection header MOVs. These relays were also found in the RWST suction segment as well.

The personnel error event was detected during a review. The event describes that the breakers for the High-Pressure Injection suction valves from the Borated Water Storage Tank were inadvertently left tagged open after the Reactor Coolant System had been heated up to greater than 350 degrees Fahrenheit.

4.2.2 Actuation Channel Reliability

In the unplanned demand operational data there was one event in which a SI actuation train of HPI failed to operate. In this event, the reactor was in the cold/refueling condition and an inadvertent safety injection occurred. Only the A train SI logic actuated and no containment ventilation isolation signal was received. All “A” train equipment not in pull stop operated as designed. Other SI equipment did not operate as it was either in pull stop for testing or was “B” train actuated. The underlying cause of the inadvertent SI was determined to be procedural inadequacy. The failure of the B train SI logic to actuate was due to mechanical interference between the plunger of a relay installed during the 1989 outage and a wire moved subsequent to the relay installation. This wire was moved for Engineering Work Request. The underlying cause of the failure of the “B” train SI logic to actuate due to the mechanical interference was because the installation and inspection requirements of the system modification overlooked the possibility of mechanical interference. The failure of the B train SI logic and the containment ventilation isolation to actuate was due to modifications performed during the outage. The scheduled post modification testing would have identified the above problems assuming the test is perfect. Labels were later installed on appropriate latching type relays to warn not to obstruct the operation of the relay plunger.

4.2.3 Intermediate-head Pump Reliability

While the plant was in a shutdown condition, an inadvertent SI actuation signal started all in-service equipment except one of the safety injection pumps which did not start as expected. This failure to start appears to be due to an intermittent failure mechanism that could not be duplicated during trouble shooting. A blocking and timing relay controlling the start of the SI pump were replaced. Subsequent testing during the integrated safeguards testing process resulted in repeated successful starts of the SI pump. The actuation occurred when a safety injection block relay failed to maintain the block signal after power application to the relay racks. The actuation cause was an intermittent seal-in contact failure of a block relay.

4.2.4 Injection Header/Cold Leg Injection Path

During an inadvertant SI actuation, a high-pressure safety injection valve did not fully open. The HPI loop injection valve did not open due to a blown fuse. The HPI loop injection valve was verified to operate properly after replacing the malfunctioning fuse. Troubleshooting revealed that there was no indication of a ground on the circuit and after installation of a new fuse, the HPI valve operated properly. The cause of the fuse opening could not be determined. Further testing was conducted and it was determined that the fuse failure was random and that the existing fuse specification is adequate.

4.3 Failure Causes and Detection Methods for all Failures in the HPI System

This review primarily focuses on the causes and detection methods of the segment failures by segment type observed during the unplanned demand (SI actuation), surveillance testing, and from other methods. Failures involving single components or trains of HPI systems are generally not reportable under 10CFR 50.73. Furthermore, many demands such as routine tests and operation of components are also not reportable. Therefore, it is not possible to use these data for estimating unreliabilities or determining dominant contributors to unreliability because they do not constitute an unbiased sample of performance. In previous studies, comparisons were made between the nature of events dominating the unreliability based on unplanned demands with the nature of failures detected by other mean such as surveillance testing, design reviews, etc. The small number of actual failures during unplanned demands between 1987–1997 precluded that assessment. Nevertheless, the following information relating the nature and causes of reported failures and detection is provided for information.

4.3.1 Failure Cause

The cause category that was assigned for each failure was based on the independent review of the data provided in the LER and does not correspond to the cause codes provided by SCSS. The cause categories were based on the data provided in the LERs and engineering judgment. The cause classification of each failure was based on the immediate cause of the failure and not a cause that may be determined through a root cause analysis of the failure that was provided by the plant. Specifically, the mechanism that actually resulted in the segment failing to function as designed was captured as the cause. This methodology precluded categorization of many of the failures as a “Management Deficiency” or simply a “Personnel Error,” which many of the LERs identified as the cause. For a detailed explanation of the definitions of each of the cause categories and examples of the types of failures assigned to each category, see Section A-2.1.1 of Appendix A.

Table 13 is a listing of the failures partitioned by segment type and the cause of the failure. Table 14 is a listing of the failures partitioned by the cause category and by calendar year. The review of the causes of the segment failures over the study period indicated that hardware-related failures contributed to approximately 40% of the failures. These failures were equally distributed throughout the study period with the exception of 1990, where the number of failures is about twice those of any other year. The failures attributed to personnel error, inadequate procedures, and design errors accounted for about 49% of the failures. The distribution of failures associated with these three cause categories over the study period did vary considerably. Specifically, the failures attributed to personnel-related problems had higher values (factors of at least two or three and comprising 65% of the failures) in years 1987, 1990, and 1992 than the remaining years. The distribution of procedural-related problems was relatively constant over the study period.

The reader is cautioned from making comparisons of the numbers provided in Tables 13 and 14 with the number of failures used in the unreliability analysis provided in the Section 3. The tables include the contribution of all failures identified in the LERs as well as support system failures (which were not used in the unreliability analysis). In addition, the common cause failures and the errors of commission are included with the tables as an independent count of failed segments. Specifically, if a common cause

Table 13. Failures partitioned by segment type and by cause category.[a]

Segment	Cause Category								
	Design	Envrnmnt[b]	Gas Binding	Hardware	Mainten[b]	Persnnl[b]	Procdre[b]	Supprt[b] Sys	Total
System	1	—	—	—	—	1	1	—	3
Train	—	—	—	5	—	—	—	2	7
RWST	2	—	—	2	—	2	1	—	7
Pump suction	—	—	—	—	—	4	—	—	4
High-head pump	5	—	4	17	2	12	7	6	53
Intermediate-head pump	2	6	—	22	—	14	5	—	49
Injection header	1	—	—	19	—	10	—	—	30
Cold leg injection path	2	—	—	9	—	10	10	—	31
Total	13	6	4	74	2	53	24	8	184

a. The reader is cautioned from making comparisons of the numbers provided in this table with the number of failures used in the unreliability analysis provided in Section 3. This table includes the contribution of all failures resulting from unplanned demands, surveillance tests, and other means of detection. In addition, common cause failures and errors of commission are included as individual failure counts.

b. Envrnmnt = Environment; Mainten = Maintenance; Persnnl = Personnel; Procdre = Procedure; Supprt Sys = Support System.

Table 14. Segment failures partitioned by cause category and by calendar year.

Cause	87	88	89	90	91	92	93	94	95	96	97	Total
Design	1	1	2	0	7	0	0	1	0	0	1	13
Environment	0	0	0	0	2	2	0	0	0	2	0	6
Gas Binding	0	0	0	2	0	0	0	1	0	0	1	4
Hardware	6	8	9	18	3	6	1	8	3	7	5	74
Maintenance	0	2	0	0	0	0	0	0	0	0	0	2
Personnel	13	4	5	7	2	14	0	6	1	1	0	53
Procedure	0	3	0	3	4	4	2	5	0	1	2	24
Support System	2	4	1	0	0	0	0	0	0	1	0	8
Total	22	22	17	30	18	26	3	21	4	12	9	184

failure resulted in two high-head pumps failing to start, the tables show two failures to start of high-head pumps, not one.

Table 15 is a listing of the intermediate- and high-head pump segment failures that were identified in the 1987–1997 experience partitioned by the cause category and failure mode. Only the high- and intermediate-head pump segments were partitioned by failure mode—the other segments failures were all classified as failure to operate. Therefore, as a result of the failure mode classifications, only the high- and intermediate-head pump segments required an additional data partitioning.

There were 53 failures of the high-head pump segment: 12 were classified as failures to start and 41 as failures to run. Hardware-related problems were the primary cause of high-head pump failures (32%), followed by personnel error (23%), procedure (13%), and support system (11%).

There were 49 failures of the high-head pump segment: 20 were classified as failures to start and 29 were classified as failures to run. The hardware and personnel category accounted for a majority of the failures, 45% and 29%, respectively.

There were 61 failures of injection header/cold leg injection path segments: 30 associated with the injection header segment and 31 failures of the cold leg injection path segment. Failures attributed to hardware problems accounted for about 46% of the failures, while personnel errors, procedure, and design errors accounted for approximately 33%, 16%, and 5% of the failures, respectively.

Table 15. Pump segment failures partitioned by cause category and failure mode.[a]

Segment	Design	Envrnmnt[b]	Gas Binding	Hardware	Mainten[b]	Persnnl[b]	Procdr[b]	Supprt[b] Sys	Total
	Cause Category								
High-head pump									
Failure to start	—	—	2	5	—	5	—	—	12
Failure to run	5	—	2	12	2	7	7	6	41
Intermediate-head pump									
Failure to start	2	—	—	8	—	8	2	—	20
Failure to run	—	6	—	14	—	6	3	—	29
Total[c]	2,5	0,6	2,2	13,26	0,2	13,13	2,10	0,6	32,70

a. The reader is cautioned from making comparisons of the numbers provided in this table with the number of failures used in the unreliability analysis provided in Section 3. This table includes the contribution all failures resulting from unplanned demands, surveillance tests, and other means of detection. In addition, common cause failures and errors of commission are included as individual failure counts.

b. Envrnmnt = Environment; Mainten = Maintenance; Persnnl = Personnel; Procdre = Procedure; Supprt Sys = Support System.

c. The first value is the number of failures to start; the second value is the number of failures to run.

4.3.2 Detection Method

This section of the report is comprised of summary information relating to the detection method and the failures identified in the 1987–1997 experience. The method of detection is the activity that revealed the existence of the failure. For example, the test category includes items such as leak rate tests, surveillance tests, post-maintenance tests, etc. The design/review category generally includes such items as review of logs, design or engineering evaluations, and subsequent investigations. The abnormal system parameter is typically assigned to abnormal indication of the operating system parameters other than by alarm methods. For a detailed explanation of the definitions of each of the detection method categories and examples of the types of failures assigned to each category, see Section A-2.1.1 of Appendix A.

Table 16 tabulates the failures identified in the 1987–1997 experience by method of detection and by cause category. The four major cause categories are identified explicitly while the other cause categories are grouped as “Remaining causes.” Based on the failure categorization used for this study, testing is the leading method for detecting failures. Overall, testing identified approximately 34% of the failures identified in the 1987–1997 experience compared to the next leading detection method, design/review, 21%. Approximately 12% of the failures were detected during an actual demand for HPI (4% of the failures during an actual SI demand and 8% during a demand for HPI other than the result of an SI actuation).

Based on the leading cause category (hardware) identified for this study, 30% of the hardware-related failures were detected by test followed by 18% for troubleshooting.

As noted earlier, the aggregated segment failures of the high-head, intermediate-head, injection header, and cold leg injection path comprised roughly 90% of the failures. Table 17 tabulates the failures by method of detection and by segment category. Figure 11 displays the information in Table 17 for the high-head, intermediate-head, and injection (injection header and cold leg injection path) segment failures by method of detection.

Table 16. Failures partitioned by detection method and by cause category.[a]

Detection Method	Design	Envrnmnt[b]	Gas Binding	Hardware	Mainten[b]	Persnnl[b]	Procdre[b]	Supprt[b] Sys	Total
	Cause Category								
Abnormal Sys. Param.	—	2	—	4	—	3	2	7	18
Alarm	2	—	—	7	—	2	—	—	11
Design/Review	2	—	1	9	—	21	6	—	39
non-SI Demand	1	—	2	9	—	3	—	—	15
SI Demand	1	—	—	4	—	1	—	1	7
Test	7	4	1	22	—	16	12	—	62
Tour	—	—	—	6	2	7	3	—	18
Troubleshooting	—	—	—	13	—	—	1	—	14
Total	13	6	4	74	2	53	24	8	184

a. The reader is cautioned from making comparisons of the numbers provided in this table with the number of failures used in the unreliability analysis provided in Section 3. This table includes the contribution of all failures resulting from unplanned demands, surveillance tests, and other means of detection. In addition, common cause failures and errors of commission are included as individual failure counts.

b. Envrnmnt = Environment; Mainten = Maintenance; Persnnl = Personnel; Procdre = Procedure; Supprt Sys = Support System.

Table 17. Failures partitioned by detection method and by segment category.[a]

Detection Method	System	Train	RWST	Pump suction	High- head	Intermediate-head	Injection[b]	Total
	Segment Category							
Abnormal Sys. Param.	1	1	—	—	12	2	2	18
Alarm	—	3	1	—	2	3	2	11
Design/Review	—	—	3	3	12	6	15	39
non-SI Demand	—	—	1	—	8	5	1	15
SI Demand	2	2	—	—	1	1	1	7
Test	—	—	2	1	11	24	24	62
Tour	—	—	—	—	6	8	4	18
Troubleshooting	—	1	—	—	1	—	12	14
Total	3	7	7	4	53	49	61	184

a. The reader is cautioned from making comparisons of the numbers provided in this table with the number of failures used in the unreliability analysis provided in Section 3. This table includes the contribution of all failures resulting from unplanned demands, surveillance tests, and other means of detection. In addition, common cause failures and errors of commission are included as individual failure counts.

b. The injection segment is the combined total of the SI-INJ-HDR, CC-INJ-HDR, and LOOP-INJ segment failures.

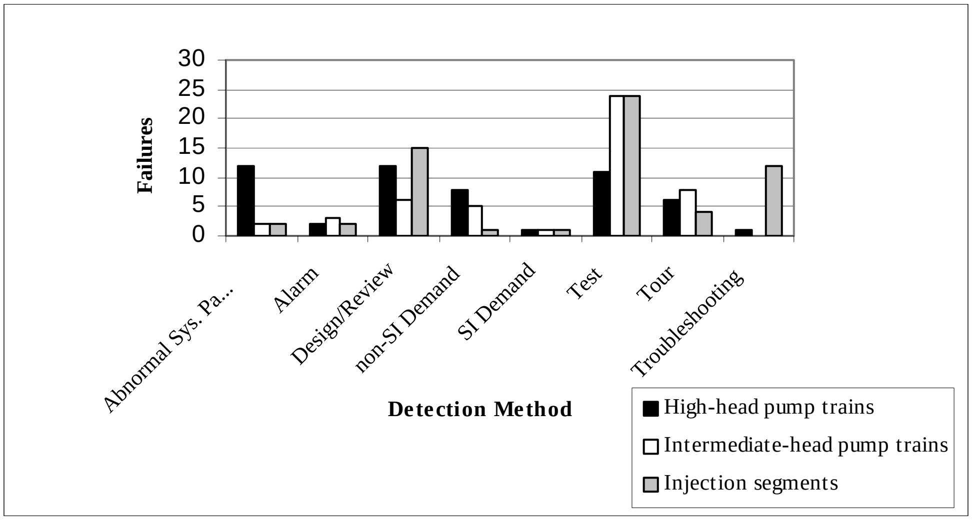


Figure 11. Distribution of the detection method by failures of the three major HPI segments.

4.4 Consistency Between ASP Events and Major Contributors to HPI Unreliability

Table 18 lists 15 ASP events involving failures or degradations in the HPI system between 1987–1997. These events were reviewed to determine their consistency with the dominant contributors to the HPI unreliability. The dominant contributor to HPI unreliability from the analysis of operating experience was CCF. The more significant ASP events (conditional core damage probability greater than 1.0E-04) were related to CCF of the HPI system. The ASP events of lesser significance (conditional core damage probability between 1.0E-04 and 1.0E-06) generally involved single train failures rather than CCF. This result is consistent with the results of the HPI unreliability analysis that indicated individual segment failures are not dominant contributors.

4.5 Regulatory Issues

Table 19 provides 14 Information Notices relating to HPI failures issues between 1987–1997. These Information Notices were reviewed to determine their consistency with the dominant contributors to HPI unreliability. The dominant contributor to HPI unreliability from the analysis of the 1987–1997 operating experience was CCF. A review of Information Notices issued between 1987–1997 relating to HPI failures showed that most of them (11 out of 14) related to CCF events or conditions. The other Information Notices addressed cracks in HPI pipe welds and a single HPI train failure.

Table 18. The listing of ASP events that identify a HPI failure.

Plant Name	LER	Event Date	Detect Method	Failure Mode	Cause	Description	CCDP
Cook 1	31595011	9/12/95	Test	FTR	Personnel	The pump operated at full flow for seven minutes before tripping. Overload relay tripped, improperly calibrated.	3.7E-05
Ginna	24490017	12/12/90	Abnormal Sys. Param.	FTO	Procedure	2 DC switches were opened disabling SI actuation.	2.0E-06
Haddam Neck	21395010	3/9/95	Design/Review	FTO	Design	Potential exists for pressure locking SI valves. No failure. None actually locked.	6.8E-06
Indian Point 2	24788020	12/11/88	Alarm	FTO	Design	RWST level detector lines frozen.	6.9E-06
Millstone 3	42391011	4/10/91	Test	FTO	Design	A safety injection system (SIH) relief valve lifted while performing a boundary valve leak test surveillance procedure. Did not reseat until the running “A” safety injection pump was stopped. Setpoint too close to operating pressure. Reset setpoint higher.	8.6E-04
Oconee2	27097001	4/21/97	Abnormal Sys. Param.	FTO	Hardware	Unisolable leak developed in the reactor coolant system high-pressure injection nozzle.	2.2E-05
Oconee 3	28797003	5/3/97	Alarm	FTR	Hardware	Two high-pressure injection pumps damaged because of low-water level in the letdown storage tank.	5.4E-06
Point Beach 2	30192003	9/18/92	Test	FTS	Personnel	During Containment Spray pump testing, low discharge pressure. Containment spray pump P-14A was disassembled and a foam rubber plug was found blocking the pump suction. Could have blocked SI pump. SI pumps later tested satisfactorily.	9.9E-06
Robinson	26192013	7/9/92	Test	FTR	Personnel	SI pump B recirculation line had foreign material blockage.	3.5E-05
Salem 2	31190042	12/20/90	Tour	FTR	Hardware	SW system leak disabled one SI pump while the EDG in maintenance made the other inoperable.	1.3E-06

Table 18. (continued).

Plant Name	LER	Event Date	Detect Method	Failure Mode	Cause	Description	CCDP
Salem 2	31190005	1/17/90	Tour	FTO	Hardware	Leak on pipe cap disables two trains of charging HPI. BIT inlet valves were closed to isolate it.	1.3E-06
Sequoyah 1	32789033	12/16/89	Alarm	FTO	Design	RWST level detector sensing lines froze. Only would affect recirculation phase of HPI not injection phase	4.8E-06
Sequoyah 2	32888005	2/12/88	Tour	FTR	Maintenance	Charging pump speed increaser lube oil pump failed. Wrong pump installed and gland seal bolts backed out; replaced speed increaser lube oil pump with wrong type during previous maintenance.	3.8E-04
Sequoyah 2	32890012	8/22/90	Test	FTR	Gas Binding	Operator observed fluctuations in pump flow and motor current on 2B-B and secured the pump; vented the pump casing. Same problem. Vented several times. Design problem; gas stripping at the CCP mini-flow line flow restricting orifices.	6.0E-04
Shearon Harris	40091008	4/3/91	Test	FTR	Design	Damage to relief valves (1CS-755&1CS-744) and drain connections (upstream of 1CS-754) on these AMF lines were such that a significant portion of the safety injection flow would have been diverted from the RCS.	6.3E-03

Table 19. NRC Information Notices related to the HPI system during this study period.

Information Notice	Summary
IN 97-52	Vogtle: Lack of cooling water flow to SI pump motor coolers. Incorrect heat exchanger plenum and gasket installation caused the problem. (Issue for medium break LOCA)
IN 97-46	Oconee 2: Leaking cracked weld in unisolable section of HPI line. Thermal cycling during heat up and cooldown and alternate heating and cooling of the weld due to intermittent mixing hot RCS liquid and cool makeup water. (IN 82-09 and GL 85-20 address similar issues)
IN 97-76	Potential degradation of throttle valves in the high and intermediate-head SI pump flow paths due to high differential pressure causes cavitation and valve erosion. Thereby pumps may reach “run out” causing pumps to be stopped earlier than necessary.
IN 97-40	Nitrogen accumulation from back-leakage from Safety Injection Tanks result in water hammer (Happened in LPSI; reduced pressures in LPSI allow nitrogen to come out of solution and form gas voids. Potential problem for interfacing SI systems.)
IN 97-38	Oconee 3: Common mode failure of HPI pumps. Both HPI pumps became hydrogen bound due to taking suction from empty tank (both level transmitters failed in common mode; due to drained reference leg of let down storage tank. The isolation valve for this tank remains open on SI signal).
IN 95-18	Haddam Neck: Susceptible pressure locking of injection MOVs. Problem also addressed in IN 95-14 and GL 89-10.
IN 94-90	Salem 1: Reactor trip and multiple safety system actuation. Train B of SI logic did not actuate due to wrong logic. Solid state protection system mismatch due to response sensitivity to the steam flow input relays.
IN 94-76	Sequoyah 1&2, Callaway, Shearon Harris, DC Cook 1&2, Braidwood 1, Failures of charging/SI pump shafts. Operating under abnormal conditions (gas entrainment, void formation, or other abnormal conditions) may be contributing to the failures. (Issue also addressed in IN 80-07)
IN 94-29	PaloVerde 2, Parallel operation of multiple pumps (3 charging and 1 boric acid and when switching from VCT to RWST) causes low suction pressure and trip a charging pump during SGTR event.
IN 92-61	Shearon Harris: HHSI degraded due relief valve and drain line failure in the alternate minimum flow (AMF) system as a result of water hammer. The degraded AMF would divert SI flow away from RCS. Air left in piping after test & maintenance causes the water hammer.
IN 92-85	H.B. Robinson, foreign material blocking flow (20% SI flow reduction).
IN 90-64	Haddam Neck: Common mode failure of both high-point vent isolation valves in the suction vent line that connects charging pumps to VCT. Failure of these valves to isolate during a LOCA could drain down the VCT and allow Hydrogen gas (and any other gas collected in the vent line) to be transported to the suction of the charging pumps by way of the high-point vent charging pump suction line.
IN 88-01	Farley 2: Safety Injection pipe failure. Issues similar to IN 97-46
IN 88-23	Farley 1: Gas binding of HPSI pumps. Hydrogen entrained in suction line due to suction header lines are 32 ft. above VCT. If local pipe pressure in the lines between VCT and HPSI pump suction nozzles is less than VCT pressure, dissolve hydrogen will come out of solution and be swept through the pumps. Four IN Supplements have been issued since this IN covering 1988 through 1992.

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Appendix A

HPI Data Collection and Analysis Methods

Appendix A

HPI Data Collection and Analysis Methods

To characterize high pressure safety injection (HPI) system performance, operational data pertaining to the HPI system from 72 U.S. commercial nuclear pressurized water reactor plants having HPI systems were collected and reviewed. This appendix provides descriptions for the operational data collection and the subsequent data characterization for the estimation of HPI system unreliability.

The descriptions below give details of the methodology, summaries of the quality assurance measures used, and discussions of the reasoning behind the choice of methods.

A-1. SYSTEM CHARACTERIZATION

The HPI systems for the plants used in this study differ considerably among the plants. The plants have different numbers of trains and operating features. In an effort to collect and properly classify the operational data from the plants, it was necessary to group the plants that had similar system configurations. This grouping resulted in partitioning the plants into 6 different HPI design classes.

To estimate unreliability for each HPI design class, it was necessary to collect information on the frequency and nature of demands. For the reliability estimation process, demand counts must be associated with failure counts. To estimate HPI demands and associate the failures with the demands consistently within each group and where possible for the industry, the HPI system was partitioned into segments to facilitate the subsequent analysis. These system segments are (1) RWST suction, (2) pump train and discharge piping, (3) pump injection header, (4) shared injection header (5) cold leg injection, and (6) Instrumentation and Control (i.e., actuation circuits) subsystem. The composition of the various components for each segment may differ among plants within an HPI design class. However, the overall function of the segment for each is approximately the same. The following are descriptions of the types of segments found among the various HPI design classes and the components found in each segment. In each description, the segment name is followed in parentheses with the general label used in the simplified block diagrams.

1. The RWST suction segment (RWST-SUCT) includes all piping and valves (including valve operators) from the RWST/BWST to the pump suction header. Also included in this segment are the components and equipment used for VCT isolation and the transfer of pump suction to the RWST.

2. The pump train and discharge piping segment (*ff*-PUMP*x*) includes the motor and associated breaker, but excludes the electrical power bus itself. Also included with this segment are the pump and associated piping from (and including) the pump suction header up to and including the discharge header valves, and associated valve operators. The minimum flow and test recirculation line is included if the associated tap off connects prior to the discharge isolation valve. The HPI systems consist of either high-head pumps (CC-PUMP*x*), intermediate-head pumps (SI-PUMP*x*), or a combination of both. Note, some plants have a common suction header arrangement instead of a dedicated suction path within the pump train. For plants having this configuration, an independent segment labeled PUMP-SUCT was used to model these systems.

3. The pump injection header segment (*xx*-INJ-HDR) includes the piping and valves from the pump discharge isolation valve up the cold-leg or cold-leg injection segment depending on whether multiple injection segments feed a common cold-leg injection header. This segment begins downstream from the pump discharge isolation valve (or discharge header) and terminates at the point connecting to alternate injection paths (or cold-leg for plants that do not have a shared injection header since these plants have dedicated injection paths from the pumps to the cold legs). Included with the segment are the associated valves and valve operators, the injection valve and control logic, and the test recirculation line where applicable.

4. The shared injection control segment (*xx*-INJ-HDR) applies to plants where the pump discharges to a shared header with flow to the cold-leg being regulated in this common line. (The *xx* prefix refers to high head, CC, or intermediate head, SI.) This segment includes the piping and valves from (but not including) the pump discharge isolation up to the cold-leg for plants with only one injection header per cold-leg. For plants with more than one injection header per cold-leg or where the injection path connects with another injection systems, the injection control segment includes piping up to the connection point for the alternate injection path. Included with this segment are the associated valves and valve operators, the injection/isolation valve and the control logic, and the test recirculation line where applicable.

5. The cold-leg (loop) injection segment (LOOP *x*-INJ *y*) includes the check valve(s) and associated piping downstream of the common injection header segments. This segment generally includes the last check valves in the injection system piping immediately upstream of the RCS cold leg.

6. The Instrumentation and Control subsystem (ACT-CHANL *x*) includes the circuits for initiation of the HPI system. It includes sensors, transmitters, instrument channels, and analog or solid state components used for HPI train actuation

Each plant's HPI system has several but not all of these segment types. Appendix D provides block diagrams of typical configurations of these segments for each of the six HPI design classes. Also, plant and design-class specific fault trees were developed to describe how the HPI system fails in terms of these segment types.

A-2. DATA COLLECTION AND CHARACTERIZATION

The HPI system operational data used in this report are based on LERs selected using the SCSS database. The SCSS database was searched for all records that explicitly identified an engineered safety feature (ESF) actuation or failure associated with the HPI system for the years 1987 through 1997. To ensure as complete a data set as possible, the SCSS database was also searched for all safety injection actuations for plants that have an HPI system. These records potentially provide an additional source of HPI actuations because (1) the HPI system is typically demanded as a result of a safety injection demand and (2) HPI may be required to start following a reactor trip as a result of low pressurizer level (for example, as the result of overcooling the reactor coolant system).

These potential differences in what a plant may or may not report are not evaluated in this study. It was assumed for this study that every plant was reporting HPI ESF actuations and failures consistently as required by the LER Rule, 10 CFR 50.73, and the guidance provided in NUREG-1022, *Event Reporting Systems 10 CFR 50.72 and 50.73.*[A-1] (HPI ESF actuations were found and reported as ESF actuations for all plants in the study.) HPI events that were reported in accordance with the requirements of 10 CFR 50.72 (Immediate Notification Reports) were not explicitly used in this study because the LERs (i.e., 10 CFR 50.73 reports) provided the more complete event descriptions needed to determine successful operation or failure of HPI.

Sections A-2.1 and A-2.2 below describe methods for acquiring the basic operational data used in this study.

A-2.1 Inoperability Identification and Classification

The information encoded in the SCSS database, and included in this study, encompasses both actual and potential HPI failures during various plant operating conditions and testing. In this report, the term *inoperability* is used to describe any HPI component malfunction either actual or potential, except an ESF actuation, in which an LER was submitted in accordance with the requirements identified in 10 CFR 50.73. It is distinguished from the term *failure*, which is a subset of the inoperabilities for which a segment of the system was not able to perform its safety function. Specifically for an event to be classified as a failure, when considering all the data provided in the full text of the LER, the segment would not have functioned successfully upon demand.

The HPI system is a safety system, and any occurrences in which the system was not fully operable, as defined by plant technical specifications, are required by 10 CFR 50.73 to be reported in LERs. However, because the HPI system consists of redundant trains, not all train level inoperabilities are captured in the LER data. Specifically, a plant is not required to report a single train inoperability unless the malfunction resulted in a train outage time in excess of technical specification allowable outage times, or resulted in a unit shutdown required by technical specifications. Otherwise, any occurrences where a train was not fully operable would not be reported. For example, no LER would be required to be submitted if, during the performance of a surveillance test, a intermediate-head pump failed to start but the redundant train(s) were operable and the cause of the failure to start was corrected with operability restored prior to expiration of the technical specification limiting condition for operation. This reportability requirement effectively removes any surveillance test data from being considered for the unreliability estimate except for those HPI system segments that do not have redundancies (e.g., RWST suction path). However, for ESF actuations, all component failures that occurred as part of the ESF actuation were assumed to be described in the narrative of the LER as required by 10 CFR 50.73(b)(2)(ii). Because all ESF actuations are reportable as required by 10 CFR 50.73(a)(2)(iv), the failures that occurred during an ESF actuation are assumed to be complete.

A-2.1.1 Failure Classification

Each of the LERs identified in the SCSS database search was reviewed by a team of U.S. commercial nuclear power plant experienced personnel, to properly classify each event and to ensure consistency of the classification for each event. Because the focus of this report is on risk and reliability, it was necessary to review the full text of each LER and classify or exclude events based on the available information reported in the LER. Specifically, the information in this report necessary for determination of reliability, such as classification of HPI failures, failure modes, failure mechanisms, causes, etc. were based on the independent review of the information provided in the LERs.

Two engineers independently evaluated the full text of each LER from a risk and reliability perspective. At the conclusion of the independent review, the data from each independent LER review were combined, and classification of each event was agreed upon by the engineers. The events identified as failures that could contribute to system unreliability were peer reviewed by the NRC technical monitor and technical consultants that have extensive experience in reliability and risk analysis. The peer review was conducted to ensure consistent and correct classification of the failure event for the reliability estimation process.

The events identified in this study as segment failures represent actual malfunctions that prevented the successful operation of the particular segment. Segment failures identified in this study are not necessarily failures of the HPI system to complete its mission. Specifically, a pump segment may have failed to start; however, the redundant pump segment may have responded as designed for the mission. Hence, the system was not failed. Examples of the types of inoperabilities that are classified as segment failures include:

- Malfunctions of the initiation circuit prevent a pump from starting in automatic.
- The test recirculation valve was not fully closed after a surveillance test, and as a result, diverted sufficient flow during an SI condition requiring inventory makeup to the reactor coolant system.
- A pump is shut down by operator action for any reason with a SI signal at or below the initiation setpoint.
- Gas binding, sludge or foreign material in the pump casing results in a reduction in pump capacity.
- A damaged pump impeller or shaft as a result of stress corrosion cracking or fatigue due to gas binding experiences.

Based on the review and classification of the LERs, the following segment failure modes were observed in the operational data:

- Maintenance-out-of-service (MOOS) occurred if, because of maintenance activities, the segment is prevented from starting automatically during an unplanned demand. This failure mode only applied to the pump segments. Examples of the types of events classified as MOOS include an pump motor’s circuit breaker being racked out for repairs.
- Failure to start (FTS) occurred if the pump segment was in service but failed to automatically start or manually start, and obtain sufficient pressure and flow. This failure mode applied only to the pump segments. There was no minimum operational time associated with this failure mode. Specifically, if the pump successfully started as evidenced by achieving the required flow and pressure, it was considered a successful start, even though the pump may have failed to maintain required flow and pressure a short time later. Examples of the types of failures classified as FTS include stopping the pump as a result of gas accumulation in the suction line, causing erratic operation of the pump that required the motor to be shut down before the required flows and pressures are observed, a damaged pump impeller, and a pump motor’s circuit breaker failing to close on an initiation signal.

  In addition, events in which the pump successfully started and later failed as a result of a failure mechanism that was present at the time of the demand were classified as a failure to start. Also, a failure may have been classified as a failure to start if the pump circuit breaker tripped on over-current a few minutes after a successful start as a result of the over-current protection relay setpoint being set at the normal running amperage versus a higher amperage setpoint as required.

- Failure to run (FTR) occurred if, at any time after the pump segment was delivering sufficient pressure and flow, the segment failed to maintain sufficient pressure and flow while it was needed due to a time-dependent mechanism not present at the time of the demand. This failure mode applied only to the pump segments. This failure mode was not associated with any minimum required operational time prior to the failure (i.e., no minimum running time restrictions applied for the failure to be classified as a failure to run). However, the failure mechanism had to be time dependent. Specifically, the mechanism of the failure had to be related to operation of the pump, and the failure had to occur after the pump was delivering required flow and pressure. Examples of the types of failures classified as FTR include the pump discharge relief valve lifting and diverting flow, erratic pump operation that required the pump to be shut down at anytime after the required flows and pressures are observed, the pump ventilation damper failed to open on pump start, and racking out the spare pump motor’s circuit breaker that results in tripping the running pump due to interlock design.

- Failure to operate (FTO) occurred if the segment could not perform its required safety function when needed. This failure mode applied to the segments other than the pump segments. Examples of the types of failures classified as FTO include Train B failed to actuate due to a wire interfering with a relay plunger, low safety injection flows due to mispositioned valves/stem locks, relief valve (common cold leg injection line to the Reactor Coolant System (RCS) lifted and failed to reseat (both trains of the HPI system were declared inoperable), and the HPI loop injection valve did not open due to a blown fuse during an inadvertent SI actuation during cold shutdown.

- Failure to operate (FTO) of the RWST suction path and associated piping faults segment occurred if this segment could not perform its required safety function when needed. Also included under this heading is any isolation failure of the VCT that lead to the failure of the HPI suction source.

In addition to the basic failure mode, each failure event was distinguished according to whether the following two attributes apply:

- Common cause failure (CCF) occurred if two or more segments could not perform their required safety function as a result of a common failure mechanism. Examples of the types of failures that were classified as a common cause failure include the following: RWST level detector lines frozen, a charging pump speed increaser lube oil pump failed due to wrong pump installed and gland seal bolts backed out during previous maintenance (two pumps affected) and the potential to gas bind all 3 HPI pumps from the suction piping accumulating gas. (The volume of gas trapped in the piping exceeded the manufacturer’s limit of gas volume that the pump would safely pass without causing damage to the pump.)

- Error of commission (EOC) occurred if the HPI system was rendered inoperable by operator action when the system was demanded by an SI signal. An example is an operator inappropriately bypassed actuation of the engineered safeguards (ES) prior to the setpoint. However the shift supervisor directed ES out of bypass and ES actuation was initiated.

For the events associated with the injection header/cold leg injection path segments, some LERs identified a degraded flow condition to one or more cold legs. In these events typically no actual flow rates were provided, or was a qualitative discussion of the relationship between the flow rates and technical specification or safety analysis report requirements identified. In these events where degraded flow was indicated, the corrective actions associated with the degraded flow condition were reviewed. In some cases the corrective actions for the degraded flow identified lengthy and extensive testing and inspections, along with component replacements. Because of the extensive corrective actions associated with the identified degraded flow it was assumed that the degraded flow was at the very least not sufficient to meet technical specification operability requirements. As a result, the events that identified degraded flow in an injection header/cold leg injection path segment were classified as failures of the associated injection header/cold leg injection path segment based on the corrective actions taken by the plant. For the LERs that identified an injection header/cold leg injection path segment flow problem where a flow rate was provided, the segment was classified as failed if the LER stated that the flow rate was less than technical specification minimum flow rate. Overall, there was no assigned minimum flow value for determining a failed injection header/cold leg injection path segment for this report (e.g. less than 90% of the technical specification minimum). If the plant identified a flow rate less than technical specification minimums or a degraded condition which required significant corrective actions the injection header/cold leg injection path segment was classified as failed.

This classification was based on the need for the injection header/cold leg injection path segment to function successfully for a period of time until the plant is cooled down to the point where the residual heat removal system is able to be placed in service.

Recovery from initial failures is also important in estimating reliability. To recover from a failure of any segment, operators have to recognize that the segment is in a failed state, and restore the function of the segment without performing maintenance (for example, without replacing components). An example of such a recovery would be an operator (a) noticing that the pump tripped but did not start automatically and (b) manually starting the pump from the control room. Each failure during an unplanned demand was evaluated to determine whether recovery by the operator occurred.

In addition to the failures that were actually recovered by plant operators, there were some failures that operators elected not to recover from because a redundant segment of the system was performing the intended function. As an example, if a pump failed to start and the redundant pump started and was operating properly, operators would not normally pursue recovery of the failed pump segment if the reactor/plant parameters were being returned to normal. Similarly, failures that occur during testing are not typically recovered. As a result, each failure that was not actually recovered was reviewed to determine, using engineering judgment, if the failure could have been recovered if given the need to recover the failed segment. Specifically, using the above example of the pump failing to start, engineers assessed whether, given the information, specifically the failure mechanism, in the LER, the likelihood was high that the operators would have been able to restart the pump without any performing any corrective maintenance on the pump. For example, if the failure to start was attributed to the automatic start circuitry, this failure was typically judged to be recoverable because manual starting is possible. However, if the pump failing to start was a mechanical failure of the pump shaft, the failure was judged to be nonrecoverable even though the pump was not needed at that time.

In addition to the failure mode data, other information concerning the event was collected from the detailed review of the full text of the LER:

- For events classified as failures to run, the run time prior to failure, if provided in the LER

- The segment and component involved

- The method of discovery of the event (e.g., unplanned demand, surveillance test, engineering design review, or other routine plant operations)

- The cause of the event (design, hardware, maintenance, personnel, procedure, support system, gas binding, or environment).

The assessment of the cause of the failures was based on the independent review of the data provided in the LERs and does not correspond to the "Cause Codes" provided by SCSS. The eight cause categories selected for this study were based on the data provided in the LERs and engineering judgment. The cause classification of each inoperability was based on the immediate cause of the event and not on a root cause analysis that may be provided by the plant. Specifically, the mechanism that actually resulted in the segment failing to function as designed was captured as the cause. This methodology precluded categorization of many of the failures as a management deficiency or simply a personnel error which many LERs identify as a cause. Definitions and explanations for the assigned cause codes follow:

- *Design*—Inoperabilities that were the result of incorrect design specifications of the system were classified as "Design." These failures were not related to inaccuracies associated with operating/maintenance procedures or operator/technician error. Specifically, if a technician was following the approved procedure for setting torque switches and it was later determined that the settings of the torque switches were too low based on an evaluation of the assumptions and associated calculations used to determine the switch setpoints, the cause was classified as "Design." This category included both actual and potential failures. Examples of the types of inoperabilities that were assigned to the "Design" category include torque switches for motor-operated valves set too low/high, RWST level detector lines frozen, and design logic (the safety injection trains were blocked when the reactor trip breakers were open and safety injection actuation had occurred) errors.

- *Hardware*—Inoperabilities that were the result of an actual component failure that resulted in HPI system to satisfactorily perform its intended function were classified as "Hardware." These failures were not related to technician error associated with improperly performed maintenance activities resulting in a failed component. Examples of the types of inoperabilities that were assigned to the "Hardware" category include cracked pump rotor bars, blown fuses that were the proper size, worn packing that prevents proper operation of valves or pumps, worn pump impeller wearing rings, pump failures as of worn or loose parts, and short circuits associated with instrumentation and control circuits.

- *Maintenance*—Inoperabilities that were the result of a technician failing to perform a maintenance activity in accordance with established procedures that results in failure of the system to operate properly when demanded, were classified as "Maintenance." These failures were not related to errors associated with maintenance procedures resulting in a failed component. An example of inoperabilities that were assigned to the "Maintenance" category include installing the wrong pump during a previous maintenance resulting in several pump failures.

- *Personnel*—Inoperabilities that were the result of an operator failing to operate the system as required by procedure were classified as "Personnel." These failures were not related to errors associated with maintenance activities resulting in a failed component. This category primarily included actual failures. Examples of the types of inoperabilities that were assigned to the "Personnel" category include operating a valve to the open position when it was intended to be closed, shutting both the pump discharge and minimum flow isolation valves during pump operation, failing to place the system in standby operation when required by plant technical specifications, and blocking any system automatic start function when required to be operational by plant technical specifications.

- *Procedure*—Inoperabilities in which personnel properly followed either an operations or maintenance procedure and rendered a segment inoperable, because of an error in the procedure, were classified as "Procedure." Examples of the types of inoperabilities assigned to the "Procedure" category include the opening switches that disable ESF actuation being because the procedure was incorrect, motor cooling for a pump had been significantly degraded due to improper gasket installation and incorrect assembly of the two motor coolers, or performing the system check valve testing in accordance with a surveillance procedure that rendered both HPI trains inoperable.

- *Environment*—Inoperabilities that were the result of a piping blockage/restrictions due to foreign material were classified as "Environment." Examples of inoperabilities falling under this cause category are frozen recirculation lines and obstructions in the pump recirculation line.

- *Support system*—HPI segment inoperabilities that were the result of a failure mechanism associated with a system outside of HPI but necessary for the operation of HPI were classified as "Support system." Generally, these failures were outside the system boundaries for this study and, as a result, were not used in the unreliability estimates provided in this report. However, failure of support system did result in occurrences for which HPI could not respond to a SI actuation signal. The types of failures caused by support system failures include HPI inoperabilities from losses of 4,160-Vac bus with the diesel generator failing to provide power to the affected bus, air binding of component cooling water thereby making the HPI pumps inoperable, etc.

- *Gas Binding*—Inoperabilities that were the result of gas (air, hydrogen, etc.) in the pump train suction piping were classified as "Gas binding." This category was defined because this has been a reoccurring problem that has been analyzed and documented in past NRC Inspection Notices. This cause category was created to track these specific events.

A-2.1.2 Additional Classification Guidelines

The information in the analysis section of some LERs lead to the determination that an HPI segment would have been able to perform as required even though it was not operable as defined by plant technical specifications. For example, consider an event where the pump discharge piping was found not to have the required number of seismic restraints, and therefore was not operable as defined by plant technical specifications. This event would not be classified as a failure since the system would function during an HPI demand unless the HPI demand coincided with an earthquake. Other inoperabilities **not** classified as failures include configuration errors associated with the floor drain system, failures that occurred after the event was terminated when the system was being restored to standby, and valves failed in the position required for emergency response.

In addition, administrative problems associated with HPI were not classified as failures. As an example, the LER may have been submitted specifically for the late performance of a technical specification required surveillance test. This event would not be classified as a failure in this study if a test conducted after the discovery of the missed surveillance shows that the segment would still be capable of functioning as designed given a demand for the segment. If the segment failed the subsequent surveillance test, the event would have been classified as a failure.

Other events found in the SCSS database search were explicitly removed from consideration from the unreliability estimate even though the events were captured in the SCSS database as failures of the HPI system during an unplanned demand. These events were instances in which the failure mechanism was outside the system boundary for this study or were support system failures. However, if the failure prevented successful operation of the HPI system during an unplanned demand, the event was captured for informational purposes only. Examples of the types of events explicitly excluded from the unreliability estimate include a de-energized emergency bus that prevented the start of an motor-driven pump, malfunction of protective/actuation circuitry that is not specifically dedicated to the HPI system, and malfunction of the emergency diesel generator sequencer circuitry.

Additional differences between the events captured as failures in this study and the events captured as failures in the SCSS database would be observed because of the definition of failure used in this study and that used in the SCSS database. Specifically, a system that is out of service for maintenance at the time of an unplanned demand would not be classified as a failure in the SCSS database; however, it would be classified as a failure for this study in an effort to estimate a maintenance-out-of-service probability. Also, the SCSS database would identify a system as failed if the system is out of service for pre-planned maintenance and another system subsequently fails. As an example, the train “A” HPI pump is out of service for maintenance when the “B” emergency diesel generator fails a surveillance test. The SCSS database would identify both systems as failed; however, pre-planned maintenance of the HPI system without a corresponding demand is not considered a failure in this study.

As a result of the review of the LER data, the number of events classified and used in this study to estimate HPI unreliability will differ from the number of events and classification that would be identified in a simple SCSS database search. Differences between the data used in this study and a tally of events from an SCSS search would stem primarily from the reportability requirements identified for the LER and the exclusion of events whose failure mechanism is outside the system boundary. Because of these differences, the reader and/or analyst is cautioned from making comparisons of the data used in this study with a simple tally of events from SCSS without first making a detailed evaluation of the data provided in the LERs from a reliability and risk perspective. The results of the LER review and classification are provided in Appendix B, Section B-2.

A-2.2 Characterization of Demand and Exposure Time Data

To estimate unreliability, information on the frequency and nature of HPI demands was needed. For the reliability estimation process, demand counts must be associated with failure counts. The selection of sets of events with particular system demands determines the set of failures to be considered in the reliability estimation (namely, the failures occurring during those demands). Two criteria are important in selecting event sets for reliability analysis. First, useful event sets must, of course, be *countable*. Reasonable assurance must exist that the number of events can be estimated, that all failures associated with these events will be reported, and that sufficient detail will be present in the failure reports to match the failures to the applicable event set.

The second criterion is that the demands must reasonably approximate the conditions being considered in the unreliability analysis. The unplanned demands or tests must be *rigorous* enough that successes as well as failures provide meaningful system performance information. The determination of whether each demand reasonably approximates conditions for required accident/transient response depends in turn on the responses measured in each failure probability estimate.

As explained in further detail below, the unplanned demands meet the countable and rigorous requirements, but except for the RWST suction segment, use of surveillance test data is precluded because the failures are not generally reportable and thus are not countable.

A-2.2.1 Unplanned Demands

For the purposes of this study, an unplanned demand was defined as an event requiring either the system or segment of the system to perform its safety function as a result of a valid initiation signal that was not part of a pre-planned evolution. Other plant conditions may have also resulted in an unplanned demand of HPI based on the plant-specific design of the HPI initiation circuit. These initiations of HPI were also included in the study if they resulted from a valid signal.

Spurious signals or those inadvertent SI initiation signals that occurred during the performance of a surveillance test were classified as demands. For example, shorting test leads or blown fuses that resulted in a demand signal were counted as a valid demand of HPI's safety-related function.

The LERs identified from the SCSS database search were reviewed to determine the nature and frequency of HPI unplanned demands. Specifically, each LER was reviewed to determine what segment(s) of the system were demanded. To determine which segment(s) of the system were demanded, the IPE and/or Final Safety Analysis Report (FSAR) for each plant was reviewed to determine the initiation setpoints and operating characteristics of the system for the specific plant. In addition to the setpoints and operating characteristics, the plant-specific system schematic for HPI was also reviewed. This review provided the plant-specific background information needed to evaluate from the full text of each LER which segment(s) of the system were demanded.

The identification of the system initiation setpoints, operating characteristics, and schematic for the system was necessary to capture the unplanned demand frequency because many LERs simply stated that all systems functioned as designed. However, the full text of the LER would describe plant conditions that should have resulted in an unplanned demand of HPI. For example, an LER might just state that an SI occurred and the reactor coolant system pressure during the event. Comparing the RCS pressure stated in the LER to the HPI information provided in the FSAR for the particular plant, it was determined whether the RCS pressure was greater than the shutoff-head of the running HPI pumps. If so, then the HPI pumps would run in a recirculation mode and no HPI flow would be provided to the cold legs until RCS pressure dropped to below the pump's shutoff head. For this event, the segment containing the check valves (typically, the cold leg injection path) that isolate RCS from the HPI piping would not receive any HPI flow. For this segment, no demand for the segment was recorded in the actuation database. Otherwise, a demand would be recorded for the cold leg injection path segment.

The review of the unplanned demands also included capturing in the database the average pump run times (total run time for all running pumps during the event) specified in the LER for each type of pump that received a demand to start and run during the events.

The results of the LER review and evaluation are provided in Appendix B, Section B-2.

A-2.2.2 Surveillance Tests

Reasonable assurance must exist that all failures associated with surveillance tests will be reported. Because surveillance test failures of a single train would not be required to be reported, as discussed previously, the number of failures found in the LERs may be less than the number that actually occurred. This would result in a reliability estimate that would be based only on a subset of the actual failures. Consequently, no surveillance test data were considered for the reliability estimate except for the RWST suction segment.

A-2.2.3 Pump Run Times

An average run time was computed from the unplanned demand LERs for which run times were specified. Estimated run times were then projected for the pump demands with unknown run times. Such a run time would be zero if the demand was followed by an unrecovered maintenance-out-of-service or failure to start.

Using projected run times based on averages of known times for unknown run times introduces additional uncertainty in the failure rate estimates. The uncertainty introduced by using projected run times has not been quantified.

A-2.2.4 System Operation Time

In addition to the unreliability analysis, the reported system unplanned demands were characterized and studied from the perspective of overall trends and the existence of patterns in the performance of particular plant units. These assessments were based on frequencies of occurrence per year. Since valid demands for the HPI system only occur when a plant is operational, the operational times associated with the NRC's Performance Indicator Program were used to normalize the unplanned demand counts. For each plant and year, the plant's operational time was computed as a fraction of a year. Periods prior to the low-power license date or after a plant's decommission date were excluded.

To evaluate trends with respect to plant age, it was assumed that the age of the HPI system is the same as the total calendar time of the plant from the low-power license date. Each plant's HPI unplanned demand count was normalized by the plant's operational time during the study period, and the resulting frequencies were trended against the plant's low-power license date (i.e., age).

A-3. ESTIMATION OF UNRELIABILITY

Four groups of estimates were evaluated for the HPI system study: independent failure probabilities and rates, total failure probabilities and rates, recovery probabilities, and common cause failure (CCF) probabilities. The independent failure probabilities and associated recovery probabilities (as applicable) were used directly in the fault trees developed to quantify the unreliability of the HPI system. The total failure probabilities (i.e., the independent failure probabilities since no CCF events were identified in the unplanned demands) were developed for use with common cause *alpha* factors, discussed Section 3.1.3 of this report, to quantify the common cause portion of the fault trees.

In all four groups of estimates, the primary data are failures and demands, leading to estimates of failure probabilities. In the statistical analysis process, rate-based analysis was performed for failure to run for the high-head and intermediate-head pumps. The rate-based estimates were developed for use in comparing the operating experience to the PRA/IPE results. For FTR, most of the operational demands were relatively short compared with the longer mission times (several hours to 24 hours) typically assumed in PRAs. Rate-based models specifically account for the fact that unreliability tends to increase as the mission time gets longer.

The selection of particular failure modes in the four groups was dictated by the requirements of fault trees developed for each plant's HPI system. Failure probabilities were quantified for each of the types of segments described in Section A-1. For the pump trains, separate estimates were developed for each failure mode for each train type. All these estimates were based on only independent failures.

Recovery modes were modeled for failure modes having at least one failure and for which recovery was possible. In the PRA/IPE comparisons, the recovery failure modes are included even though PRAs typically model recovery separately. The recovery event defined for this study encompasses only those failures for which no actual diagnosis and physical repair of a failed component occurred. Examples of these events include the recovery of a failure related to automatic start that was recovered by the operator manually starting the system. This kind of recovery is different from PRA-defined recoveries that require diagnosis and actual repair of failed equipment that will restore the system to operational status. Generally, PRAs take credit for the recovery failure modes defined for this study if procedures or training direct the operator to perform these actions.

Based on the types of events observed in the LER data, CCF was quantified for FTS for high-head and intermediate-head trains, for FTR for high-head and intermediate-head trains, for FTO for the injection header segments. For these five CCF classifications, LER-based estimates were developed. The total failure probabilities (or rates for the risk-based model for FTR) are based on relevant segment failures and the associated counts or times for each segment demand.

The common cause factors or alpha factors were derived using data from both LERs and the Nuclear Plant Reliability Data System (NPRDS) maintained by the Institute for Nuclear Power Operations (INPO). The derivation, as described in Reference A-2, used data for the HPI system during the 1987–1997 study period and included partial as well as total losses of function. For failure of the motor-driven pumps to start and failure to run, both the pump and the associated motor were considered. The alpha factors were developed for the high-head pumps and intermediate-head pumps. Data for motor-operated valves were considered for the injection header segments.

The applicable individual failure probabilities, failure rates, and mission time were combined to estimate the total unreliability. Estimating the unreliability and the associated uncertainty involves two major steps: (1) estimating probabilities or rates and uncertainties for the different failure modes and (2) combining these estimates. These two steps are described below in Sections A-3.1 and A-3.2.

A-3.1 Estimates for Each Failure Mode

Estimating the probability for a failure mode requires a determination of the failure and demand counts or exposure time in each data set, a decision about what data may be pooled, and a method for estimating the failure probability and assessing the uncertainty of the estimate.

A-3.1.1 Demand and Failure Counts

For the independent failure probabilities, the unplanned demands were counted by failure mode as follows. The total number of demands was obtained as described in Section A-2.2 for each of the other segments defined in Section A-1. These counts were used directly for the injection header segments and cold leg injection segments. For the pump trains, the number of demands applies to the MOOS failure mode. The number of demands for FTS was taken to be the number of train demands minus the number of unrecovered MOOS events. With one exception, the number of demands to run was the number of demands for FTS minus the number of unrecovered FTS events.

The unplanned demands were associated with all the failures on unplanned demands for the total failure probability estimates. For the independent failure probability estimates, all identified demands were counted, but failures associated with CCF events were excluded. (For the HPI study, there were no CCF events in the operating experience based on the unplanned demand data.)

A run time was known or estimated for each of the events counted for FTR demands, as described in Section A-2.2.3.

For each recovery mode, the number of demands is the number of corresponding failures, and the number of failures is the subset of the failures that were judged to be not recoverable. Since the failure data was sparse, the failures identified in the test and non-SI events were evaluated with regard to recovery. Including these events into the recovery analysis reduced the uncertainty of the nonrecoverable failure probabilities.

A-3.1.2 Data-Based Choice of Data Sets

The data were reviewed to see if pump train events could be combined across high-head and intermediate-head pump types. For this assessment, failure probabilities and FTR rates and their associated 90% confidence intervals were computed separately for each group of data. The confidence intervals for probabilities assume binomial distributions for the number of failures observed in a fixed number of demands, with independent trials and a constant probability of failure in each data set. Similarly, the confidence intervals for FTR in the risk-based model assume Poisson distributions for the number of failures observed in a fixed time period, with independent failures and a constant failure occurrence rate in each data set. A comparison of the confidence intervals gave an indication of whether the data sets could be pooled.

The hypothesis that the underlying maintenance-out-of-service probability for the high-head and intermediate-head pump trains is the same was tested. A chi-square test was performed to assess whether the data provide evidence for separate probabilities. A similar test was performed to assess whether pooling might be reasonable for the FTS rates. Decisions concerning the pooling of the data were made based on the engineering feasibility of pooling together with the results of the statistical tests.

A-3.1.3 Estimation of Failure Probability Distributions using Demands

The probability of failure on demand was modeled using Bayesian tools, with the unknown probability of failure for each failure mode represented by a probability distribution. An updated probability distribution, or *posterior* distribution, is formed by using the observed data to update an assumed *prior* distribution. One important reason for using Bayesian tools is that the resulting distributions for individual failure modes can be propagated easily, yielding an uncertainty distribution for the overall unreliability.

Bayes Theorem provides the mechanics for this process. The prior distribution describing failure probabilities is taken to be a *beta* distribution. The beta family of distributions provides a variety of distributions for quantities lying between 0 and 1, ranging from bell-shape distributions to J- and U-shaped distributions. Given a probability (p) sampled from this distribution, the number of failures in a fixed number of demands is taken to be binomial. Use of the beta family of distributions for the prior on p is convenient because, with binomial data, the resulting posterior distribution is also beta. More specifically, if *a* and *b* are the parameters of a prior beta distribution, *a* plus the number of failures and *b* plus the number of successes are the parameters of the resulting posterior beta distribution. The posterior distribution thus combines the prior distribution and the observed data, both of which are viewed as relevant for the observed performance.

The data were too sparse to show significant differences between groups (such as plants). Therefore, the data were pooled and then modeled as arising from a binomial distribution with a failure probability *p*. The assumed prior distribution was taken to be the Jeffreys noninformative prior distribution.[A-3] More specifically, in accordance with the processing of binomially distributed data, the prior distribution was a beta distribution with parameters, $a = 0.5$ and $b = 0.5$. This distribution is diffuse and U-shaped, and has a mean of 0.5. Results from the use of noninformative priors are very similar to traditional confidence bounds. See Atwood[A-4] for further discussion.

The data were pooled, not because there were no differences between groups (such as plants), but because the sampling variability within each group was so much larger than the variability between groups that the between-group variability could not be estimated. The dominant variability was the sampling variability, and this was quantified by the posterior distribution from the pooled data. Therefore, the simple Bayes method used a single posterior distribution for the failure probability.

A-3.1.4 Assessments and Estimation of Failure Probability Distributions Using Rates

The FTR probabilities for each train type were derived from rates of occurrence rather than from failures and demands. Bayesian methods similar to those described above were used. The analyses for rates are based on event counts from Poisson distributions, with the Jeffreys noninformative prior distribution. The *simple Bayes* procedure for rates results in a gamma distribution with shape parameter equal to $0.5+f$, where f is the number of failures, and scale parameter $1/T$, where T is the total pooled running time. Engelhardt[A-5] gives details.

A-3.2 The Combination of Failure Modes

The failure mode probabilities were combined to obtain the unreliability. Two steps were used to obtain the reliability for the HPI system. First, simple algebra was used to combine failure and nonrecovery probabilities, thereby simplifying the system fault trees. In the second step, Monte Carlo simulation using the IRRAS software suite[A-6] allowed the quantification of the system unreliability and its uncertainty. These steps are discussed in more detail below.

A-3.2.1 Nonrecovery Probabilities and Rates

The algebra used to compute nonrecovery probabilities or rates and their uncertainty bounds for applicable failure modes was based on the simple fact that

$$\text{Prob}(A \text{ and } B) = \text{Prob}(A)*\text{Prob}(B).$$

In the application here, *A* is the event “failure with a certain failure mode” and *B* is the event “nonrecovery from the failure.” Since this expression is linear in each of the two failure probabilities, the estimated mean and variance of the probability of failing and not recovering can be obtained by propagating the means and variances of the two failure probabilities.

The process, described in more generality by Martz and Waller,[A-7] is as follows:

- Select appropriate beta distributions for each applicable basic failure mode and probability of nonrecovery.

- Compute the mean and variance of each beta distribution.

- Compute the mean of the nonrecovery probability for each case using the simple fact that the mean of a product is the product of the means, for independent random variables.

Compute the variance of the nonrecovery probability for each case using the fact that the variance of a random variable is the expected value of its square minus the square of its mean.

- Compute parameters for the beta distribution with the same mean and variance.

- Report the mean and the 5th and 95th percentiles of the fitted beta distribution.

For failure to run, based on a rate, a rate of nonrecovery was not computed. There were no observed failures to run in the SI actuation events.

The means and variances of the nonrecovery probabilities or rates calculated from the above process are exact. The 5th and 95th percentiles are only approximate, however, because they assume that the final distribution is a beta distribution for the probability of unrecovered failures or a gamma distribution for the nonrecovery rate. Monte Carlo simulation for the percentiles would be more accurate than this method if enough simulations were performed, because the output uncertainty distribution is empirical and not required to be among the shapes described by beta or gamma distributions. Nevertheless, the approximation seems to be close in cases where comparisons were made, and it greatly reduces then number of failure combinations for consideration in the HPI system unreliability quantification.

Because the data were sparse, the Jeffreys noninformative distribution was always used as the prior.

A-3.2.2 HPI System Unreliability

Four series of HPI system unreliability calculations were performed. Because of the complexity of the HPI system models, IRRAS was used to perform these analyses, rather than an extension of the moment-matching method of Section A-3.2.1. The series are as follows:

- Plant-specific operational models, using unrecovered maintenance-out-of-service, independent failures to start, and independent failure to run for each applicable train type. Recovery from high-head and intermediate-head maintenance and failure to run were not considered since no failures occurred for these modes. For each plant, as applicable depending on plant configurations, the fault models included contributions from unrecovered independent failures in injection header segments. Independent failures of the segments containing check valves were also considered, although recovery was not modeled since no failures were observed. Finally, the models included CCF contributions from failures to start of high-head pumps, failures to start of intermediate-head pumps, failures to run of high-head pumps, failures to run of intermediate-head pumps, and failures of the injection header segments. Recovery was included for the CCF contributors for the independent failure modes that identified failures. (The total failure probability used in the CCF estimation used the independent failure probability for the failure mode of interest.)

Alpha factors were used with the total failure probability estimates, as applicable, for the CCF contributors.

For the operational models, the failure modes were characterized with beta distributions, except for the FTR that used a gamma distribution, using raw data consisting of failure and demand counts. A plant-specific model was evaluated for each of the 72 plant units in the study.

- Plant-specific risk-based models, for each of the 72 plants. These were like the operational data models.

In the HPI system unreliability calculations, 3,000 simulations were evaluated in most IRRAS runs. The simulation outputs provided estimates of the mean value of the unreliability, together with uncertainty bounds and a standard deviation.

A-4. ESTIMATION OF ADDITIONAL DISTRIBUTIONS FOR TREND ANALYSIS

A-4.1 Frequency of Events

There were very few failures on unplanned demands, far too few to justify analysis for trends. However, there were enough of certain events to justify a trend analysis. These events are SI actuations (subdivided as automatic/manual and inadvertent/spurious), and reported failure events under all circumstances, unplanned demand or not. (A *failure event* is defined as an event in which one or more segments failed.) The frequency was defined as the expected number of events per “year.” The quantity “year” was reactor-calendar-year if the events could occur at any time, or it was reactor-critical-year if the events occurred almost entirely when the reactor was critical. Three analyses were performed.

First, each frequency was examined to determine whether significant differences exist among the years. The hypotheses of a simple Poisson distribution for the occurrences, with no differences between years, was tested using the Pearson chi-square test. The computed p-values are approximate since the expected cell counts were often small; however, they are useful for screening.

Second, cumulative plots were constructed, to see if any trends were gradual or sudden. The concern was that plants would have a sharply demarcated learning period at the beginning of life, after which they would quickly become dramatically better. Because the number of plants in the data period varies by age—there were few very young plants and few very old plants—the cumulative plot had to be modified as follows. As an example, consider a plot against age. Plant-specific plots were not useful, because no one plant had very many events. Instead, the plot was for the industry as a whole. Each event was plotted, with the plant age at the time of the event plotted on the horizontal axis. The cumulative plot jumped at each event occurrence. The height of the jump was 1/(exposure time for that age). For example, if the event occurred at a plant of age 2, the denominator was the number of reactor-years for reactors of age 2 during 1987–1997. The slope of the cumulative plot was an estimate of the frequency of events, and a change in the slope indicated a change in the event frequency. In the analysis described below the frequency was assumed to change exponentially, but this plot was used as a diagnostic, to help reveal whether the assumed gently changing rate was believable.

Finally, a loglinear model was used to quantify the trends, as described below.

For calculating a trend involving one explanatory variable, such as calendar year or plant low-power license year, the count in year i was assumed to be Poisson distributed with mean $\lambda_i t_{i.}$, where t_i is the total exposure time during year i, either total reactor-calendar-years or total reactor-critical-years. The frequency λ_i was assumed to depend on the year according to

$$\ln \lambda_i = a + bi \, .$$

The SAS procedure GENMOD[A-8] was used to estimate the parameters a and b by the method of maximum likelihood. The parameter b can be considered a slope parameter in the logarithmic scale.

Goodness of fit was evaluated by examining both the Pearson residuals and the deviance residuals (see Ref. A-9). The sum of the squared residuals should have a chi-squared distribution if the assumed model is correct. A too large observed sum of squares indicates underfit. A too small observed sum of squares indicates overfit. Disagreement between the Pearson and deviance sums of squares indicates that the data set is too small to allow an accurate assessment of the goodness of fit.

If the fit was adequate, the statistical significance of the trend was calculated using a large-sample approximation, under which the maximum likelihood estimator of the slope parameter is approximately normally distributed. For plotting purposes, a confidence band was constructed, as described in Ref. A-9. This is a band yielding 90% confidence that the band contains the true frequency at all times. Because it accounts for all times simultaneously, the confidence band is wider, by about 30%, than a 90% confidence interval for the frequency at any one particular time.

For modeling a frequency as a function of two explanatory variables, such as calendar year and low-power license date, the data were prepared as follows. The unplanned demands and the critical hours were counted for each time period, typically each calendar year. The count within each time period was assumed to be Poisson distributed.

Each record of the data file therefore contained five fields: the plant identifier, the calendar year, the low-power license year, the corresponding count of events, and the exposure time (either critical or calendar years for the plant). GENMOD was invoked with this data file. It fitted the model

$$\ln \lambda_{ij} = a + b_c i + b_l j \qquad \text{(A-1)}$$

for calendar year i and low-power license year j. The year i and age j are integers, and the parameters b_c and b_l quantify the effects of calendar year and low-power license year, respectively. In Section D-4 of Appendix D, λ_{ij} is graphed as a function of calendar year, i, for several selected values of low-power license year, j.

If the two goodness-of-fit measures, the Pearson sum of squares and the deviance sum of squares, did not agree on whether the fit was adequate, the data were pooled more. This was done by grouping the times into two-year bins instead of one-year bins. Calendar years were grouped as 1987, 1988-89, 1990-91, …, 1996-97, and low-power license years were grouped as 1966-67, 1968-69, …, 1996-97. This created fewer cells, and brought the two goodness-of-fit measures into agreement.

If the two goodness-of-fit measures agreed that the fit was inadequate, between-plant variation was added to the model. That is, the model was

$$\ln \lambda_{ij} = a + b_c i + b_l j + \upsilon \qquad \text{(A-2)}$$

where υ is a normally distributed random term, with each plant corresponding to a different value of υ. This model was evaluated using the SAS procedure GLIMMIX[A-10]. The estimates were reported as

$$\lambda_{ij} = \exp(a + b_c i + b_l j) \ .$$

In Section D-4 of Appendix D, this is graphed as a function of calendar year, *i*, for several selected values of low-power license year, *j*. The graph is described in the text as referring to the industry average, ignoring plant-specific variation, because the υ term is not shown in the graph.

The above discussion has considered both plant age at the time of an event and plant low-power license date. These two presentations are equivalent, for any event occurring on a known date. That is, let *i* and *j* be the event date and the low-power license date, and let *k* be the age of the plant at the time of the event, $k = i - j$. Then the model (A-1) can be rewritten as

$$\begin{aligned}\ln \lambda_{ij} &= a + b_c i + b_l j \\ &= a + b_c i + b_l (i - k) \\ &= a + (b_c + b_l) i - b_l k \ .\end{aligned}$$

This expresses $\ln\lambda$ as a function of event date and plant age instead of event date and low-power license date. The only difference in the two expressions occurs when dates and ages are rounded off, say to the nearest year. The rounding can cause slight differences in the numerical values. In this report, the model in terms of low-power license date was used, for two reasons. First, plant age at the time of the event is strongly correlated with event date, but low-power license date is not. This makes the significance of individual factors easier to interpret when low-power license date is used. Second, the computer programming happens to be simpler in terms of low-power license date.

A-4.2 Number of Failed Components per Failure Event

Some failure events involve multiple failed components. The failed components cannot be analyzed in the same way as failure events in the previous section. The reason is that the events were treated as independent in the previous section. The failed components are not independent; instead, they tend to come in bunches, because a single event can involve several failed components.

Therefore, the failed components were analyzed graphically as follows. The failure events were ordered by event date, and each event was then assigned a sequence number: 1, 2, 3, etc. A cumulative plot was constructed which jumps at the *i*th event by the number of components that failed. Thus, the horizontal axis counted the cumulative number of events, and the vertical axis counted the cumulative number of failed components. The slope showed the average number of failed components per event. This plot fell nearly on a straight line. Therefore, we concluded that the number of failed components per event did not seem to be affected by time, and that no further analysis was necessary.

A-5. REFERENCES

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Appendix B

HPI Operational Data, 1987–1997

Appendix B
HPI Operational Data, 1987–1997

In the subsections below, listings of the data used for the high-pressure safety injection (HPI) system reliability study are provided. First, the results of the data classification for failures are listed, then the results of the classification of the unplanned demands.

The HPI system operational data used in this report are based on LERs residing in the SCSS database. The SCSS database was searched for all records that explicitly identified an engineered safety feature (ESF) actuation or failure associated with the HPI system [high-head safety injection, intermediate-head safety injection, reactor/borated water storage tank (RWST/BWST)]for the years 1987 through 1997. To ensure as complete a data set as possible, the SCSS database was also searched for all safety injection actuations for plants that have an HPI system. These records would provide an additional source of HPI actuations because (1) the HPI system is demanded as a result of safety injection demand and (2) HPI may be required to start following a reactor trip as a result of a reactor coolant system overcooling experienced as part of the trip.

B-1. HPI INOPERABILITIES

The information encoded in the SCSS database, and included in this study, encompasses both actual and potential HPI failures during all plant operating conditions and testing. In this report, the term *inoperability* is used to describe any HPI component malfunction either actual or potential, except an ESF actuation, in which an LER was submitted in accordance with the requirements identified in 10 CFR 50.73. It is distinguished from the term *failure*, which is a subset of the inoperabilities for which a segment of the system was not able to perform its safety function. Details of the classification of the inoperability events is provided in Section A-2.1 of Appendix A.

Table B-1 provides the column headings and associated definitions of the information tabulated in Table B-2. Table B-2 is a listing of all the failure events that were included in the study. The events that were classified as failures include the applicable failure mode. A listing and description of the events used in the unreliability analysis are provided in Appendix C.

B-2. HPI UNPLANNED DEMANDS

To estimate reliability, information on the frequency and nature of HPI demands was needed. For the purposes of this study, an unplanned demand was defined as an event requiring either the system or segment of the system to perform its safety function as a result of a valid initiation signal that was not part of a pre-planned evolution. Unplanned demands usually were the result of a safety injection. Other plant conditions may have also resulted in an unplanned demand of HPI based on the plant-specific design of the HPI initiation circuit. These initiations of HPI were also included in the study if they resulted from a valid signal. Spurious signals or those inadvertent initiation signals that occurred during the performance of surveillance test were also classified as unplanned demands. For example, the shorting of test leads or blown fuses that resulted in a demand signal were counted as a valid demand. The spurious or inadvertent demands were counted due to the sparseness of the failure and demand data. Further, these types of actuations were considered as random tests on the response of the HPI system to a valid SI signal.

The LERs identified from the SCSS database search were reviewed to determine the nature and frequency of HPI unplanned demands. Specifically, each LER was reviewed to determine what segment(s) of the system were demanded. To determine which segment(s) of the system were demanded, the IPE and/or Final Safety Analysis Report (FSAR) for each plant were reviewed to determine the operating characteristics of the system for the specific plant. In addition to the operating characteristics, the plant-specific system schematic for HPI was also reviewed. The purpose of this review was to determine which segment(s) of the system were demanded when reviewing the full text of each LER.

The identification of the system operating characteristics and schematic for the system was necessary to capture the unplanned demand frequency for all the HPI segments because many LERs simply stated all systems functioned as designed. However, the full text of the LER would describe plant conditions that should have resulted in an unplanned demand of HPI based on the information provided in the IPE or FSAR. For example, the plant would state in the LER that reactor coolant pressure was less than 1500 psig. Based on the information provided in the IPE/FSAR for the particular plant, the condition would result in the pump pressure being greater than the reactor coolant system pressure. Hence, flow through the cold leg injection paths into the reactor coolant system. However, no explicit identification of the HPI cold leg injection was found in the LER. Therefore, based on the narrative of each LER and plant-specific knowledge concerning HPI initiation and operation, it was possible to determine a relatively accurate number of HPI unplanned demands throughout the industry, even though not every demand was explicitly identified in the LER. As a result of using this method for counting HPI segment demands, the reader/analyst should not compare the results used in this study to a simple SCSS database search for an HPI demand count. For more details on the counting of unplanned demands, see Section A-2.2.1 in Appendix A. Table B-3, which follows the table of HPI failures, provides the results of the search and categorization of HPI unplanned demands.

Table B-1. Column heading definitions and abbreviations used in Table B-2.

Column Heading	Definition
LER number	Self-explanatory. However, in some cases, the LER number listed is for the unplanned demand in which a failure was observed. It is not unusual for a plant to report the unplanned demand in one LER and mention that the system did not respond as designed. LER number XXX89001 and a followup LER (i.e., LER number XXX89003) provide the details of the failure and subsequent corrective actions. Also, the LER number may not match the docket number for a dual unit site. The LER may be under a Unit 1 number because the event affected both units; however, a failure may also be identified at Unit 2.
Event date	The event date is typically the date identified in Block 5 of the LER. In some cases, the Block 5 date may be different than the failure date because the system may have run for a period of time prior to the failure. In all cases, the event date is the date of the actual failure.
Segment affected	The segment of the system that the malfunction was assigned to: LOOP-INJ, cold leg injection path segment; INSTRMNT, instrumentation and control; CC-PUMP, high-head pump segment; SI-PUMP, intermediate-head pump segment; INJ-HDR, injection header segment; PUMP-SUCT, pump suction header segment (if applicable); RWST-SUCT, reactor water storage tank suction.
Cause	The cause of the inoperability: Design, system design; Maintenance, error associated with the performance of a maintenance activity; Hardware, a malfunction of a component that was installed properly; Gas binding, gas accumulation in the pump suction or in the pump casing; Support sys., the malfunction associate with a support system that ultimately prevented operation of a segment of HPI (an example would be a loss of a 4,160 Vac powerboard); Personnel, operators incorrectly operated the segment (an example would be that operators did not follow an established procedure to restore reactor coolant system pressure); Environment, the malfunction was the result of an environmental problem (an example would be an frozen recirculation line due to extreme cold weather).
Method of discovery	The method of discovery identifies how the inoperability was found. SI Demand, unplanned demand (ESF actuation); non-SI Demand, unplanned demand (actuation other than by ESF systems); Abnormal System Parameter, discovered through the normal course of routine plant operations (this category includes operators observing non-alarming parameters associated with operation of the system, etc.); Tour (this category includes operator walkdowns); Alarm (control room annunicators, alarms, etc. identifying a system anomaly); Design/Review, engineering design review; Test, periodic surveillance test.
Failure mode	The failure mode is risk-related information that is only provided for the events that are classified as failures. FTS, failure to start; FTR, failure to run; FTO, failure to operate; MOOS, maintenance-out-of-service. For the events classified as faults, the failure mode is N/A.
Recovered/ recoverable	True—If the segment failed as part of an unplanned demand and operators restored segment operation without replacing components. For a recoverable failure, the failure was judged to have been recoverable had operators attempted to restore the segment to operation. False—For all other methods of discovery or if recovery by plant operators was performed by replacing components.
Common dependency failure	True—If more than one segment failed as result of a single failure mechanism. As an example, two flow control valves fail to open on demand as a result of a blown fuse in a common control circuit. False—Independent failure.
Common cause failure	True—If more than one segment of the system exists in a failed state at the same time, or within a small time interval as result of a set of dependent failures resulting from a common mechanism. As an example, two flow control valves fail to open on demand as a result of improperly set torque switches for both valves. False—Independent failure.

Table B-2. High-pressure safety injection failure events.

Plant Name	LER Number	Event Date	Segment Affected	Number Affected	Cause	Method of Discovery	Failure Mode	Recovered/ Recoverable	Common Dependency Failure	Common Cause Failure
Arkansas Nuclear 1	31389004	1/20/89	Loop-Inj	1	Design	Non-SI Demand	FTO	No	No	No
Arkansas Nuclear 1	31391011	10/10/91	CC-Pump	1	Procedure	Test	FTR	No	No	Yes
Arkansas Nuclear 2	36892007	9/23/92	SI-Inj-Hdr	5	Personnel	Test	FTO	No	No	Yes
Beaver Valley 1	33491026	9/9/91	CC-Pump	1	Procedure	Troubleshooting	FTR	Yes	No	No
Beaver Valley 1	33491032	12/3/91	CC-Pump	2	Design	Design/Review	FTR	No	No	Yes
Beaver Valley 1	33497039	12/8/97	CC-Pump	1	Gas Binding	Design/Review	FTS	No	No	Yes
Beaver Valley 2	41296005	10/11/96	CC-Inj-Hdr	1	Hardware	Design/Review	FTO	No	No	Yes
			RWST-Suct	1						
Braidwood 1	45696009	7/29/96	SI-Inj-Hdr	1	Hardware	Test	FTO	No	No	No
Braidwood 2	45797005	11/6/97	SI-Inj-Hdr	1	Hardware	Test	FTO	No	No	No
Braidwood 2	45789003	3/22/89	CC-Pump	1	Personnel	non-SI Demand	FTR	No	No	No
Braidwood 2	45788001	3/5/88	SI-Pump	1	Personnel	Tour	FTR	No	No	No
Byron 2	45590007	9/28/90	Loop-Inj	1	Personnel	Test	FTO	No	No	No
Byron 2	45589001	2/11/89	Train	1	Support System	Abnormal Sys. Param.	FTO	No	No	No
Callaway 1	48391003	5/18/89	Loop-Inj	1	Personnel	Design/Review	FTO	No	No	No
Calvert Cliffs 1	31791009	11/26/91	SI-Pump	1	Hardware	Alarm	FTS	No	No	No
Catawba 1	41389027	11/20/89	CC-Pump	1	Hardware	non-SI Demand	FTR	No	No	No
Catawba 2	41496001	2/6/96	Train	1	Support System	SI Demand	FTO	No	No	No
Catawba 2	41489011	5/13/89	SI-Pump	1	Personnel	non-SI Demand	FTS	No	No	No
Catawba 2	41488026	7/13/88	CC-Pump	1	Hardware	non-SI Demand	FTR	No	No	No
Cook 1	31595011	9/12/95	CC-Pump	1	Personnel	Test	FTR	No	No	No
Cook 1	31589012	9/13/89	SI-Pump	2	Personnel	Design/Review	FTS	Yes	No	No
Crystal River 3	30294001	3/15/94	Loop-Inj	2	Personnel	Design/Review	FTO	Yes	No	No
Crystal River 3	30291018	12/8/91	System	1	Personnel	SI Demand	FTO	Yes	No	Yes
Davis-Besse 1	34689009	6/29/89	Loop-Inj	4	Hardware	Design/Review	FTO	Yes	No	No
Davis-Besse 1	34688015	7/2/88	Loop-Inj	1	Hardware	Troubleshooting	FTO	No	No	No
Diablo Canyon 1	27596001	2/1/96	CC-Pump	2	Procedure	Design/Review	FTR	No	No	No
Diablo-Canyon 1	27590009	3/22/90	CC-Inj-Hdr	8	Hardware	Troubleshooting	FTO	No	No	Yes
			SI-Inj-Hdr	2						

Table B-2. (continued).

Plant Name	LER Number	Event Date	Segment Affected	Number Affected	Cause	Method of Discovery	Failure Mode	Recovered/ Recoverable	Common Dependency Failure	Common Cause Failure
Diablo Canyon 1	27592010	6/2/92	SI-Pump	1	Personnel	Test	FTS	No	No	No
Farley 2	36487010	12/9/87	Loop-Inj	1	Hardware	Test	FTO	No	No	No
Ft. Calhoun 1	28588002	1/25/88	SI-Inj-Hdr	1	Hardware	Design/Review	FTO	No	No	No
Ginna 1	24494011	9/17/94	Train	1	Hardware	Alarm	FTO	Yes	No	No
Ginna 1	24494009	8/9/94	SI-Pump	3	Hardware	Test	FTR	No	No	Yes
Ginna 1	24487008	12/23/87	SI-Pump	1	Design	Test	FTS	No	No	No
Ginna 1	24489003	5/18/89	Train	1	Hardware	SI Demand	FTO	No	No	No
Ginna 1	24494008	6/13/94	SI-Pump	1	Hardware	Test	FTR	No	No	No
Ginna 1	24490017	12/12/90	System	1	Procedure	Abnormal Sys. Param.	FTO	Yes	No	No
Haddam Neck 1	21390013	8/6/90	Pump-Suct	2	Personnel	Design/Review	FTO	No	No	No
Haddam Neck 1	21390012	8/2/90	CC-Pump	1	Gas Binding	non-SI Demand	FTS	No	No	No
Haddam Neck 1	21387018	11/20/87	CC-Inj-Hdr	2	Personnel	Design/Review	FTO	No	No	No
			Loop-Inj	4						
Haddam Neck 1	21394013	5/5/94	SI-Pump	1	Hardware	Test	FTR	No	No	No
Haddam Neck 1	21395020	11/8/95	CC-Pump	1	Hardware	Tour	FTR	No	No	No
Indian Point 2	24797024	10/31/97	SI-Pump	1	Hardware	Test	FTS	No	No	No
Indian Point 2	24788020	12/11/88	RWST-Suct	1	Design	Alarm	FTO	No	No	Yes
Indian Point 3	28691011	10/15/91	Train	1	Hardware	Alarm	FTO	No	No	No
Indian Point 3	28692003	2/9/92	Train	1	Hardware	Alarm	FTO	No	No	No
Kewaunee 1	30592013	5/14/92	Train	1	Hardware	Troubleshooting	FTO	No	No	No
Kewaunee 1	30595006	4/20/95	SI-Pump	1	Hardware	Test	FTR	No	No	No
Maine Yankee 1	30996020	8/17/96	CC-Pump	1	Personnel	Test	FTS	Yes	No	No
McGuire 1	36988025	8/29/88	Pump-Suct	1	Personnel	Design/Review	FTO	Yes	No	No
McGuire 1	36988020	8/12/88	SI-Pump	1	Hardware	Test	FTR	No	No	No
McGuire 2	37090009	9/7/90	CC-Inj-Hdr	1	Hardware	Test	FTO	No	No	No
			Loop-Inj	1						
Millstone 2	33696012	2/28/96	Loop-Inj	1	Hardware	Test	FTO	No	No	No
Millstone 3	42392026	11/3/92	SI-Pump	2	Procedure	Design/Review	FTR	No	No	No
Millstone 3	42390017	5/18/90	SI-Inj-Hdr	1	Personnel	Tour	FTO	No	No	No

Table B-2. (continued).

Plant Name	LER Number	Event Date	Segment Affected	Number Affected	Cause	Method of Discovery	Failure Mode	Recovered/ Recoverable	Common Dependency Failure	Common Cause Failure
Millstone 3	42391011	4/10/91	SI-Inj-Hdr	1	Design	Test	FTO	No	No	No
Millstone 3	42390020	6/14/90	SI-Pump	2	Personnel	Design/Review	FTR	No	No	No
North Anna 1	33896006	10/3/96	CC-Pump	1	Hardware	Abnormal Sys. Param.	FTR	No	No	No
North Anna 1	33890011	11/1/90	CC-Pump	1	Personnel	Alarm	FTR	Yes	No	No
North Anna 1	33893009	3/20/93	Loop-Inj	2	Procedure	Test	FTO	Yes	No	No
North Anna 2	33990008	10/20/90	Loop-Inj	2	Procedure	Test	FTO	No	No	No
North Anna 2	33987002	3/23/87	CC-Pump	1	Hardware	non-SI Demand	FTR	No	No	No
North Anna 2	33992010	4/13/92	Loop-Inj	2	Procedure	Test	FTO	Yes	No	No
Oconee 1	26988014	11/14/88	CC-Pump	1	Personnel	Design/Review	FTS	Yes	No	No
Oconee 2	27097001	4/21/97	Loop-Inj	1	Design	Alarm	FTO	No	No	No
Oconee 3	28797003	5/3/97	CC-Pump	2	Hardware	Abnormal Sys. Param.	FTR	No	No	Yes
Oconee 3	28787006	4/10/87	RWST-Suct	2	Personnel	Design/Review	FTO	Yes	No	Yes
Palisades 1	25597004	2/21/97	SI-Pump	1	Hardware	non-SI Demand	FTS	No	No	No
Palisades 1	25596010	7/17/96	SI-Pump	1	Hardware	non-SI Demand	FTS	No	No	No
Palisades 1	25589010	6/2/89	SI-Pump	1	Hardware	non-SI Demand	FTS	No	No	No
Palo Verde 1	52888004	2/29/88	SI-Pump	2	Procedure	Tour	FTS	No	No	Yes
Palo Verde 1	52892005	3/18/92	Loop-Inj	1	Personnel	Tour	FTO	No	No	No
Palo Verde 2	52988005	2/21/88	SI-Inj-Hdr	1	Hardware	SI Demand	FTO	No	No	No
Palo Verde 2	52994005	10/19/94	SI-Inj-Hdr	1	Hardware	Test	FTO	No	No	No
Point Beach 2	30192003	9/18/92	SI-Pump	1	Personnel	Test	FTS	No	No	No
Prairie Island 1	28287009	6/18/87	SI-Pump	1	Personnel	Test	FTS	No	No	No
Robinson 2	26192018	8/24/92	SI-Pump	2	Personnel	Test	FTR	No	No	Yes
Robinson 2	26192014	7/9/92	SI-Pump	1	Hardware	non-SI-Demand	FTS	No	No	No
Robinson 2	26187015	6/12/87	SI-Inj-Hdr	2	Personnel	Abnormal Sys. Param.	FTO	Yes	No	Yes
Robinson 2	26192013	7/9/92	SI-Pump	1	Personnel	Test	FTR	No	No	No
Salem 1	27290022	7/22/90	SI-Inj-Hdr	1	Hardware	Troubleshooting	FTO	No	No	No
Salem 1	27289033	12/1/89	CC-Pump	1	Hardware	Tour	FTR	No	No	No
Salem 1	27287006	5/25/87	CC-Pump	1	Hardware	Tour	FTS	No	No	No
Salem 2	31190005	1/17/90	CC-Inj-Hdr	1	Hardware	Tour	FTO	No	No	No

Table B-2. (continued).

Plant Name	LER Number	Event Date	Segment Affected	Number Affected	Cause	Method of Discovery	Failure Mode	Recovered/ Recoverable	Common Dependency Failure	Common Cause Failure
Salem 2	31188012	6/18/88	CC-Pump	2	Hardware	Test	FTS	No	No	No
Salem 2	31190042	12/20/90	SI-Pump	2	Hardware	Tour	FTR	No	No	No
Salem 2	31194010	9/22/94	CC-Pump	1	Procedure	Abnormal Sys. Param.	FTR	No	No	No
San Onofre 3	36287013	6/24/87	SI-Pump	2	Hardware	Test	FTR	Yes	No	No
Sequoyah 1	32792014	8/10/92	SI-Pump	1	Hardware	Test	FTS	Yes	No	No
Sequoyah 1	32789001	1/3/89	RWST-Suct	1	Design	Test	FTO	Yes	No	No
Sequoyah 1	32791003	2/18/91	CC-Pump	1	Hardware	Abnormal Sys. Param.	FTR	No	No	No
Sequoyah 2	32888010	3/9/88	CC-Pump	1	Personnel	Tour	FTS	Yes	No	No
Sequoyah 2	32890012	8/22/90	CC-Pump	1	Gas Binding	Test	FTR	No	No	Yes
Sequoyah 2	32894002	1/8/94	CC-Pump	1	Gas Binding	non-SI Demand	FTR	No	No	No
Sequoyah 2	32894007	9/23/94	CC-Pump	1	Personnel	Test	FTR	Yes	No	No
Sequoyah 2	32888005	2/12/88	CC-Pump	2	Maintenance	Tour	FTR	No	No	Yes
Shearon Harris 1	40093005	4/28/93	CC-Pump	1	Hardware	Design/Review	FTS	No	No	No
Shearon Harris 1	40091008	4/3/91	CC-Pump	3	Design	Test	FTR	No	No	Yes
Shearon Harris 1	40095008	9/2/95	CC-Pump	1	Hardware	Design/Review	FTS	No	No	No
Shearon Harris 1	40087008	2/27/87	RWST-Suct	1	Hardware	non-SI Demand	FTO	No	No	No
South Texas 2	49991010	12/24/91	System	1	Design	SI Demand	FTO	Yes	No	No
Surry 1	28088020	6/28/88	CC-Pump	2	Support System	Abnormal Sys. Param.	FTR	No	No	No
Surry 1	28088036	9/12/88	CC-Pump	2	Support System	Abnormal Sys. Param.	FTR	No	No	No
Surry 1	28091002	3/26/91	CC-Pump	1	Personnel	Abnormal Sys. Param.	FTR	No	No	No
Surry 1	28087033	11/24/87	CC-Pump	2	Support System	Abnormal Sys. Param.	FTR	No	No	No
Surry 2	28187001	3/12/87	CC-Pump	1	Personnel	non-SI Demand	FTR	Yes	No	No
Surry 2	28192001	1/30/92	CC-Pump	1	Hardware	non-SI Demand	FTR	No	No	No
Surry 2	28192002	2/27/92	CC-Pump	2	Personnel	Design/Review	FTS	Yes	No	No
Surry 2	28188004	3/27/88	CC-Pump	1	Hardware	SI Demand	FTR	No	No	No
Turkey Point 3	25088018	8/22/88	RWST-Suct	1	Procedure	Test	FTO	Yes	No	No
Turkey Point 3	25094002	5/5/94	SI-Pump	1	Hardware	SI Demand	FTS	No	No	No
Turkey Point 3	25094004	11/3/94	SI-Pump	2	Personnel	Tour	FTS	Yes	No	No
Turkey Point 3	25094005	11/3/94	SI-Pump	1	Design	Test	FTS	Yes	Yes	No

Table B-2. (continued).

Plant Name	LER Number	Event Date	Segment Affected	Number Affected	Cause	Method of Discovery	Failure Mode	Recovered/ Recoverable	Common Dependency Failure	Common Cause Failure
Vogtle 1	42496010	11/1/96	SI-Pump	1	Procedure	Tour	FTR	No	No	Yes
Vogtle 1	42492004	5/14/92	Loop-Inj	1	Hardware	Alarm	FTO	No	No	No
Vogtle 1	42487045	7/2/87	CC-Pump	1	Personnel	Alarm	FTR	No	No	No
Vogtle 2	42591008	6/25/91	CC-Pump	2	Procedure	Design/Review	FTR	Yes	No	No
Wolf Creek 1	48290025	12/23/90	SI-Pump	2	Hardware	Alarm	FTR	No	No	Yes
Wolf Creek 1	48289019	9/19/89	CC-Pump	1	Hardware	Test	FTR	No	No	No
Zion 1	29594001	2/19/94	Loop-Inj	4	Procedure	Test	FTO	No	No	No
Zion 1	29594004	3/26/94	Pump-Suct	1	Personnel	Test	FTO	No	No	No
Zion 1	29596007	3/8/96	SI-Pump	2	Environment	Abnormal Sys. Param.	FTR	No	No	Yes
Zion 1	29592018	10/7/92	Loop-Inj	1	Personnel	Tour	FTO	Yes	No	No
Zion 2	30491001	1/4/91	SI-Pump	2	Environment	Test	FTR	No	No	Yes
Zion 2	30492004	7/15/92	SI-Pump	2	Environment	Test	FTR	No	No	No
Zion 2	30496009	10/28/96	SI-Pump	1	Hardware	Test	FTR	No	No	No

Table B-3. High-pressure safety injection unplanned demands.

Plant Name	LER Number	Event Date	Train Act	RWST-Suction	Segment Demanded SI-Pump	CC-Pump	SI-Inj-Hdr	CC-Inj-Hdr	Loop-Inj
	39097008	3/6/97							
Arkansas Nuclear Unit 1	31396005	5/19/96		1		1		2	2
Arkansas Nuclear Unit 1	31394002	4/11/94		1		1		2	2
Arkansas Nuclear Unit 1	31390017	12/7/90							
Arkansas Nuclear Unit 1	31389002	1/20/89		1		1		2	2
Arkansas Nuclear Unit 2	36888007	4/23/88	2	1					
Arkansas Nuclear Unit 2	36888003	3/10/88	2						
Arkansas Nuclear Unit 2	36888011	8/1/88		1	1		2		1
Arkansas Nuclear Unit 2	36888015	8/1/88							
Arkansas Nuclear Unit 2	36892006	9/9/92	2				2		
Arkansas Nuclear Unit 2	36888020	12/1/88	2	1	2		4		
Arkansas Nuclear Unit 2	36889012	6/26/89		3	3		6		3
Arkansas Nuclear Unit 2	36889018	10/17/89	2						
Beaver Valley Unit 1	33490016	10/24/90							
Beaver Valley Unit 1	33489007	5/18/89	2	1		2		2	9
Beaver Valley Unit 1	33488007	6/7/88	2	1	2		8		4
Beaver Valley Unit 1	33495003	2/19/95	2						
Beaver Valley Unit 1	33489015	12/13/89	1						
Beaver Valley Unit 1	33491010	4/5/91							
Beaver Valley Unit 1	33493013	10/12/93							
Beaver Valley Unit 2	41294004	3/15/94	1						
Beaver Valley Unit 2	41293002	1/30/93	2	1		2		6	4
Beaver Valley Unit 2	41289005	3/22/89	2						
Beaver Valley Unit 2	41292006	5/1/92	2	1		2		6	4
Beaver Valley Unit 2	41287002	6/29/87	1					1	
Beaver Valley Unit 2	41287011	7/30/87	2	1		2		6	4
Beaver Valley Unit 2	41288004	2/1/88		1		1			
Beaver Valley Unit 2	41287024	9/29/87	2	1		2		6	4

Table B-3. (continued).

					Segment Demanded				
Plant Name	LER Number	Event Date	Train Act	RWST-Suction	SI-Pump	CC-Pump	SI-Inj-Hdr	CC-Inj-Hdr	Loop-Inj
Braidwood Unit 1	45687062	12/11/87	2						
Braidwood Unit 1	45689016	12/1/89							
Braidwood Unit 1	45690018	9/29/90	2	2	2	2	2	2	12
Braidwood Unit 1	45692013	10/23/92	1	1		1		1	4
Braidwood Unit 1	45689002	4/16/89	2	1	2	2	1	1	4
Braidwood Unit 1	45689014	10/30/89	1	1					
Braidwood Unit 1	45688002	1/25/88	2	1		1		1	4
Braidwood Unit 2	45793002	4/14/93							
Braidwood Unit 2	45790003	4/5/90	1	1				1	
Braidwood Unit 2	45790002	3/18/90		1		1		1	
Byron Unit 1	45487004	2/25/87	2					1	4
Byron Unit 1	45491004	10/16/91	1	1					
Byron Unit 1	45487019	8/12/87	2	1	2	2	1	1	8
Byron Unit 1	45487009	4/8/87	2						
Byron Unit 2	45587020	12/2/87							
Byron Unit 2	45587016	8/31/87	1	1	1	1	1	1	8
Byron Unit 2	45589001	2/11/89	2	1	1	2	1	1	8
Byron Unit 2	45590001	1/18/90	2	1	2	2	1	1	8
Byron Unit 2	45590006	9/3/90	1						
Byron Unit 2	45593004	9/5/93	1	1		1	1	1	4
Callaway Unit 1	48389005	5/18/89	2	1	1	1	1	1	8
Callaway Unit 1	48395005	8/16/95							
Callaway Unit 1	48388004	12/13/88	2	1	2	2	1	1	4
Calvert Cliffs Unit 1	31788002	5/2/88	6						
Calvert Cliffs Unit 1	31789003	3/19/89	2						
Calvert Cliffs Unit 1	31790003	3/8/90	2						
Calvert Cliffs Unit 1	31790023	8/2/90	4						
Calvert Cliffs Unit 1	31797005	5/27/95	2	1	2		8		
Calvert Cliffs Unit 1	31789004	3/20/89	2				4		

Table B-3. (continued).

Plant Name	LER Number	Event Date	Train Act	RWST-Suction	Segment Demanded: SI-Pump	Segment Demanded: CC-Pump	Segment Demanded: SI-Inj-Hdr	CC-Inj-Hdr	Loop-Inj
Calvert Cliffs Unit 2	31891001	3/12/91							
Calvert Cliffs Unit 2	31891002	3/27/91	1						
Catawba Unit 1	41389008	3/5/89	2	1	2	2	1	1	4
Catawba Unit 1	41388007	1/23/88	2	1	2	2	1	1	4
Catawba Unit 1	41397011	12/30/97	1	1		1		1	4
Catawba Unit 2	41496001	2/6/96	2	1	1	1	1	1	4
Catawba Unit 2	41489004	2/21/89	2	1	2	2	1	1	4
Catawba Unit 2	41489003	2/21/89		1	2	2		1	4
Catawba Unit 2	41496007	12/16/96							
Catawba Unit 2	41488003	2/9/88	2	1		1		1	4
Catawba Unit 2	41491011	9/13/91							
Comanche Unit 1	44596001	1/17/96	2	1	2	2		1	4
Comanche Unit 1	44593003	2/26/93							
Comanche Unit 1	44590004	3/12/90	1	1	1	1	1	1	8
Comanche Unit 1	44591022	9/4/91		1		1			
Comanche Unit 1	44590037	11/5/90		1		1			
Comanche Unit 1	44590021	7/30/90	2	1	2	2		1	4
Comanche Unit 1	44590020	7/26/90	2	1	2	2		1	4
Comanche Unit 1	44592016	6/23/92		1		2			
Cook Unit 2	31687011	10/2/87	1						
Crystal River Unit 3	30291018	12/8/91	2	1		3		2	4
Crystal River Unit 3	30293009	9/18/93							1
Crystal River Unit 3	30287030	11/20/87	1						
Crystal River Unit 3	30287022	11/6/87	1						
Crystal River Unit 3	30288021	10/14/88	2						
Crystal River Unit 3	30287011	7/10/87		1		1		1	1
Davis-besse Unit 1	34690010	5/18/90							
Diablo Canyon Unit 1	27591009	5/17/91	2	1	2	2	1	1	8
Diablo Canyon Unit 1	27590017	12/24/90	2	1	2	2	1	1	8

Table B-3. (continued).

Plant Name	LER Number	Event Date	Train Act	RWST-Suction	Segment Demanded: SI-Pump	CC-Pump	SI-Inj-Hdr	CC-Inj-Hdr	Loop-Inj
Diablo Canyon Unit 1	27591005	3/23/91	2	1				1	
Diablo Canyon Unit 1	27589009	10/6/89	2	1	2	2	1	1	8
Diablo Canyon Unit 2	32397005	10/24/97	2	1	2	2	1	1	8
Diablo Canyon Unit 2	32387003	3/21/87	2	1	2	2	1	1	8
Diablo Canyon Unit 2	32387004	4/3/87	2	1	2	2	1	1	8
Diablo Canyon Unit 2	32387016	7/14/87	2	1	2	2	1	1	8
Diablo Canyon Unit 2	32388008	7/17/88	2	1	2	2	1	1	8
Diablo Canyon Unit 2	32391007	10/6/91	4						
Farley Unit 1	34892003	7/28/92							
Farley Unit 1	34895004	4/26/95							
Farley Unit 1	34889006	11/12/89	2	1		2		2	3
Farley Unit 1	34888024	12/6/88							
Farley Unit 1	34896003	6/2/96							
Farley Unit 2	36492003	5/2/92	2	1					
Farley Unit 2	36489005	4/29/89	1	1		1			
Farley Unit 2	36493001	2/5/93	1	1					
Farley Unit 2	36490004	11/16/90	1	1		1			
Ft. Calhoun Unit 1	28588038	12/31/88	1						
Ft. Calhoun Unit 1	28594001	2/11/94	2	1	3		12		4
Ft. Calhoun Unit 1	28590011	4/2/90	2						
Ft. Calhoun Unit 1	28592023	7/3/92	2	1	3		12		4
Ft. Calhoun Unit 1	28593015	11/3/93							
Ft. Calhoun Unit 1	28590008	3/6/90	1						
Ft. Calhoun Unit 1	28587015	5/20/87	1						
Ft. Calhoun Unit 1	28587012	4/13/87	2						
Ft. Calhoun Unit 1	28587011	4/28/87	2						
Ft. Calhoun Unit 1	28593009	5/24/93							
Ft. Calhoun Unit 1	28587006	3/27/87	2						
Ginna Unit 1	24497005	10/31/97	2						

Table B-3. (continued).

Plant Name	LER Number	Event Date	Train Act	RWST-Suction	Segment Demanded				
					SI-Pump	CC-Pump	SI-Inj-Hdr	CC-Inj-Hdr	Loop-Inj
Ginna Unit 1	24489003	5/18/89	2	1	1				
Ginna Unit 1	24490006	5/5/90	2	1	3				
Ginna Unit 1	24495003	4/7/95	2						
Ginna Unit 1	24488005	6/1/88	2	1	3		2		
Haddam Neck Unit 1	21395016	7/27/95	2	1	2	2			4
Haddam Neck Unit 1	21390005	6/6/90							
Haddam Neck Unit 1	21393011	7/6/93							
Indian Point Unit 2	24788001	1/17/88	2	1	3				
Indian Point Unit 2	24797010	5/1/97	2	1	3		6		4
Indian Point Unit 2	24792002	1/27/92	2	1	3		6		4
Indian Point Unit 2	24797009	5/2/97	2	1	3		6		4
Indian Point Unit 3	28689001	2/4/89	2				1		
Indian Point Unit 3	28695009	4/29/95	2				1		
Indian Point Unit 3	28687002	2/11/87	2	1	3		1		
Indian Point Unit 3	28687004	4/17/87	2	1	3		1		
Indian Point Unit 3	28687010	9/3/87	2	1	3		1		
Kewaunee Unit 1	30588002	3/28/88	2	1	2		0		
Maine Yankee Unit 1	30988011	12/22/88	2	1		2		10	3
Maine Yankee Unit 1	30990002	4/14/90	2	1				10	3
Maine Yankee Unit 1	30992002	2/25/92	2						
McGuire Unit 1	36991015	10/13/91	1						
McGuire Unit 1	36988005	3/23/88	1	1	1	1		1	4
McGuire Unit 1	36987017	8/16/87	2	1	2	2		1	4
McGuire Unit 1	36987012	7/9/87		1	1				
McGuire Unit 1	36991001	2/11/91	2	1	2	2	1	1	8
McGuire Unit 1	36989004	3/7/89		1		2		1	4
McGuire Unit 2	37097001	5/27/97		1	1	1			
McGuire Unit 2	37093003	3/22/93				2			
McGuire Unit 2	37093008	12/27/93	2	1	2	2	1	1	8

Table B-3. (continued).

Plant Name	LER Number	Event Date	Train Act	RWST-Suction	Segment Demanded SI-Pump	CC-Pump	SI-Inj-Hdr	CC-Inj-Hdr	Loop-Inj
Millstone Unit 2	33689005	3/30/89							
Millstone Unit 2	33690015	9/19/90	2						
Millstone Unit 2	33694010	5/13/94	1						
Millstone Unit 2	33694023	7/25/94							
Millstone Unit 3	42390002	1/9/90	1	1	1	1			
Millstone Unit 3	42389005	2/17/89	1	1		1		1	4
Millstone Unit 3	42389034	12/11/89	1	1	1	1			
Millstone Unit 3	42389033	12/5/89	2	1	2	2	1	1	4
Millstone Unit 3	42395007	4/16/95	1						
Millstone Unit 3	42388001	1/5/88	1						
Millstone Unit 3	42387016	3/25/87	1	1		1		1	4
North Anna Unit 1	33887017	7/15/87	2	1		2			3
North Anna Unit 1	33889006	3/23/89							
North Anna Unit 1	33891015	7/14/91				1			
North Anna Unit 1	33891023	12/27/91							
North Anna Unit 1	33891017	8/8/91	2	1		2		1	3
North Anna Unit 2	33991009	9/20/91	2	1		2		1	3
North Anna Unit 2	33988002	7/26/88				1			
North Anna Unit 2	33987014	10/22/87							
North Anna Unit 2	33992007	8/6/92	2	1		2	1		3
North Anna Unit 2	33987013	10/26/87	2						
Oconee Unit 1	26991006	5/16/91		1		1		1	2
Oconee Unit 1	26993010	11/3/93		1		1		1	2
Oconee Unit 1	26990007	5/16/90	2						
Oconee Unit 1	26989002	1/3/89		2		2		2	4
Oconee Unit 1	26989001	1/2/89	1	1		1	1		2
Oconee Unit 1	26994002	2/26/94		1		1		1	2
Oconee Unit 2	27094002	4/6/94		1		1		1	2
Oconee Unit 2	27093007	10/24/93		1		1		1	2

Table B-3. (continued).

Plant Name	LER Number	Event Date	Train Act	RWST-Suction	Segment Demanded: SI-Pump	Segment Demanded: CC-Pump	Segment Demanded: SI-Inj-Hdr	CC-Inj-Hdr	Loop-Inj
Oconee Unit 2	27092004	10/19/92		1		3		2	4
Oconee Unit 2	27089003	2/5/89		1		1		1	2
Oconee Unit 2	27089002	2/3/89		1		1		1	2
Oconee Unit 2	27087002	3/26/87		1		1		1	2
Oconee Unit 2	27087001	1/18/87		1		1		1	2
Oconee Unit 2	27095002	4/14/95		1		1		1	2
Oconee Unit 3	28789004	8/18/89		1		1		1	2
Oconee Unit 3	28789005	11/14/89	2						
Oconee Unit 3	28791007	7/3/91		1		1		1	2
Oconee Unit 3	28790003	11/13/90		1		1		1	2
Oconee Unit 3	28789002	3/6/89		1		1		1	2
Oconee Unit 3	28790002	3/7/90		1		1		1	2
Palisades Unit 1	25589025	11/21/89	2	1	2		2		8
Palisades Unit 1	25595001	3/2/95	1	1	1		5		
Palisades Unit 1	25587032	9/10/87							
Palisades Unit 1	25595005	7/21/95	2						
Palisades Unit 1	25592031	4/2/92							
Palo Verde Unit 1	52892007	5/6/92	2						
Palo Verde Unit 1	52891004	3/20/91							
Palo Verde Unit 1	52891010	10/27/91	2	1	2		8		4
Palo Verde Unit 2	52989003	2/16/89	2	1	2		8		4
Palo Verde Unit 2	52997005	9/23/97	2						
Palo Verde Unit 2	52992006	11/13/92	2	1	2		8		4
Palo Verde Unit 2	52993001	3/14/93	2	1	2		8		4
Palo Verde Unit 2	52987010	6/4/87	2	1	2		8		4
Palo Verde Unit 2	52989009	7/12/89	2	1	2		8		4
Palo Verde Unit 2	52991008	12/23/91		1	1		4		4
Palo Verde Unit 2	52988005	2/21/88	2				8		
Palo Verde Unit 3	52891010	10/27/91	2	1	2				

Table B-3. (continued).

Plant Name	LER Number	Event Date	Train Act	RWST-Suction	Segment Demanded				
					SI-Pump	CC-Pump	SI-Inj-Hdr	CC-Inj-Hdr	Loop-Inj
Palo Verde Unit 3	53089001	3/3/89	2	1	2		8		4
Palo Verde Unit 3	53093001	2/4/93	2	1	2		8		4
Palo Verde Unit 3	53091003	6/19/91							
Point Beach Unit 1	26687005	11/21/87	2	2	2		4		2
Point Beach Unit 1	26691008	6/29/91	2	2	2		4		
Point Beach Unit 1	26696001	4/5/96	1						
Point Beach Unit 2	30188001	4/7/88	2	2	4		8		
Point Beach Unit 2	30189007	10/27/89	2						
Point Beach Unit 2	30189010	10/8/89							
Point Beach Unit 2	30195004	10/26/95							
Prairie Island Unit 1	28294001	3/1/94							
Prairie Island Unit 1	28287004	3/30/87	1	1	1		1		
Rancho Seco Unit 1	31289004	3/28/89							
Rancho Seco Unit 1	31288018	12/9/88							
Robinson Unit 2	26189004	2/27/89	2	1	3		3		
Robinson Unit 2	26188026	11/14/88	2						
Robinson Unit 2	26188005	2/13/88	2						
Robinson Unit 2	26192017	8/22/92	2	1	3		3		3
Salem Unit 2	31190037	9/22/90	1		1	1			
Salem Unit 2	31188014	6/22/88	2	1	2	2	1	1	8
Salem Unit 2	31190017	5/1/90	1						
Salem Unit 2	31191012	8/26/91			1	1			
Salem Unit 2	31192001	1/4/92							
Salem Unit 2	31193006	4/15/93	1						
Salem Unit 2	31193014	12/28/93							
Salem Unit 2	31189005	3/12/89	2	1	2	2	1	1	8
Salem1	27294007	4/7/94	4	2	2	2	2	2	8
Salem1	27289024	6/9/89	2	1	2	2	1	1	4
Salem1	27291027	8/15/91	2	1	1		0		0

Table B-3. (continued).

Plant Name	LER Number	Event Date	Train Act	RWST-Suction	Segment Demanded			CC-Inj-Hdr	Loop-Inj
					SI-Pump	CC-Pump	SI-Inj-Hdr		
Salem1	27292009	4/6/92							
San Onofre Unit 2	36190014	11/20/90	2	1	2		8		
San Onofre Unit 3	36289001	1/6/89	2	1	2		8		
San Onofre Unit 3	36288002	12/19/88	2	1	2		8		
San Onofre Unit 3	36287011	6/21/87	2	1	2		8		4
Seabrook Unit 1	44391012	9/27/91	1						
Seabrook Unit 1	44387015	8/13/87	1	1		1		1	4
Seabrook Unit 1	44387012	4/16/87	1	1		1		1	4
Seabrook Unit 1	44387009	3/10/87	2	1	2	2		1	4
Seabrook Unit 1	44394001	1/25/94	2	1	2	2		1	4
Sequoyah Unit 1	32788016	3/24/88	2						
Sequoyah Unit 1	32792011	4/29/92	2	1	2	2	1	1	8
Sequoyah Unit 1	32792017	8/31/92	1						
Sequoyah Unit 2	32894003	1/10/94							
Sequoyah Unit 2	32892011	8/21/92	2	1	2	2	1	1	8
Shearon Harris Unit 1	40087045	7/16/87							
Shearon Harris Unit 1	40097014	5/14/97	2	1				4	3
Shearon Harris Unit 1	40095011	11/5/95	1	1		2		4	3
Shearon Harris Unit 1	40095009	10/5/95	1						
Shearon Harris Unit 1	40088029	9/15/88							
Shearon Harris Unit 1	40087062	11/7/87	2	1		2		4	3
South Texas Unit 1	49888018	12/2/88	3	1	3				3
South Texas Unit 1	49895009	8/29/95							
South Texas Unit 1	49894011	3/10/94	3						3
South Texas Unit 1	49891002	1/26/91	3						
South Texas Unit 1	49888059	10/6/88		1	1				1
South Texas Unit 1	49888049	8/26/88	3	1	3				
South Texas Unit 1	49888022	2/28/88	3	1	3				
South Texas Unit 1	49888026	3/30/88	3	1	3				

Table B-3. (continued).

Plant Name	LER Number	Event Date	Train Act	RWST-Suction	Segment Demanded				
					SI-Pump	CC-Pump	SI-Inj-Hdr	CC-Inj-Hdr	Loop-Inj
South Texas Unit 2	49991010	12/24/91	6	2	6				
South Texas Unit 2	49990001	1/8/90	3						
South Texas Unit 2	49989011	4/10/89	3	1	3				
St. Lucie Unit 1	33591006	9/18/91							
St. Lucie Unit 1	33593001	1/8/93					2		
St. Lucie Unit 1	33594010	11/24/94	2						
St. Lucie Unit 1	33587010	4/14/87	2	1	2		8		
St. Lucie Unit 1	33588001	2/5/88							
St. Lucie Unit 1	33594009	11/22/94	2						
St. Lucie Unit 1	33596008	7/3/96	1						
St. Lucie Unit 1	33587003	2/12/87	2						
St. Lucie Unit 2	38990004	11/9/90	2						
St. Lucie Unit 2	38992003	5/26/92							
St. Lucie Unit 2	38993003	2/1/93							
Summer Unit 1	39588006	5/12/88	2	1		2		7	3
Summer Unit 1	39588013	12/11/88	1	1		2		4	3
Surry Unit 1	28093001	1/8/93	1	1		1		1	3
Surry Unit 1	28088029	8/15/88	2	1		1		1	3
Surry Unit 1	28090018	12/3/90	1	1				1	
Surry Unit 1	28089006	2/8/89	1	1				1	
Surry Unit 1	28087023	9/1/87				1		1	3
Surry Unit 1	28087024	9/20/87	2	1		2		1	3
Surry Unit 1	28097008	10/11/97	1					1	
Surry Unit 2	28191007	8/2/91	1	1		1		1	3
Surry Unit 2	28189004	8/18/89							
Surry Unit 2	28187001	3/12/87							
Surry Unit 2	28188004	3/27/88	2	1		1		1	3
Surry Unit 2	28188010	5/16/88	1	1		1		1	3
Three Mile Island Unit 1	28990001	1/7/90							

Table B-3. (continued).

Plant Name	LER Number	Event Date	Train Act	RWST-Suction	Segment Demanded: SI-Pump	CC-Pump	SI-Inj-Hdr	CC-Inj-Hdr	Loop-Inj
Three Mile Island Unit 1	28989001	10/30/89	2	1		1		2	4
Three Mile Island Unit 1	28990006	7/2/90	1	1		1		2	4
Trojan Unit 1	34492008	2/23/92							
Trojan Unit 1	34488022	7/4/88							
Turkey Point Unit 3	25096007	3/29/96	2	2	3				
Turkey Point Unit 3	25087016	5/27/87	2						
Turkey Point Unit 3	25087021	7/1/87	2	2	3				
Turkey Point Unit 3	25087023	9/13/87	2	2	4		1		
Turkey Point Unit 3	25088002	1/15/88							
Turkey Point Unit 3	25089011	6/17/89	2	2	3				
Turkey Point Unit 3	25094002	5/5/94	2	2	3				
Turkey Point Unit 3	25090008	4/15/90	1	2	3				
Turkey Point Unit 4	25192004	3/26/92	1	2	3		1		
Turkey Point Unit 4	25189011	9/15/89	2	2	4				
Turkey Point Unit 4	25189002	4/12/89	2	2	2				
Vogtle Unit 1	42494001	2/2/94	2	1	2	2		1	4
Vogtle Unit 1	42493006	4/18/93	2	1		2		1	4
Vogtle Unit 1	42488028	10/16/88	1	1		2			
Vogtle Unit 2	42592004	4/23/92	1	1		2		1	4
Vogtle Unit 2	42591009	8/13/91	1	1	1				
Vogtle Unit 2	42589006	3/18/89	2	1	2	2		1	4
Waterford Unit 3	38289003	2/4/89							
Waterford Unit 3	38289024	12/23/89	2	1	2		8		
Waterford Unit 3	38291019	8/25/91	2	1	2		8		
Waterford Unit 3	38291022	11/17/91	2	1	2		8		
Waterford Unit 3	38292008	7/26/92							
Waterford Unit 3	38292012	10/2/92	2						
Wolf Creek Unit 1	48287002	1/8/87	2	1	2	2	1	1	4
Wolf Creek Unit 1	48290023	10/23/90				1			

Table B-3. (continued).

Plant Name	LER Number	Event Date	Train Act	RWST-Suction	Segment Demanded			CC-Inj-Hdr	Loop-Inj
					SI-Pump	CC-Pump	SI-Inj-Hdr		
Wolf Creek Unit 1	48293009	5/4/93	1						
Yankee Rowe Unit 1	02987004	2/18/87							
Yankee Rowe Unit 1	02991002	6/15/91							
Zion Unit 1	29591008	5/10/91	2	1	2	2	1	1	8
Zion Unit 1	29592024	12/30/92							
Zion Unit 1	29595022	11/12/95	1	1		1		1	4
Zion Unit 1	29587009	4/30/87	2	1	2	2	1	1	8
Zion Unit 1	29593010	11/10/93							
Zion Unit 1	29591016	11/7/91	2	1	2	2	1	1	8
Zion Unit 1	29596001	1/20/96							
Zion Unit 1	29592019	10/8/92	1	1		1			
Zion Unit 2	30497009	12/2/97	2						
Zion Unit 2	30487006	7/29/87			1		1		1
Zion Unit 2	30488012	12/11/88	2	1	2	2	1	1	8

Appendix C

HPI Unreliability Events, 1987–1997

Appendix C

HPI Unreliability Events, 1987–1997

The events classified as segment failures that occurred as part of an unplanned demand of any segment of the high pressure safety injection (HPI) system were used for the statistical estimation of unreliability. Table C-1 provides a summary description of the three failure events used to determine system unreliability. (Refer to Table B-2 of Appendix B for a listing of all failures associated with the HPI system identified in the LERs.) Table C-2 provides HPI events between 1987–1997 that showed the potential for common cause failure.

Two engineers independently evaluated the full text of each licensee event report (LER) from a risk and reliability perspective. At the conclusion of the independent review, the data from each independent LER review were combined and classification of each event was agreed upon by both engineers. The events identified as failures that could contribute to system unreliability were peer reviewed by the program technical monitor and technical consultants that have extensive experience in reliability and risk analysis. The peer review was conducted to ensure consistent and correct classification of the failure event for the reliability estimation process.

The events identified in this study as segment failures represent actual malfunctions that prevented the successful operation of the particular segment. Segment failures identified in this study are not necessarily failures of the HPI system to complete its mission. As an example, a motor-driven pump segment may have failed to start; however, the redundant motor-driven pump segment may have responded as designed for the mission. Hence, the system was not failed

For the events associated with the injection header and cold leg injection path segments, some LERs identified a degraded flow condition to one or more steam generators. In these events typically no actual flow rates were provided, in some cases a qualitative discussion of the relationship between the flow rates and technical specification or safety analysis report requirements was provided. In these events where degraded flow was indicated, the corrective actions associated with the degraded flow condition were reviewed. In some cases the corrective actions for the degraded flow identified lengthy and extensive testing and inspections, along with component replacements. Because of the extensive corrective actions associated with the identified degraded flow it was assumed that the degraded flow was not sufficient to meet technical specification operability requirements. As a result, the events that identified degraded flow in a feed control segment were classified as failures of the associated feed control segment based on the corrective actions taken by the plant. For the LERs that identified an injection segment flow problem where a flow rate was provided, the segment was classified as failed if the LER stated that the flow rate was less than the technical specification minimum flow rate. Overall, there was no assigned minimum flow value for determining a failed injection segment for this report (e.g. less than 90% of the technical specification minimum). If the plant identified a flow rate less than technical specification minimums or a degraded condition required significant corrective actions, the injection segment was classified as failed.

If the LERs identified injection valves that failed in the normal position for injecting water into the RCS cold leg, these valve inoperabilities were not classified as failures of the injection segment to operate for the mission. However, these malfunctions are considered as system inoperabilities. This classification was based on the need for the injection segment to function successfully for a period of time whether it be an operational or a risk-based mission. Even for an operational mission, as stated in most safety analysis reports, the system must be able to function over an extended period of time until the plant is cooled down to the point where the residual heat removal system is able to be placed in service.

Table C-1. Events used to estimate HPI unreliability.

Plant Name	LER Number	Segment	Failure Mode	Description
Palo Verde 2	52988005	Injection header	FTO	During an inadvertent ESF actuation, the HPSI loop injection valve did not fully open due to a blown fuse. Installed new fuse and valve tested satisfactorily. Cause of the fuse opening could not be determined; fuse failure was concluded to be a random event.
R.E. Ginna	24489003	Train actuation	FTO	Inadvertent safety actuation, only Train A actuated. Train B SI logic failed to actuate due to a wire interfering with a relay plunger. The mechanical interference was due to installation and inspection requirements for a system modification overlooked the possibility of mechanical interference.
Turkey Point 3	25494002	Intermediate-head pump train	FTS	As a result of an inadvertent ESF actuation signal, all equipment responded as designed except 4A SI pump failed to start. Failure attributed to intermittent failure mechanism (failure could not be duplicated during troubleshooting). Replaced blocking and timing relay associated with pump start. Tested satisfactorily.

Table C-2. HPI events identified with potential CCF (1987–1997).

Plant Name	LER Number	Segment	Cause	Method of Discovery	Failure Mode	Description
Arkansas Nuclear 1	31391011	High-head pump train	Procedure	Test	FTR	During testing, the licensee observed that approximately one cup of oil per minute was flowing from the outboard pump bearing area. A similar condition was later found to exist on a redundant pump. The cause of this condition was determined to be lack of procedures for adjustment of the lube oil control valves on the HPI pumps.
Arkansas Nuclear 2	36892007	Injection header	Personnel	Test	FTO	During a test the licensee discovered that the flow rates through HPI legs were unbalanced due to an error made during fabrication by the vendor. A successful flow balance test was completed following installation of refurbished parts.
Beaver Valley 1	33491032	High-head pump train	Design	Design/Review	FTR	The measured ventilation flow from each HPI pump cubicle was found to be less than the flow-rate required by the calculations to maintain motor temperatures within required environmental qualification limits. The cause of the failure was determined to be a partially closed manual isolation damper, common to all three HPI pump rooms. The damper was repaired and placed in the proper position.
Beaver Valley 1	33497039	High-head pump train	Gas Binding	Design/Review	FTS	During an engineering evaluation, the licensee determined that a minimum of one charging/high- head safety injection pump may not have been available to provide emergency core cooling due to intrusion of gas into the suction of the pumps, and subsequent gas binding. The cause of the condition was attributed in part to the design of charging/high-head pump minimum flow recirculation line orifices. Flow orifices were replaced to correct the problem.
Beaver Valley 2	41296005	Injection header RWST suction path	Hardware	Design/Review	FTO	During a re-assessment of an NRC Information Notice, the licensee identified that the failure mechanism described in the IN potentially exists at Beaver Valley Power Station (BVPS) Unit 2 rendering MOVs of the HPI system to fail due to accelerated thermally induced aging. The relays were replaced.

Table C-2. (continued).

Plant Name	LER Number	Segment	Cause	Method of Discovery	Failure Mode	Description
Crystal River 3	30291018	System	Personnel	SI Demand	FTO	During an SI event, an operator inappropriately bypassed HPI actuation. Shift supervision directed out of bypass and HPI actuation was initiated. Administrative guidance was developed on the bypassing of HPI actuation signals.
Diablo-Canyon 1	27590009	Injection header	Hardware	Troubleshooting	FTO	Utility electrical maintenance technicians discovered that several MOVs were in failed condition due to relaxation of spring packs associated with them. The spring packs were replaced with a different model that has not exhibited characteristics of relaxation.
Ginna 1	24494009	Intermediate-head pump train	Hardware	Test	FTR	A leak developed at a socket weld in the common recirculation line for the HPI pumps. The underlying cause of the leak was a crack in the socket weld in the common recirculation line, caused by pipe displacement from air entrainment and pump misalignment. The affected weld was cut out and replaced.
Indian Point 2	24788020	RWST suction path	Design	Alarm	FTO	The level indication for the RWST failed due to subfreezing outdoor temperatures. Additional heating was applied to thaw the affected lines and return them to service.
Oconee 3	28797003	High-head pump train	Hardware	Abnormal Sys. Parameter	FTR	Two out of the three HPI pumps were damaged due to operation with an inadequate suction source. Both Letdown Storage Tank (LDST) level instruments erroneously indicated level was 55.9 inches for about one hour and forty-five minutes prior to the damage to the HPI pumps. Corrective actions included modifications of the LDST level instruments.
Oconee 3	28787006	RWST suction path	Personnel	Design/ Review	FTO	The breakers for the HPI suction valves from the BWST were inadvertently left tagged open while the HPI pump suction valves were closed.
Palo Verde 1	52888004	Intermediate-head pump train	Procedure	Tour	FTS	The unit entered mode 4 without placing the HPI system in operable status. The root cause was a procedural inadequacy in that the procedure did not ensure that equipment was returned to an operable status prior to entering mode 4. To prevent recurrence, the procedure was revised.

Table C-2. (continued).

Plant Name	LER Number	Segment	Cause	Method of Discovery	Failure Mode	Description
Robinson 2	26192018	Intermediate-head pump train	Personnel	Test	FTR	During a test, the licensee declared the both HPI pumps inoperable due to inadequate recirculation flow. The cause of the Safety Injection pump 'B' reduced recirculation flow was attributed to foreign material blockage within the associated minimum flow recirculation line flow orifice.
Robinson 2	26187015	Injection header	Personnel	Abnormal Sys. Parameter	FTO	While attempting to fill the accumulators, the licensee discovered that two of three HPI pumps had been isolated from the high head injection flowpath. The cause of the event was operator error. The operator responsible for the error was counseled and the cooldown procedure involving the affected valves was reviewed from a human factors point of view to prevent repetition of the event.
Sequoyah 2	32890012	High-head pump train	Gas Binding	Test	FTR	The licensee discovered a condition that allows gas binding of the centrifugal charging pump (CCP) suction header. It was subsequently determined that hydrogen gas had been coming out of solution and accumulating in the suction piping as a probable result of gas stripping by the CCP miniflow orifices. In addition, entrainment of hydrogen bubbles from the volume control tank to the CCP suction pipe was determined to be a potential contributor. Long-term corrective actions involved installation of manually-operated vent valves in vertical lines where gas has been accumulating to enable Operations personnel to vent the system.
Sequoyah 2	32888005	High-head pump train	Maintenance	Tour	FTR	The train A centrifugal charging pump failed due to a hardware defect. Subsequent inspections showed that train B pump was vulnerable to the identical hardware defect. The cause of hardware failure was the use of incorrect parts.
Shearon Harris 1	40091008	High-head pump train	Design	Test	FTR	The failures (damaged relief valves and drain connections) in alternate miniflow lines for both charging and safety injection caused the HPI system to remain in a failed condition. The system was repaired and procedures were revised to preclude recurrence.

Table C-2. (continued).

Plant Name	LER Number	Segment	Cause	Method of Discovery	Failure Mode	Description
Vogtle 1	42496010	Intermediate-head pump train	Procedure	Tour	FTR	An investigation of temperature differences between the safety injection pump motor coolers discovered that the motor cooling for this pump had been significantly degraded due to improper gasket installation and incorrect assembly of the motor coolers. The causes of this event were improper gasket installation and inadequate procedural guidance resulting in incorrect assembly of the motor coolers. The motor coolers were reassembled properly and the pump was returned to service.
Wolf Creek 1	48290025	Intermediate-head pump train	Hardware	Alarm	FTR	Both pump trains were in failed condition due to frozen miniflow lines.
Zion 1	29596007	Intermediate-head pump train	Environment	Abnormal Sys. Parameter	FTR	The local suction pressure gages for the safety injection pumps were over-ranged with indication greater than the upper limit of 60 psig. Increased pressures were caused by restriction in HPI piping. The cause of the restriction was a design deficiency that allowed freezing in HPI recirculation piping.
Zion 2	30491001	Intermediate-head pump train	Environment	Test	FTR	During a test, both HPI pumps failed to satisfy the minimum recirculation flow. The cause of the failure was determined to a flow restriction. After the flow restriction was flushed out, the system operated as required.

C-1.1 Special Interest Events

In addition to the events classified as failures that would prevent the HPI system from successful operation during a small LOCA or steam generator tube rupture, several events not considered for the unreliability calculation are described below. The first event was classified as a human error of commission and the second event is a design-related event.

Error of Commission

In the operational data consisting of unplanned demands, there was one event in which automatic actuation of all trains of HPI were intentionally bypassed by operator action when the system was required to be in operation by plant technical specifications. Although this event was not classified as a failure for the purposes of quantifying HPI unreliability, it did occur during an unplanned demand and is discussed here because of the human error associated with the event.

The event occurred when the plant was being returned to power operation following a short shutdown for maintenance. The plant was at 11% and power was being slowly raised in steps. During each of the power increases, Reactor Coolant System (RCS) pressure increased to the 2205 psig setpoint for opening of the Pressurizer Spray Valve. The "closed" indicating lamp did not extinguish in either instance. The spray valve failed to close, resulting in a steady decrease in RCS pressure over the next 19 minutes. Troubleshooting strategies in the control room during this time period included taking manual control of the spray valve and selecting it to the "closed" position. This was done despite the fact that the spray valve indication never changed from indicating full closure of the valve which had led the operators to believe it had not opened.

The operators concluded that a LOCA was not in progress, however they still suspected that the pressurizer heaters were not functioning normally. They also evaluated the possibility that the continuing RCS depressurization might be the result of a secondary plant induced overcooling of the RCS. This was based on secondary plant anomalies that existed just prior to the onset of the transient. RCS pressure decreased to the Reactor Protection System (RPS) low RCS pressure setpoint of 1800 psig, resulting in a reactor trip. Following the reactor trip, RCS pressure did not recover as expected. RCS pressure decreased below 1700 psig and the permissive to manually bypass automatic High Pressure Injection (HPI) actuation had been met. Prior to reaching 1500 psig, one of the control room operators announced and bypassed both trains of HPI but did not receive permission nor was his announcement acknowledged although operator interviews indicated that the Senior Reactor Operator (SRO) on duty was aware of the bypass. This action was inappropriate since the reason for the ongoing RCS depressurization had not yet been diagnosed and management concurrence with the ES bypass had not been obtained. The acting Operations Superintendent, after completing phone notification of the Plant Manager, recognized that the operator had bypassed ES and recommended, to the SRO on duty, removal of the bypass. While this action was being discussed, two of three ES low RCS pressure (1500 psig) bistables tripped and the SRO on duty immediately ordered the bypass removed, at which time full HPI actuation occurred automatically. Full HPI flow to the RCS occurred for approximately one minute, after which the system was once again placed in ES bypass, per the procedure, so that equipment could be manually controlled. HPI flow continued for approximately another minute and was then terminated due to the rapid recovery in RCS pressure. The ES bistables were then reset to arm the HPI System. RCS pressure again began to decrease due to the spray valve being failed open. One of the three ES bistables tripped. As RCS pressure decreased to a minimum value of 1503 psig, the control room crew bypassed ES, since a full actuation was not necessary based on observed indications. Makeup flow to the RCS was increased by opening the HPI make-up valve. Over the next 10 minutes, RCS pressure gradually recovered as the increased makeup flow filled the pressurizer and compressed the pressurizer steam bubble.

After RCS pressure had increased to approximately 1700 psig, makeup flow was terminated. However, pressurizer temperature continued to slowly decrease. The Pressurizer Spray Block Valve was closed and stable RCS conditions were achieved, terminating the event.

The cause of this event was the failure of the spray valve. The failure was compounded by the concurrent failure of the position indication for the valve. The spray valve failed to close in both the manual and automatic modes of operation.

This particular EOC was omitted from the HPI unreliability calculations since (a) the error could not have occurred during a small LOCA or a steam generator tube rupture (SGTR) and the system unreliability is calculated for mitigating these events, and (b) the system was placed in bypass after a minute of injection and as a result, the operator error is more likely classified as a “procedure non-compliance” rather than a system failure.

C-1.1.1 Design

While at 30% power, both pressurizer spray valves were modulating to control pressure, the feedback arm linkage on pressure control valve (Loop A spray valve) became disengaged from the valve stem connecting plate. This caused the available Instrument Air to be ported to the valve actuator forcing the spray valve to the open position. Spray flow increased causing the Reactor Coolant System (RCS) pressure to decrease. As pressure decreased, the operator noticed that the "red" open indication light was still present on both spray valves. The operator placed the two spray valve controllers in manual and verified that there was no demand on the controllers. Power was reduced in order to secure the two reactor coolant pumps feeding pressurizer spray without generating an automatic reactor trip. This was done to stop the depressurization transient. An automatic reactor trip due to low pressurizer pressure occurred at 16% power. A safety injection, accompanied by containment isolation, also occurred at this time. RCPs 2A and 2D were stopped manually. The operators implemented the Emergency Operating Procedures and stabilized the plant. The safety injection and Phase A isolation signals were reset and instrument air was resupplied to the Reactor Containment Building. Due to the mode of failure of the spray valve, the valve again failed open on resupply of instrument air. Pressurizer pressure dropped below the nominal safety injection setpoint but an automatic safety injection signal was not received due to the block/reset feature of the safety injection actuation circuitry. By design, the safety injection trains were blocked when the reactor trip breakers were open and safety injection actuation had occurred. The operators did not manually inject safety injection because the operators were incorrectly assuming that the Emergency Operating Procedure criteria for safety injection were still applicable even though the Emergency Operating Procedure was exited earlier. The transient was terminated and the plant was returned to normal operating pressure and temperature. Later, the reactor trip breakers were closed which automatically reset the safety injection actuation capability. The actuation of HPI did not inject coolant into the RCS because the minimum pressure reached was 1725 psig and the shutoff head of the High Head Safety Injection (HHSI) pumps is 1680 psig (plus 20 psig suction pressure).

The time between the event initiation (2235 psig and decreasing) and the automatic reactor trip was 281 seconds. Even though power was being reduced rapidly, review determined that the operators should have initiated a manual reactor trip before the automatic system was challenged. From the time that the Emergency Operating Procedures were exited to the time when the reactor trip breakers were closed, the plant was in violation of Technical Specifications. The plant was in this Technical Specification for approximately 2 hours. The Technical Specifications require two of three safety injection automatic circuits to be operable in Modes 1 through 4. All safety injection trains were blocked due to the safety injection block design feature when the reactor trip breakers are open. This particular system actuation failure was omitted from the HPI unreliability calculations since (a) the initial demand for HPI was successful, and (b) manual actions can be taken during subsequent demands to start HPI.

Appendix D

Supporting Information of HPI System Unreliability Analysis

Appendix D

Supporting Information of HPI System Unreliability Analysis

D-1. RUN TIME CALCULATIONS

Table D-1 provides a summary of the run time estimation. An average run time was calculated for each pump type. An average run time was calculated for the high-head system/train. An average run time was computed for the intermediate-head system/train. These averages were then used to estimate run times for pump demands with unknown run times. Further, the uncertainty arising from using the projected run times were not modeled in failure rate estimates, since it is not significant compared to modeled statistical uncertainty. Section A-2.2.3 of Appendix A provides the additional information about the run time evaluation.

The cumulative run time (actual plus projected) based on the 124 unplanned demands for the high-head pump trains is approximately 50.3 hours. For the intermediate-head pump train, the cumulative run time (actual plus projected) was 151.7 hours based on 115 unplanned demands. For the combined pump trains, the unplanned demands resulted in 202 cumulative hours of run time (actual plus projected).

Table D-1. HPI pump run times (hours) estimated from the HPI unplanned demands.

	Pump Type		
Run Time Events	High-head	Intermediate-head	Combined
Number known[a]	105	114	219
Known run time (hr)	27.5	70.9	98.4
Average known run time (hr)	0.26	0.62	0.45
Number unknown	87	130	217
Projected unknown run time (hr)	22.8	80.8	103.6
Total projected run time (hr)	50.3	151.7	202.0

a. The value represents the number of successful HPI system/train events involving the given pump type and the HPI system/train run time was specified in the LER.

D-2. SUMMARY OF CUT SET CONTRIBUTION TO HPI UNRELIABILITY BASED ON IPE FAILURE DATA AND 1987–1997 EXPERIENCE FOR THE SIX REFERENCE PLANTS

To determine the reasons for the differences between the IPEs and those based on the 1987–1997 experience, the cut sets for the six references plants (both IPE and 1987–1997 experience) generated for this study were compared with each other. The results are based on the model assumptions presented in the Section 3.2.1 of the main report. Table D-2 provides a summary tabulation of the cut set review. The contributions are based on the cutset contribution to the mincut upper bound of HPI unreliability.

Table D-2. Summary comparison of cut set contribution based on IPE failure probabilities and failure probabilities estimated from the 1987–1997 experience and using the HPI fault tree shown in Figure 4 for the six HPI design classes. (A half-hour mission time is used in the unreliability calculations.)

Design Class	Reference Plant	1987–1997 Exp. ÷ PRA/IPE	Contributors to HPI Unreliability Based on the Fault Tree Model in Figure 4 and IPE Failure Data	Contributors to HPI Unreliability Based on the Fault Tree Model in Figure 4 and 1987–1997 Experience
1	Waterford 3	0.4	89.3%—CCF of motor-driven pumps to start (8.2E-04) 2.6%—Independent failures of motor-driven pumps to start and motor-driven pumps unavailable due to maintenance out of service (2.4E-05) 2.6%—Independent failures of motor-driven pumps to start and motor-driven pumps unavailable due to maintenance out of service (2.4E-05) 2.5%—Independent failure of both motor-driven pumps failing to start (2.3E-05) 0.8%—CCF of motor-driven pumps to run (7.2E-06)	32.7%—CCF of motor-driven pumps to start (1.1E-04) 28.4%—CCF of motor-driven pumps to run (9.4E-05) 16%—Independent failure of RWST suction source (5.3E-05) 11.6%—CCF of pump injection headers (3.8E-05) 2.7%—Independent failures of motor-driven pumps to start (9.0E-06) 1.7%—Independent failures of motor-driven pump to start and motor-driven pump unavailable due to maintenance out of service (5.7E-06) 1.7%—Independent failures of motor-driven pump to start and motor-driven pump unavailable due to maintenance out of service (5.7E-06) 1.1%——Independent failures of motor-driven pump to run and motor-driven pump to start (3.8E-06) 1.1%——Independent failures of motor-driven pump to run and motor-driven pump to start (3.8E-06)

Table D-2. (continued).

Design Class	Reference Plant	1987–1997 Exp. ÷ PRA/IPE	Contributors to HPI Unreliability Based on the Fault Tree Model in Figure 4 and IPE Failure Data	Contributors to HPI Unreliability Based on the Fault Tree Model in Figure 4 and 1987–1997 Experience
2	Oconee 1	0.9	85%—CCF of pumps RWST suction MOVs (2.7E-04) 8.2%—Independent failure of train A discharge section and motor-driven pump C unavailable due to maintenance out of service (2.6E-05) 5%—Independent failure of train A and train B pump suction MOVs (1.6E-05) 0.4%—Independent failure of train A injection check valve section and motor-driven pump C unavailable due to maintenance out of service (1.3E-06)	65.7%—CCF of motor-driven discharge section (1.8E-04) 19.4%—Independent failure of RWST suction source (5.3E-05) 3.8%—Independent failure of motor-driven discharge sections (1.0E-05) 3.5%—Independent failure of motor-driven pump C to start and failure of train A discharge section (9.6E-06) 2.3%—CCF of motor-driven pumps to run (6.4E-06) 2.2%—Independent failure of train A discharge section and motor-driven pump C unavailable due to maintenance out of service (6.1E-06) 1.5%—Independent failure of train A discharge section and motor-driven pump C fails to run (4.0E-06) 1.2%—Independent failure of channel A and B actuation signal (3.2E-06)

Table D-2. (continued).

Design Class	Reference Plant	1987–1997 Exp. ÷ PRA/IPE	Contributors to HPI Unreliability Based on the Fault Tree Model in Figure 4 and IPE Failure Data	Contributors to HPI Unreliability Based on the Fault Tree Model in Figure 4 and 1987–1997 Experience
3	Shearon Harris 1	0.8	50.9%—Independent failure of RWST suction check valve (2.8E-04) 13.6%—CCF of motor-driven pump discharge path into BIT (7.5E-05) 13.6%—CCF of motor-driven pump discharge path out of BIT (7.5E-05) 13.6%—CCF of pump suction MOVs from RWST (7.5E-05) 3.2%—Independent failure of motor-driven pump A discharge section and motor-driven pump B unavailable due to maintenance out of service (1.8E-05) 1.6%—Independent failures of motor-driven pump discharge segments into BIT (9.0E-06) 1.6%—Independent failures of motor-driven pump discharge segments out of BIT (9.0E-06) 1.6%—Independent failures of motor-driven pump suction RWST MOVs (9.0E-06)	38.7%—CCF of motor-driven discharge segments into boron injection tank (BIT) (1.8E-04) 38.7%—CCF of motor-driven discharge segments out of BIT (1.8E-04) 11.5%—Independent failure of RWST suction source (5.3E-05) 4.3%—CCF of motor-driven pumps to run (2.0E-05) 2.2%—Independent failures of motor-driven pumps discharge segments into BIT (1.0E-05) 2.2%—Independent failures of motor-driven pumps discharge segments out of BIT (1.0E-05) 0.8%—Independent failures of motor-driven pump A to run and failure of motor-driven pump B to start (3.8E-06)

Table D-2. (continued).

Design Class	Reference Plant	1987–1997 Exp. ÷ PRA/IPE	Contributors to HPI Unreliability Based on the Fault Tree Model in Figure 4 and IPE Failure Data	Contributors to HPI Unreliability Based on the Fault Tree Model in Figure 4 and 1987–1997 Experience
4	Turkey Point 3	0.5	70.8%—CCF of motor-driven pumps discharge segments (4.1E-04) 4.5%—Independent failure of motor-driven pumps discharge segments (2.6E-05) 1.7%—Independent failure of Unit 4 motor-driven pump A unavailable due to maintenance out of service and CCF of Unit 3 motor-driven pumps to run (9.8E-06) 1.7%—Independent failure of Unit 4 motor-driven pump B unavailable due to maintenance out of service and CCF of Unit 3 motor-driven pumps to run (9.8E-06) 1.7%—Independent failure of Unit 3 motor-driven pump A unavailable due to maintenance out of service and CCF of Unit 4 motor-driven pumps to run (9.8E-06) 1.7%—Independent failure of Unit 3 motor-driven pump B unavailable due to maintenance out of service and CCF of Unit 4 motor-driven pumps to run (9.8E-06) 1.3%—Independent failure of Unit 3 motor-driven pump A to run and CCF of Unit 4 motor-driven pump A to run (7.4E-06) 1.3%—Independent failure of Unit 3 motor-driven pump A to run and CCF of Unit 4 motor-driven pump B to run (7.4E-06)	66%—CCF of motor-driven pumps discharge segments (1.8E-04) 15.5%—CCF of all motor-driven pumps to start (4.2E-05) 12.9%—CCF of all motor-driven pumps to run (3.5E-05) 3.8%—Independent failure of motor-driven pump discharge segments (1.0E-05) 1.2%—Independent failures of channel A and B actuation signal (3.2E-06)

Table D-2. (continued).

Design Class	Reference Plant	1987–1997 Exp. ÷ PRA/IPE	Contributors to HPI Unreliability Based on the Fault Tree Model in Figure 4 and IPE Failure Data	Contributors to HPI Unreliability Based on the Fault Tree Model in Figure 4 and 1987–1997 Experience
5	South Texas Project 1	8.3	96.8%—CCF of motor-driven pumps to start (3.1E-05) 2.7%—CCF of motor-driven pumps to run (8.5E-07) 0.1%—Independent failures of motor-driven pumps to start (3.6E-08)	40.1%—CCF of motor-driven pump discharge segments (1.1E-04) 20.5%—CCF of motor-driven pumps to start (5.4E-05) 20.1%—Independent failures of RWST suction source (5.3E-05) 19%—CCF of motor-driven pumps to run (5.0E-05)

Table D-2. (continued).

Design Class	Reference Plant	1987–1997 Exp. ÷ PRA/IPE	Contributors to HPI Unreliability Based on the Fault Tree Model in Figure 4 and IPE Failure Data	Contributors to HPI Unreliability Based on the Fault Tree Model in Figure 4 and 1987–1997 Experience
6	Braidwood 1	1619	27.9%—Independent failure of CHG discharge check valve segment and independent failure of HHSI suction check valve (1.0E-08) 27.9%—Independent failure of CHG suction check valve segment and independent failure of HHSI suction check valve (1.0E-08) 5.9%—Independent failure of CHG discharge check valve segment and CCF of HHSI motor-driven pumps to start (2.1E-09) 5.9%—Independent failure of CHG suction check valve segment and CCF of HHSI motor-driven pumps to start (2.1E-09) 4.2%—Independent failure of HHSI suction check valve segment and CCF of CHG discharge segment (1.5E-09) 4.2%—Independent failure of HHSI suction check valve segment and CCF of CHG suction segment (1.5E-09) 2.5% —Independent failure of CHG discharge check valve segment and independent failure of HHSI motor-driven pumps to start (9.0E-10) 2.5%—Independent failure of CHG suction check valve segment and independent failure of HHSI motor-driven pumps to start (9.0E-10) 2.2%–Independent failure of RWST suction (8.0E-10)	93%—Independent failures of RWST suction source (5.3E-05) 5.7%—Independent failure of channel A and B actuation signal (3.2E-06) 1%—CCF of CHG discharge segment and independent failure of HHSI discharge segment (5.7E-07) 0.1%—CCF of CHG motor-driven pumps to run and independent failure of HHSI discharge segment (6.4E-08)

D-3. ADDITIONAL INFORMATION SUPPORTING THE UNRELIABILITY ANALYSIS

Information and results to support the high pressure injection (HPI) system unreliability information provided in the main body of this report are presented. Figure D-1 provides the simple P&ID schematics used to define the piping segments for the six reference plants. The labeling of the segments correlate to the naming convention used in Figure 4 of the main body of the report.

The plant-specific estimates of HPI operational unreliability and associated 90% uncertainty intervals calculated from the 1987–1997 experience are shown in Table D-3. Due to the sparseness of the failure to run data, both failures and run time, the PRA-based mission uses the same operational mission assumptions. Therefore, Table D-3 also represents the PRA-based values for comparison to the IPE results. Similar types of estimates, except they are based on PRA/IPE information, are shown in Table D-4. The results presented in Table D-4 are calculated from the PRA/IPE failure rates and based on a half-hour mission time.

The listing of cut sets contributing 0.1% or greater to HPI unreliability based on a half-hour mission time and the 1987–1997 experience are tabulated in Table D-5. Table D-6 lists the IPE generated cut sets contributing 0.1% or greater to HPI unreliability using the half-hour mission time and the IPE failure probabilities. The fault tree model appears in Figure 4 of the main body of the report.

The names of the basic event identified in the cutset listing of Table D-5 follow the naming convention assigned to the segments of the various HPI design classes shown in Figure D-1. However, the failure events identified in the IPEs were at a component level, and therefore it was not possible to follow exactly the basic event naming of the pipe segments shown in Figure D-1. With the use of Figure D-1 it is possible to identify the pipe segment appearing in the cutset listing of Table D-6.

The following are descriptions of the basic event identifiers used in the cutset listing provided in Table D-5. (Section A-1 in Appendix A identifies the boundaries and components included in the various pipe segments.) The first four characters of the basic event descriptor is the plant ID. For example, WGS3 stands for the "Waterford Generating Station Unit 3." Following the plant name identifier is the segment name identifier and failure mode associated with the general label used in the simplified block diagrams shown in Figure D-1. The following labels are used to encode the pipe segment information into the fault tree model:

- CC – charging or high-head injection
- SI – intermediate-head injection
- MOV – motor operated valve and generally used as part of the injection header descriptor (e.g., MOV-INJ-HDR)
- CKV – check valve and generally used as part of the cold leg injection path descriptor (CKV-LOOP-INJ)
- FTR – failure to run of the pump train
- FTS – failure to start of the pump train

- FTO – failure to operate of the injection header, cold leg injection segments or the actuation logic channels, respectively

- RWST-SUCT– RWST suction segment

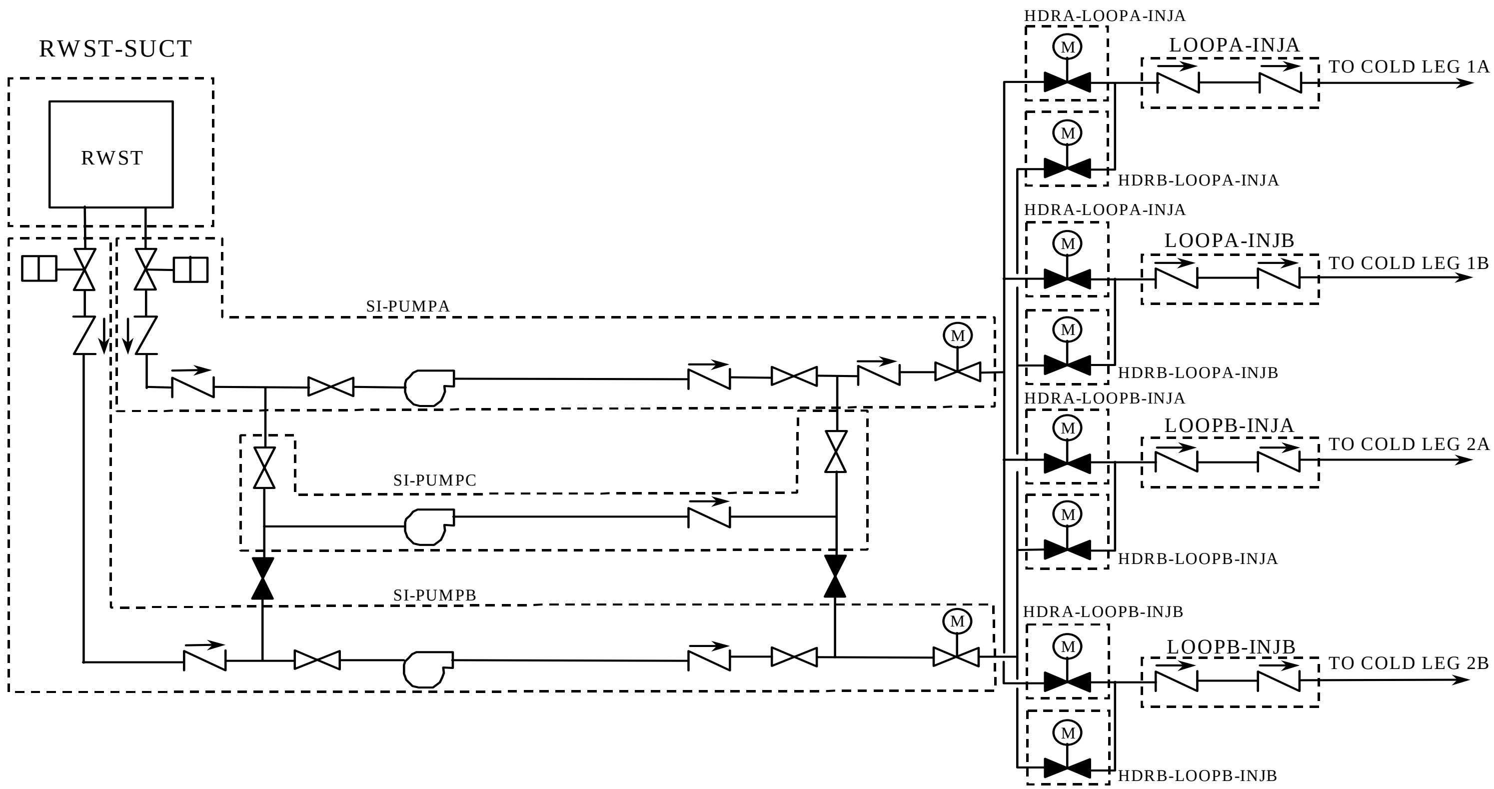
- PUMP*y* – pump train and (e.g., PUMPA, PUMPB, etc.)

- INJ-HDR*y* – pump injection header segment and associated train identifier (e.g., INJ-HDRA, INJ-HDRB, etc.)

- LOOP *x*-INJ*y* – cold-leg (loop) injection segment and associated train identifier (e.g., LOOPA-INJA, etc.)

- ACT-CHANL *x*– the logic circuits for initiation of the HPI system and associated train identifier (e.g., ACT-CHANLA, etc.)

- ALPHA–identifies the basic event represent a common cause failure (CCF) probability factor. A description of the alpha factors used for the CCF failures is provided in Table 3 in the main body in the report.



Waterford 3 (Design Class 1)
*Pump C is installed spare

Figure D-1. Simplified P&ID schematics of the HPI systems for the six reference plants.

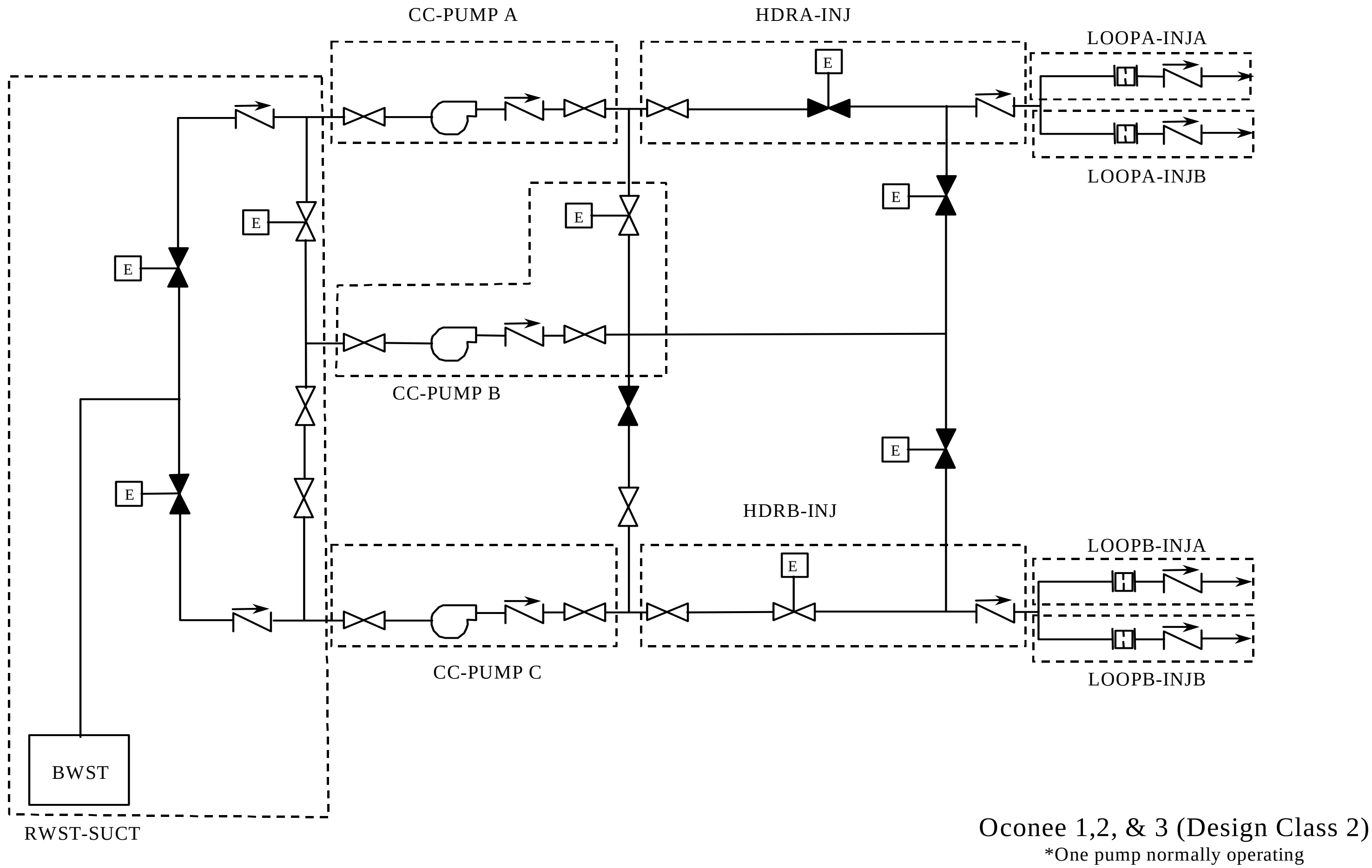
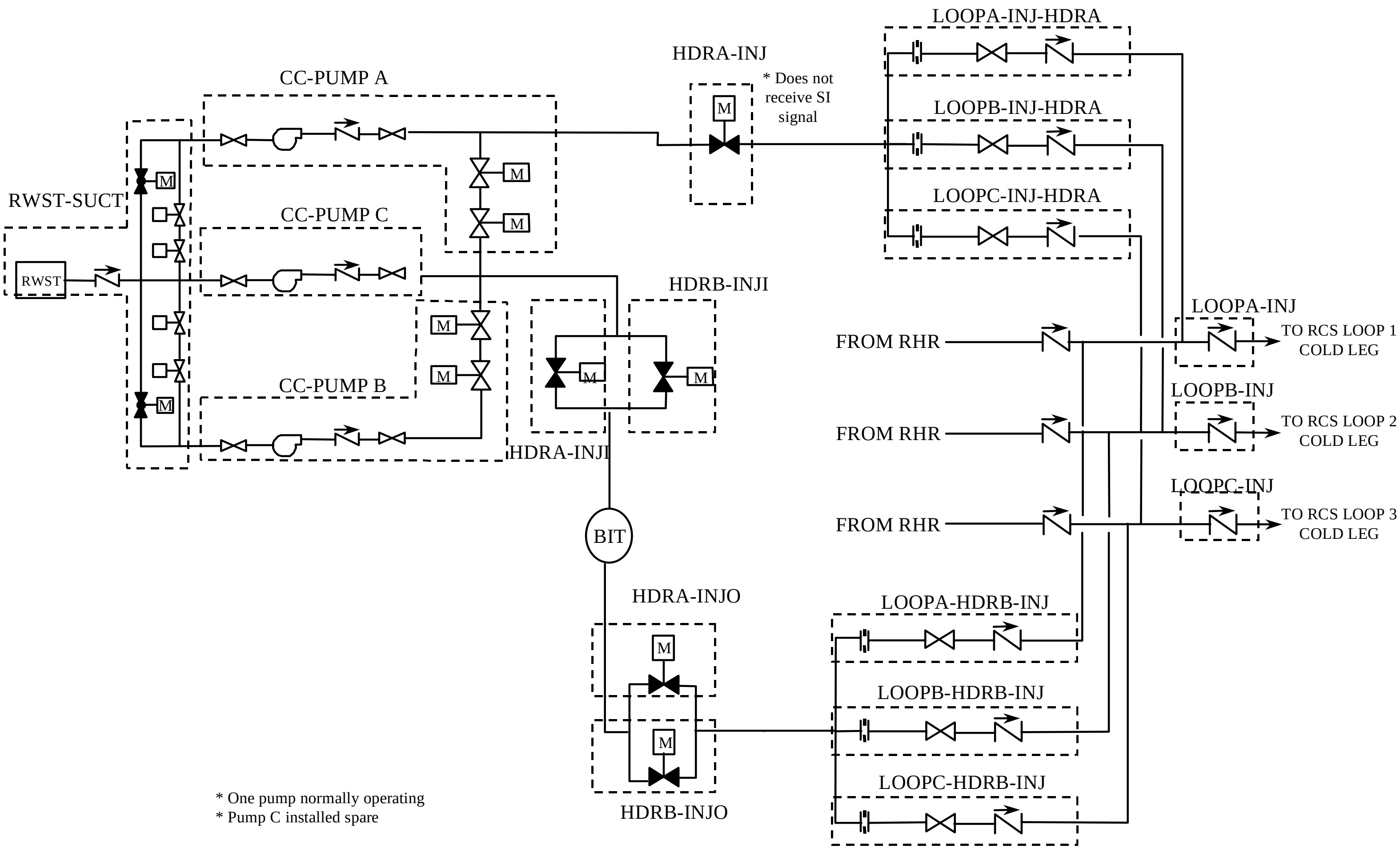
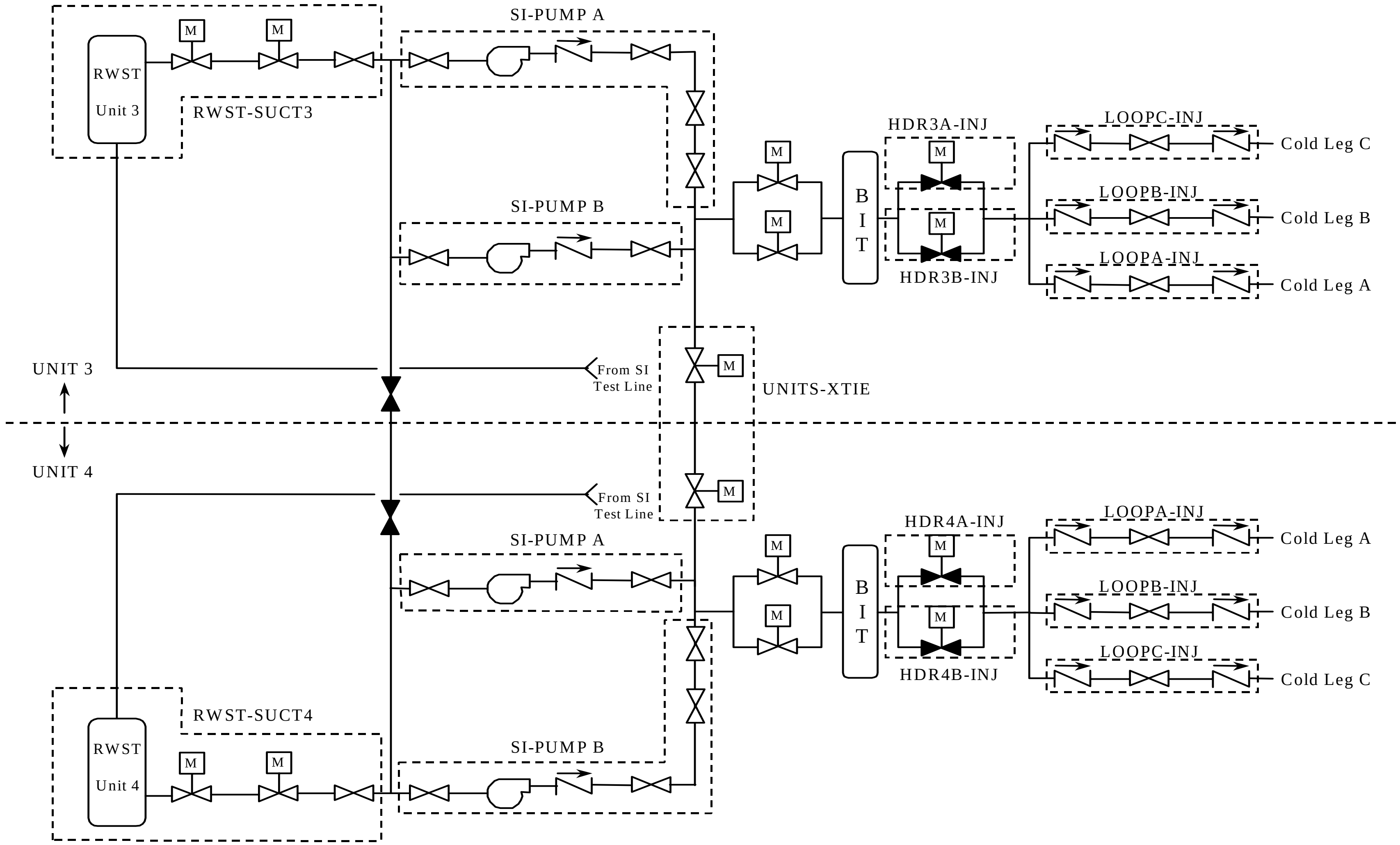


Figure D-1. (continued).



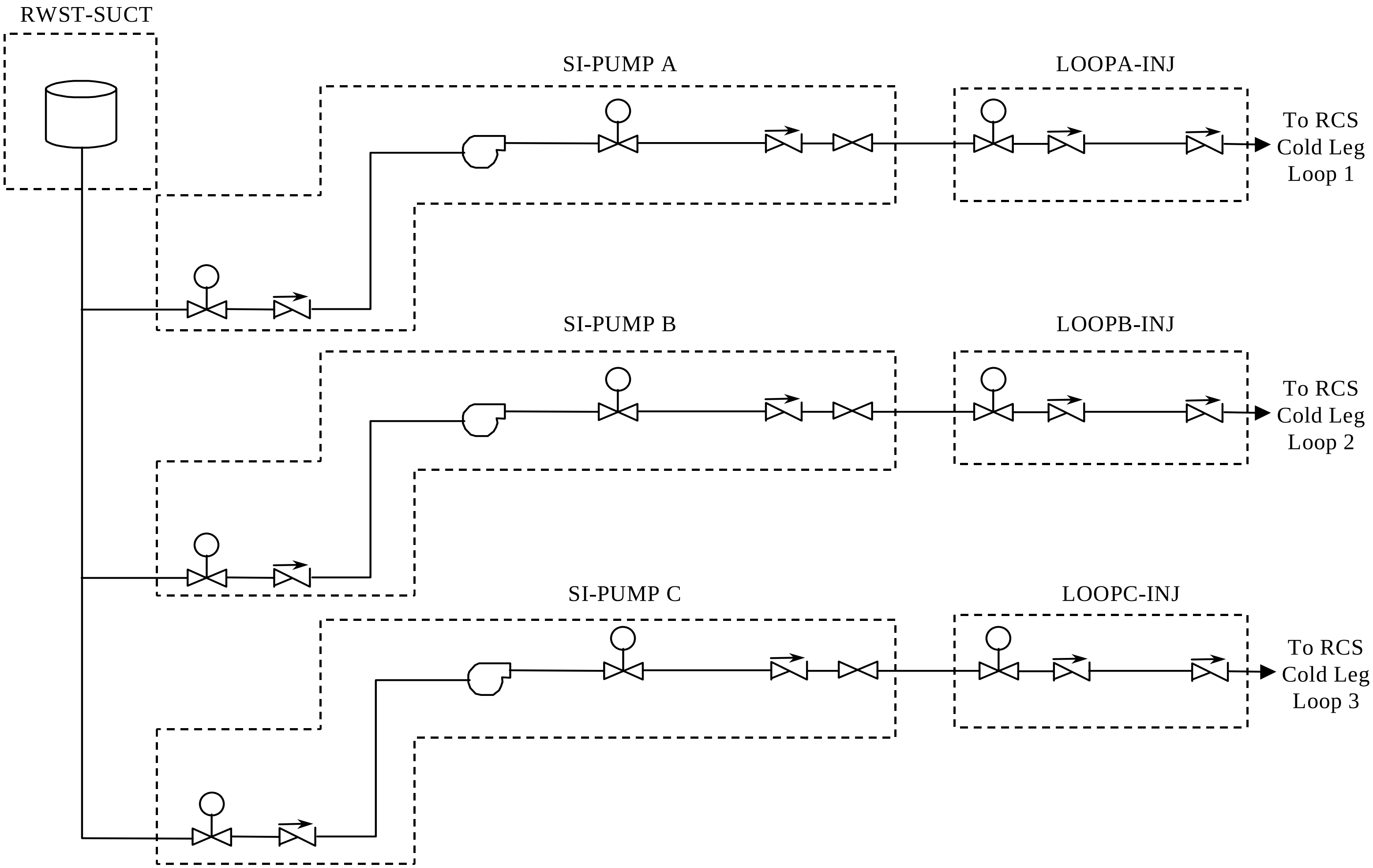
Harris (Design Class 3)

Figure D-1. (continued).



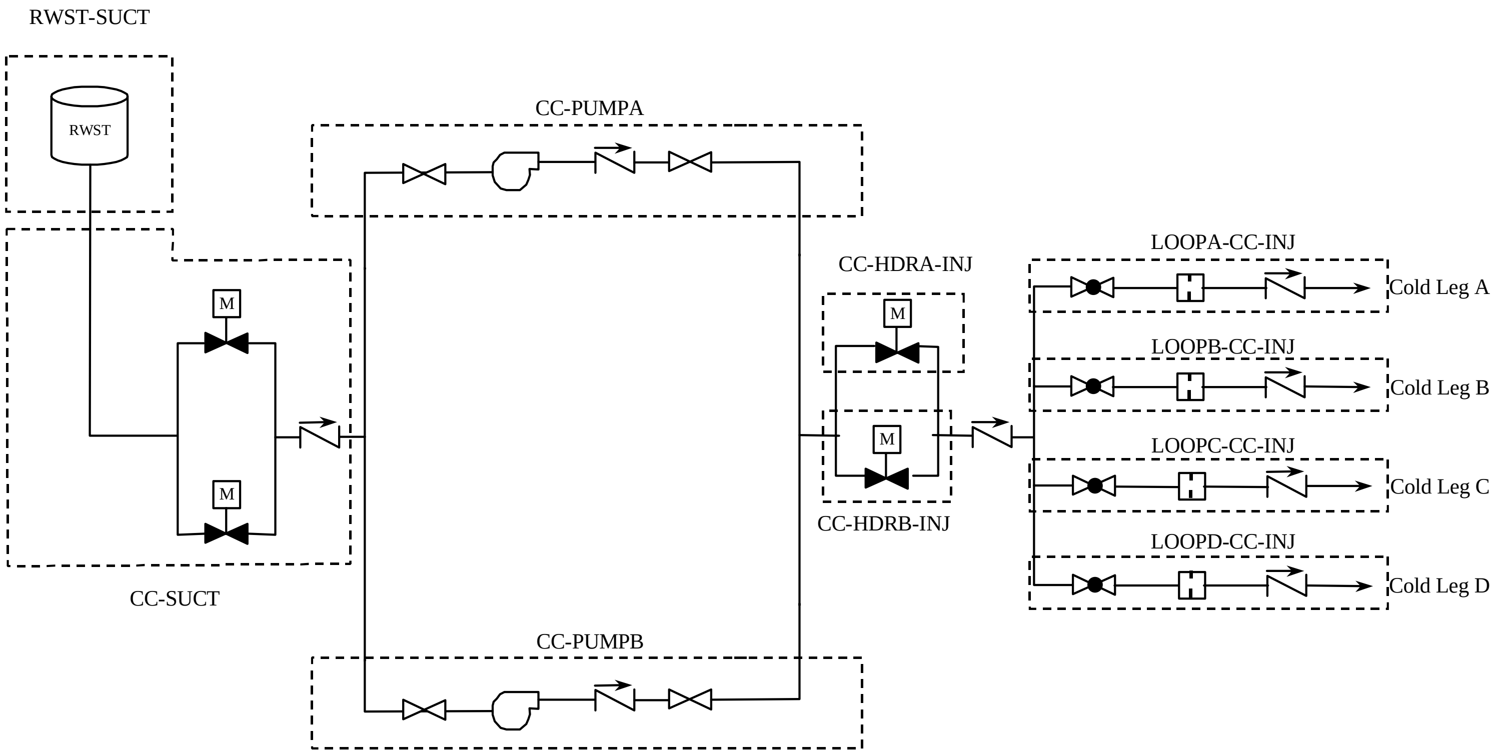
Turkey Point 3 & 4 (Design Class 4)

Figure D-1. (continued).



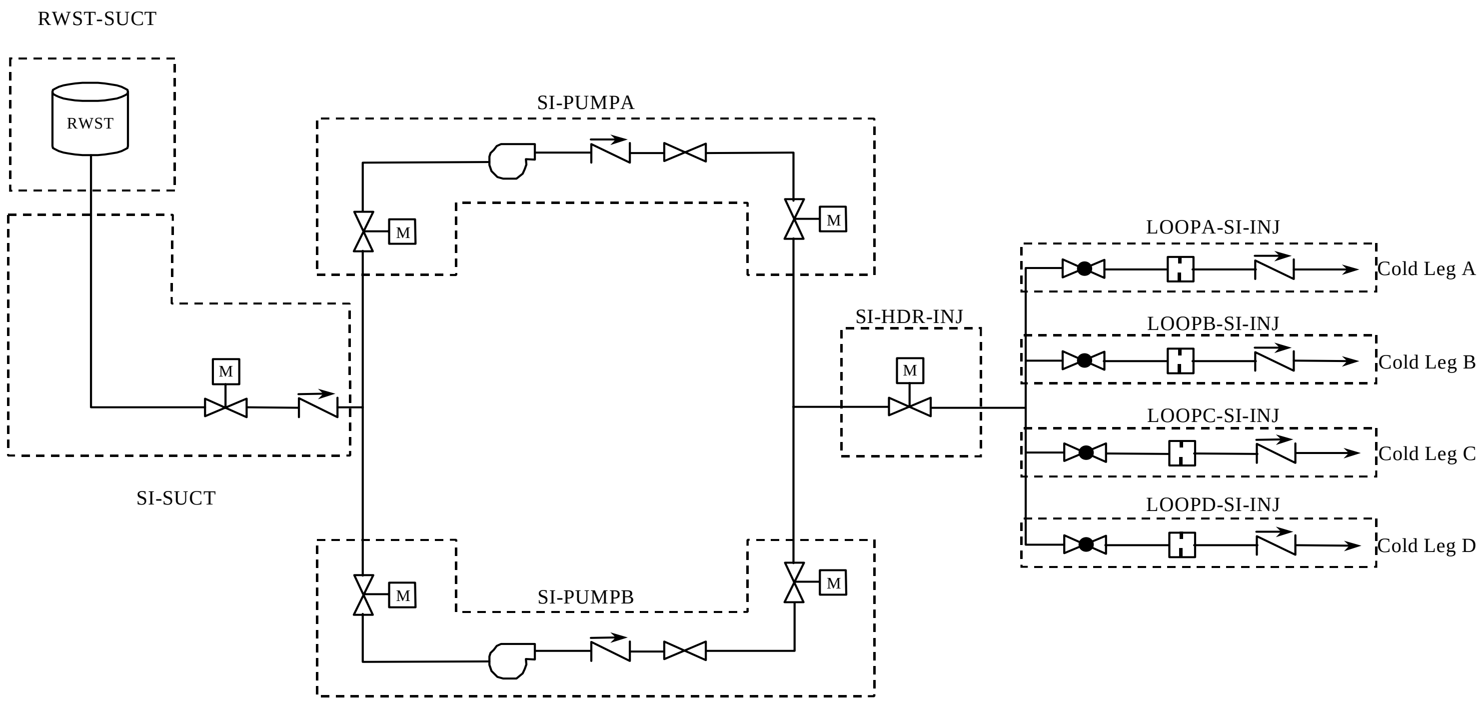
South Texas 1 (Design Class 5)

Figure D-1. (continued).



Braidwood 1 and 2 High-Head Injection System (Design Class 6)

Figure D-1. (continued).



Braidwood 1 and 2 Intermediate-Head Injection System (Design Class 6)

Figure D-1. (continued).

Table D-3. Plant-specific estimates of HPI unreliability (operational mission; half hour) and 90% uncertainty based on the 1987–1997 operational experience. (This set corresponds to the "1987–1997 Experience" plotted.)

HPI Design Class	Plant	5th Percentile of HPI Operational Unreliability	HPI Operational Unreliability Mean	95th Percentile of HPI Operational Unreliability
1	Arkansas Nuclear One 1	3.22E-05	1.26E-04	2.97E-04
1	Arkansas Nuclear One 2	1.27E-04	3.42E-04	7.16E-04
1	Calvert Cliffs 1	1.27E-04	3.42E-04	7.16E-04
1	Calvert Cliffs 2	1.27E-04	3.42E-04	7.16E-04
1	Davis-Besse	1.44E-04	3.80E-04	7.80E-04
1	Kewaunee	6.38E-04	3.51E-03	8.74E-03
1	Millstone 2	1.26E-04	3.39E-04	6.84E-04
1	Palisades	1.28E-04	3.41E-04	7.12E-04
1	Palo Verde 1	1.26E-04	3.39E-04	6.84E-04
1	Palo Verde 2	1.26E-04	3.39E-04	6.84E-04
1	Palo Verde 3	1.26E-04	3.39E-04	6.84E-04
1	Point Beach 1	1.46E-04	3.81E-04	7.76E-04
1	Point Beach 2	1.46E-04	3.81E-04	7.76E-04
1	Prairie Island 1	6.38E-04	3.51E-03	8.74E-03
1	Prairie Island 2	6.38E-04	3.51E-03	8.74E-03
1	San Onofre 2	1.26E-04	3.39E-04	6.84E-04
1	San Onofre 3	1.26E-04	3.39E-04	6.84E-04
1	St. Lucie 1	1.28E-04	3.41E-04	7.12E-04
1	St. Lucie 2	1.28E-04	3.41E-04	7.12E-04
1	Waterford 3	1.26E-04	3.39E-04	6.84E-04
2	Crystal River 3	2.40E-05	1.43E-04	3.71E-04
2	Fort Calhoun	1.29E-04	3.98E-04	8.62E-04
2	Ginna	1.13E-04	3.60E-04	7.91E-04
2	Oconee 1	5.96E-05	2.85E-04	7.09E-04
2	Oconee 2	5.96E-05	2.85E-04	7.09E-04
2	Oconee 3	5.96E-05	2.85E-04	7.09E-04
2	Three Mile Island 1	2.45E-05	1.43E-04	3.72E-04
3	Beaver Valley 1	2.87E-04	3.47E-03	1.20E-02
3	Beaver Valley 2	2.87E-04	3.47E-03	1.20E-02
3	Farley 1	1.13E-04	4.88E-04	1.23E-03
3	Farley 2	1.13E-04	4.88E-04	1.23E-03
3	H.B. Robinson	1.85E-04	4.99E-04	1.02E-03
3	Maine Yankee	3.60E-05	1.39E-04	3.32E-04
3	North Anna 1	1.07E-04	4.79E-04	1.21E-03
3	North Anna 2	1.07E-04	4.79E-04	1.21E-03
3	Shearon Harris 1	1.09E-04	4.82E-04	1.17E-03

Table D-3. (continued).

HPI Design Class	Plant	5th Percentile of HPI Operational Unreliability	HPI Operational Unreliability Mean	95th Percentile of HPI Operational Unreliability
3	Summer 1	7.82E-05	3.21E-04	7.87E-04
3	Surry 1	6.61E-05	2.83E-04	6.93E-04
3	Surry 2	6.61E-05	2.83E-04	6.93E-04
4	Turkey Point 3	7.61E-05	2.83E-04	6.82E-04
4	Turkey Point 4	7.61E-05	2.83E-04	6.82E-04
5	Indian Point 2	7.88E-05	2.40E-04	5.18E-04
5	Indian Point 3	6.87E-05	2.03E-04	4.38E-04
5	South Texas 1	8.24E-05	2.64E-04	5.91E-04
5	South Texas 2	8.24E-05	2.64E-04	5.91E-04
6	Braidwood 1	2.15E-06	6.06E-05	2.14E-04
6	Braidwood 2	2.15E-06	6.06E-05	2.14E-04
6	Byron 1	2.14E-06	6.06E-05	2.13E-04
6	Byron 2	2.14E-06	6.06E-05	2.13E-04
6	Callaway	2.53E-06	6.14E-05	2.13E-04
6	Catawba 1	2.14E-06	6.06E-05	2.13E-04
6	Catawba 2	2.14E-06	6.06E-05	2.13E-04
6	Comanche Peak 1	2.59E-06	6.14E-05	2.13E-04
6	Comanche Peak 2	2.59E-06	6.14E-05	2.13E-04
6	Cook 1	1.58E-06	6.02E-05	2.16E-04
6	Cook 2	1.58E-06	6.02E-05	2.16E-04
6	Diablo Canyon 1	3.11E-06	6.22E-05	2.18E-04
6	Diablo Canyon 2	3.11E-06	6.22E-05	2.18E-04
6	Haddam Neck	1.05E-05	1.33E-04	4.02E-04
6	McGuire 1	2.14E-06	6.06E-05	2.13E-04
6	McGuire 2	2.14E-06	6.06E-05	2.13E-04
6	Millstone 3	6.01E-06	1.23E-04	4.19E-04
6	Salem 1	3.10E-06	6.22E-05	2.17E-04
6	Salem 2	3.10E-06	6.22E-05	2.17E-04
6	Seabrook	2.14E-06	6.07E-05	2.16E-04
6	Sequoyah 1	3.24E-06	6.22E-05	2.15E-04
6	Sequoyah 2	3.24E-06	6.22E-05	2.15E-04
6	Vogtle 1	2.13E-06	6.07E-05	2.14E-04
6	Vogtle 2	2.13E-06	6.07E-05	2.14E-04
6	Wolf Creek	2.79E-06	6.15E-05	2.14E-04
6	Zion 1	1.94E-06	6.07E-05	2.13E-04
6	Zion 2	1.94E-06	6.07E-05	2.13E-04

Table D-4. Plant-specific estimates of HPI unreliability (PRA-based) and 90% uncertainty based on the IPE failure rates for comparison to the HPI operational experience. (This set corresponds to the "IPE data for comparison to operating experience" plotted.)

HPI Design Class	Plant	5th Percentile of HPI IPE Unreliability	HPI IPE Unreliability Mean	95th Percentile of HPI IPE Unreliability
1	Arkansas Nuclear One 1	9.37E-04	1.11E-03	1.29E-03
1	Arkansas Nuclear One 2	8.79E-06	6.19E-05	2.10E-04
1	Calvert Cliffs 1	1.04E-04	1.67E-04	2.52E-04
1	Calvert Cliffs 2	1.04E-04	1.67E-04	2.52E-04
1	Davis-Besse	3.65E-04	5.46E-04	8.20E-04
1	Kewaunee	4.09E-05	8.48E-04	3.01E-03
1	Millstone 2		1.82E-04	
1	Palisades		1.92E-04	
1	Palo Verde 1	1.18E-05	1.96E-04	6.39E-04
1	Palo Verde 2	1.18E-05	1.96E-04	6.39E-04
1	Palo Verde 3	1.18E-05	1.96E-04	6.39E-04
1	Point Beach 1		3.65E-04	
1	Point Beach 2		3.65E-04	
1	Prairie Island 1		5.69E-04	
1	Prairie Island 2		5.69E-04	
1	San Onofre 2	4.18E-04	1.11E-03	2.36E-03
1	San Onofre 3	4.18E-04	1.11E-03	2.36E-03
1	St. Lucie 1	1.49E-04	3.61E-04	7.33E-04
1	St. Lucie 2	1.49E-04	3.61E-04	7.33E-04
1	Waterford 3	1.54E-04	9.53E-04	2.86E-03
2	Crystal River 3	3.56E-04	4.10E-04	4.70E-04
2	Fort Calhoun	3.06E-05	2.43E-04	7.62E-04
2	Ginna	1.93E-05	9.17E-05	2.52E-04
2	Oconee 1		3.18E-04	
2	Oconee 2		3.18E-04	
2	Oconee 3		3.18E-04	
2	Three Mile Island 1	1.89E-04	2.25E-04	2.66E-04
3	Beaver Valley 1	3.36E-04	9.73E-04	2.62E-03
3	Beaver Valley 2	8.90E-04	2.51E-03	5.82E-03
3	Farley 1	2.68E-04	4.24E-04	6.77E-04
3	Farley 2	2.68E-04	4.24E-04	6.77E-04
3	H.B. Robinson	4.64E-04	8.90E-04	1.53E-03
3	Maine Yankee	2.55E-04	7.10E-04	1.52E-03
3	North Anna 1	1.00E-10	5.02E-03	2.23E-02
3	North Anna 2	1.00E-10	5.02E-03	2.23E-02
3	Shearon Harris 1	1.78E-04	5.53E-04	1.26E-03

Table D-4. (continued).

HPI Design Class	Plant	5th Percentile of HPI IPE Unreliability	HPI IPE Unreliability Mean	95th Percentile of HPI IPE Unreliability
3	Summer 1		1.16E-04	
3	Surry 1	1.11E-03	4.14E-03	6.78E-03
3	Surry 2	1.11E-03	4.14E-03	6.78E-03
4	Turkey Point 3	1.88E-04	9.94E-04	1.66E-03
4	Turkey Point 4	1.88E-04	9.94E-04	1.66E-03
5	Indian Point 2	1.13E-03	2.27E-03	3.97E-03
5	Indian Point 3	8.84E-05	3.55E-04	9.38E-04
5	South Texas 1	8.76E-06	3.42E-05	7.87E-05
5	South Texas 2	8.76E-06	3.42E-05	7.87E-05
6	Braidwood 1		3.59E-08	
6	Braidwood 2		3.59E-08	
6	Byron 1		6.20E-09	
6	Byron 2		6.20E-09	
6	Callaway	2.81E-06	3.60E-06	5.55E-06
6	Catawba 1		1.10E-05	
6	Catawba 2		1.10E-05	
6	Comanche Peak 1		3.37E-06	
6	Comanche Peak 2		3.37E-06	
6	Cook 1	1.22E-07	2.15E-07	4.08E-07
6	Cook 2	1.22E-07	2.15E-07	4.08E-07
6	Diablo Canyon 1	3.04E-05	3.06E-05	3.11E-05
6	Diablo Canyon 2	3.04E-05	3.06E-05	3.11E-05
6	Haddam Neck		3.41E-05	
6	McGuire 1		1.11E-05	
6	McGuire 2		1.11E-05	
6	Millstone 3	7.68E-07	1.46E-05	5.45E-05
6	Salem 1	1.00E-05	1.02E-05	1.05E-05
6	Salem 2	1.00E-05	1.02E-05	1.05E-05
6	Seabrook	1.91E-07	8.16E-07	2.28E-06
6	Sequoyah 1	7.69E-07	1.27E-06	2.46E-06
6	Sequoyah 2	7.69E-07	1.27E-06	2.46E-06
6	Vogtle 1	1.10E-04	1.10E-04	1.10E-04
6	Vogtle 2	1.10E-04	1.10E-04	1.10E-04
6	Wolf Creek	1.08E-05	1.09E-05	1.09E-05
6	Zion 1		2.75E-08	
6	Zion 2		2.75E-08	

Table D-5. A listing of the pipe-segment cut sets (by reference plant in the six HPI design classes) contributing 0.1% or greater to HPI operational unreliability based on the 1987-1997 experience and a half-hour mission time.

HPI Design Class 1
System: Waterford
Mincut Upper Bound : 3.305E-04

Cut No.	CutSet %	Probability	Basic Event[a]	Probability
1	32.7	1.10E-04	WGS3-ALPHA-SI-FTS	3.60E-02
			WGS3-SI-PUMP-FTS	3.00E-03
2	28.4	9.40E-05	WGS3-ALPHA-SI-FTR	7.50E-02
			WGS3-SI-PUMP-FTR	1.20E-03
3	16	5.30E-05	WGS3-RWST-SUCT	5.30E-05
4	11.6	3.80E-05	WGS3-ALPHA-SI-INJ	1.20E-02
			WGS3-SI-HDR-INJ	3.20E-03
5	2.7	9.00E-06	WGS3-SI-FTS-PUMPA	3.00E-03
			WGS3-SI-FTS-PUMPB	3.00E-03
6	1.7	5.70E-06	WGS3-SI-FTS-PUMPA	3.00E-03
			WGS3-SI-MOOS-PUMPB	1.90E-03
7	1.7	5.70E-06	WGS3-SI-FTS-PUMPB	3.00E-03
			WGS3-SI-MOOS-PUMPA	1.90E-03
8	1.1	3.80E-06	WGS3-SI-FTR-PUMPA	1.20E-03
			WGS3-SI-FTS-PUMPB	3.00E-03
9	1.1	3.80E-06	WGS3-SI-FTR-PUMPB	1.20E-03
			WGS3-SI-FTS-PUMPA	3.00E-03
10	1	3.20E-06	WGS3-FTO-ACT-CHANLA	1.80E-03
			WGS3-FTO-ACT-CHANLB	1.80E-03
11	0.7	2.40E-06	WGS3-SI-FTR-PUMPA	1.20E-03
			WGS3-SI-MOOS-PUMPB	1.90E-03
12	0.7	2.40E-06	WGS3-SI-FTR-PUMPB	1.20E-03
			WGS3-SI-MOOS-PUMPA	1.90E-03
13	0.5	1.60E-06	WGS3-SI-FTR-PUMPA	1.20E-03
			WGS3-SI-FTR-PUMPB	1.20E-03
14	0.0	1.00E-09	WGS3-CKV-LOOPA-INJA	1.00E-03
			WGS3-CKV-LOOPA-INJB	1.00E-03
			WGS3-CKV-LOOPB-INJA	1.00E-03
15	0.0	1.00E-09	WGS3-CKV-LOOPA-INJA	1.00E-03
			WGS3-CKV-LOOPA-INJB	1.00E-03
			WGS3-CKV-LOOPB-INJB	1.00E-03
16	0.0	1.00E-09	WGS3-CKV-LOOPA-INJA	1.00E-03
			WGS3-CKV-LOOPB-INJA	1.00E-03
			WGS3-CKV-LOOPB-INJB	1.00E-03
17	0.0	1.00E-09	WGS3-CKV-LOOPA-INJB	1.00E-03
			WGS3-CKV-LOOPB-INJA	1.00E-03
			WGS3-CKV-LOOPB-INJB	1.00E-03

a. A description of the coding scheme of the basic event name is provided in Section D-3.

Table D-5. (continued).

HPI Design Class 2
System: Oconee
Mincut Upper Bound : 2.72E-04

Cut No.	CutSet %	Probability	Basic Event[a]	Probability
1	65.7	1.80E-04	NEE1-ALPHA-CC-INJ	5.60E-02
			NEE1-CC-HDR-INJ	3.20E-03
2	19.4	5.30E-05	NEE1-RWST-SUCT	5.30E-05
3	3.8	1.00E-05	NEE1-MOV-HDRA-INJ	3.20E-03
			NEE1-MOV-HDRB-INJ	3.20E-03
4	3.5	9.60E-06	NEE1-CC-FTS-PUMPC	3.00E-03
			NEE1-MOV-HDRA-INJ	3.20E-03
5	2.3	6.40E-06	NEE1-ALPHA-CC-FTR	5.10E-03
			NEE1-CC-PUMP-FTR	1.20E-03
6	2.2	6.10E-06	NEE1-CC-MOOS-PUMPC	1.90E-03
			NEE1-MOV-HDRA-INJ	3.20E-03
7	1.5	4.00E-06	NEE1-CC-FTR-PUMPC	1.20E-03
			NEE1-MOV-HDRA-INJ	3.20E-03
8	1.2	3.20E-06	NEE1-FTO-ACT-CHANLA	1.80E-03
			NEE1-FTO-ACT-CHANLB	1.80E-03
9	0.2	6.10E-07	NEE1-SLPHA-CC-FTS	6.30E-02
			NEE1-CC-PUMP-FTS	3.00E-03
			NEE1-MOV-HDRA-INJ	3.20E-03
10	0.1	2.40E-07	NEE1-ALPHA-CC-FTS	6.30E-02
			NEE1-CC-FTR-PUMPA	1.20E-03
			NEE1-CC-PUMP-FTS	3.00E-03
11	0.0	1.20E-08	NEE1-CC-FTR-PUMPA	1.20E-03
			NEE1-CC-FTS-PUMPB	3.00E-03
			NEE1-MOV-HDRB-INJ	3.20E-03
12	0.0	1.10E-08	NEE1-CC-FTR-PUMPA	1.20E-03
			NEE1-CC-FTS-PUMPB	3.00E-03
			NEE1-CC-FTS-PUMPC	3.00F-03
13	0.0	7.60E-09	NEE1-CC-FTR-PUMPA	1.20E-03
			NEE1-CC-MOOS-PUMPB	1.90E-03
			NEE1-MOV-HDRB-INJ	3.20E-03
14	0.0	7.10E-09	NEE1-CC-FTR-PUMPA	1.20E-03
			NEE1-CC-FTS-PUMPB	3.00E-03
			NEE1-CC-MOOS-PUMPC	1.90E-03
15	0.0	7.10E-09	NEE1-CC-FTR-PUMPA	1.20E-03
			NEE1-CC-FTS-PUMPC	3.00E-03
			NEE1-CC-MOOS-PUMPB	1.90E-03

a. A description of the coding scheme of the basic event name is provided in Section D-3.

Table D-5. (continued).

Cut No.	CutSet %	Probability	Basic Event[a]	Probability
16	0.0	5.00E-09	NEE1-CC-FTR-PUMPA	1.20E-03
			NEE1-CC-FTR-PUMPB	1.20E-03
			NEE1-MOV-HDRB-INJ	3.20E-03
17	0.0	4.70E-09	NEE1-CC-FTR-PUMPA	1.20E-03
			NEE1-CC-FTR-PUMPB	1.20E-03
			NEE1-CC-FTS-PUMPC	3.00E-03
18	0.0	4.70E-09	NEE1-CC-FTR-PUMPA	1.20E-03
			NEE1-CC-FTR-PUMPC	1.20E-03
			NEE1-CC-FTS-PUMPB	3.00E-03
19	0.0	3.20E-09	NEE1-CKV-LOOPA-INJA	1.00E-03
			NEE1-CKV-LOOPA-INJB	1.00E-03
			NEE1-MOV-HDRB-INJ	3.20E-03
20	0.0	3.20E-09	NEE1-CKV-LOOPB-INJA	1.00E-03
			NEE1-CKV-LOOPB-INJB	1.00E-03
			NEE1-MOV-HDRA-INJ	3.20E-03
21	0.0	3.00E-09	NEE1-CC-FTS-PUMPC	3.00E-03
			NEE1-CKV-LOOPA-INJA	1.00E-03
			NEE1-CKV-LOOPA-INJB	1.00E-03
22	0.0	3.00E-09	NEE1-CC-FTR-PUMPA	1.20E-03
			NEE1-CC-FTR-PUMPB	1.20E-03
			NEE1-CC-MOOS-PUMPC	1.90E-03
23	0.0	3.00E-09	NEE1-CC-FTR-PUMPA	1.20E-03
			NEE1-CC-FTR-PUMPC	1.20E-03
			NEE1-CC-MOOS-PUMPB	1.90E-03
24	0.0	2.00E-09	NEE1-CC-FTR-PUMPA	1.20E-03
			NEE1-CC-FTR-PUMPB	1.20E-03
			NEE1-CC-FTR-PUMPC	1.20E-03
25	0.0	1.90E-09	NEE1-CC-MOOS-PUMPC	1.90E-03
			NEE1-CKV-LOOPA-INJA	1.00E-03
			NEE1-CKV-LOOPA-INJB	1.00E-03
26	0.0	1.30E-09	NEE1-CC-FTR-PUMPC	1.20E-03
			NEE1-CKV-LOOPA-INJA	1.00E-03
			NEE1-CKV-LOOPA-INJB	1.00E-03

a. A description of the coding scheme of the basic event name is provided in Section D-3.

Table D-5. (continued).

HPI Design Class 3
System: Shearon Harris
Mincut Upper Bound : 4.627E-04

Cut No.	CutSet %	Probability	Basic Event[a]	Probability
1	38.7	1.80E-04	SHS1-ALPHA-CC-INJI	5.60E-02
			SHS1-CC-HDR-INJI	3.20E-03
2	38.7	1.80E-04	SHS1-ALPHA-CC-INJO	5.60E-02
			SHS1-CC-HDR-INJO	3.20E-03
3	11.5	5.30E-05	SHS1-RWST-SUCT	5.30E-05
4	4.3	2.00E-05	SHS1-ALPHA-CC-FTR	1.60E-02
			SHS1-CC-PUMP-FTR	1.20E-03
5	2.2	1.00E-05	SHS1-MOV-CC-HDR-INJAI	3.20E-03
			SHS1-MOV-CC-HDR-INJBI	3.20E-03
6	2.2	1.00E-05	SHS1-MOV-CC-HDR-INJAO	3.20E-03
			SHS1-MOV-CC-HDR-INJBO	3.20E-03
7	0.8	3.80E-06	SHS1-CC-FTR-PUMPA	1.20E-03
			SHS1-CC-FTS-PUMPB	3.00E-03
8	0.7	3.20E-06	SHS1-FTO-ACT-CHANLA	1.80E-03
			SHS1-FTO-ACT-CHANLB	1.80E-03
9	0.5	2.40E-06	SHS1-CC-FTR-PUMPA	1.20E-03
			SHS1-CC-MOOS-PUMPB	1.90E-03
10	0.3	1.60E-06	SHS1-CC-FTR-PUMPA	1.20E-03
			SHS1-CC-FTR-PUMPB	1.20E-03
11	0.0	1.00E-09	SHS1-CKV-LOOPA-INJ	1.00E-03
			SHS1-CKV-LOOPB-INJ	1.00E-03
			SHS1-CKV-LOOPC-INJ	1.00E-03
12	0.0	1.00E-09	SHS1-CKV-LOOPA-INJ	1.00E-003
			SHS1-CKV-LOOPB-INJ	1.00E-03
			SHS1-CKV-LPC-HDRB-INJ	1.00E-03
13	0.0	1.00E-09	SHS1-CKV-LOOPA-INJ	1.00E-03
			SHS1-CKV-LOOPC-INJ	1.00E-03
			SHS1-CKV-LPB-HDRB-INJ	1.00E-03
14	0.0	1.00E-09	SHS1-CKV-LOOPA-INJ	1.00E-03
			SHS1-CKV-LPB-HDRB-INJ	1.00E-03
			SHS1-CKV-LPC-HDRB-INJ	1.00E-03
15	0.0	1.00E-09	SHS1-CKV-LOOPB-INJ	1.00E-03
			SHS1-CKV-LOOPC-INJ	1.00E-03
			SHS1-CKV-LPA-HDRB-INJ	1.00E-03
16	0.0	1.00E-09	SHS1-CKV-LOOPB-INJ	1.00E-03
			SHS1-CKV-LPA-HDRB-INJ	1.00E-03
			SHS1-CKV-LPC-HDRB-INJ	1.00E-03
17	0.0	1.00E-09	SHS1-CKV-LOOPC-INJ	1.00E-03
			SHS1-CKV-LPA-HDRB-INJ	1.00E-03
			SHS1-CKV-LPB-HDRB-INJ	1.00E-03

a. A description of the coding scheme of the basic event name is provided in Section D-3.

Table D-5. (continued).

HPI Design Class 4
System: Turkey Point
Mincut Upper Bound : 2.717E-04

Cut No.	CutSet %	Probability	Basic Event[a]	Probability
1	66	1.80E-04	TPS3-ALPHA-SI-INJ	5.60E-02
			TPS3-SI-HDR-INJ	3.20E-03
2	15.5	4.20E-05	TPS3-ALPHA-SI-FTS	1.40E-02
			TPS3-SI-PUMP-FTS	3.00E-03
3	12.9	3.50E-05	TPS3-ALPHA-SI-FTR	2.80E-02
			TPS3-SI-PUMP-FTR	1.20E-03
4	3.8	1.00E-05	TPS3-MOV-CC-HDR-INJA	3.20E-03
			TPS3-MOV-CC-HDR-INJB	3.20E-03
5	1.2	3.20E-06	TPS3-FTO-ACT-CHANLA	1.80E-03
			TPS3-FTO-ACT-CHANLB	1.80E-03
6	0.1	1.60E-07	TPS3-RWST-SUCT3	5.30E-05
			TPS3-SI-FTS-PUMP4A	3.00E-03
7	0.1	1.60E-07	TPS3-RWST-SUCT3	5.30E-05
			TPS3-SI-FTS-PUMP4B	3.00E-03
8	0.1	1.60E-07	TPS3-RWST-SUCT4	5.30E-05
			TPS3-SI-FTS-PUMP3A	3.00E-03
9	0.1	1.60E-07	TPS3-RWST-SUCT4	5.30E-05
			TPS3-SI-FTS-PUMP3B	3.00E-03
10	0.0	1.00E-07	TPS3-RWST-SUCT3	5.30E-05
			TPS3-SI-MOOS-PUMP4A	1.90E-03
11	0.0	1.00E-07	TPS3-RWST-SUCT3	5.30E-05
			TPS3-SI-MOOS-PUMP4B	1.90E-03
12	0.0	1.00E-07	TPS3-RWST-SUCT4	5.30E-05
			TPS3-SI-MOOS-PUMP3A	1.90E-03
13	0.0	1.00E-07	TPS3-RWST-SUCT4	5.30E-05
			TPS3-SI-MOOS-PUMP3B	1.90E-03

a. A description of the coding scheme of the basic event name is provided in Section D-3.

Table D-5. (continued).

HPI Design Class 5
System: South Texas Project
Mincut Upper Bound : 2.633E-04

Cut No.	CutSet %	Probability	Basic Event[a]	Probability
1	40.1	1.10E-04	STN1-ALPHA-SI-INJ	3.30E-02
			STN1-SI-HDR-INJ	3.20E-03
2	20.5	5.40E-05	STN1-ALPHA-SI-FTS	1.80E-02
			STN1-SI-PUMP-FTS	3.00E-03
3	20.1	5.30E-05	STN1-RWST-SUCT	5.30E-05
4	19	5.00E-05	STN1-ALPHA-SI-FTR	4.00E-02
			STN1-SI-PUMP-FTR	1.20E-03
5	0.0	3.30E-08	STN1-MOV-LOOPA-INJ	3.20E-03
			STN1-MOV-LOOPB-INJ	3.20E-03
			STN1-MOV-LOOPC-INJ	3.20E-03
6	0.0	3.10E-08	STN1-MOV-LOOPA-INJ	3.20E-03
			STN1-MOV-LOOPB-INJ	3.20E-03
			STN1-SI-FTS-PUMPC	3.00E-03
7	0.0	3.10E-08	STN1-MOV-LOOPA-INJ	3.20E-03
			STN1-MOV-LOOPC-INJ	3.20E-03
			STN1-SI-FTS-PUMPB	3.00E-03
8	0.0	3.10E-08	STN1-MOV-LOOPB-INJ	3.20E-03
			STN1-MOV-LOOPC-INJ	3.20E-03
			STN1-SI-FTS-PUMPA	3.00E-03
9	0.0	2.90E-08	STN1-MOV-LOOPA-INJ	3.20E-03
			STN1-SI-FTS-PUMPB	3.00E-03
			STN1-SI-FTS-PUMPC	3.00E-03
10	0.0	2.90E-08	STN1-MOV-LOOPB-INJ	3.20E-03
			STN1-SI-FTS-PUMPA	3.00E-03
			STN1-SI-FTS-PUMPC	3.00E-03
11	0.0	2.90E-08	STN1-MOV-LOOPC-INJ	3.20E-03
			STN1-SI-FTS-PUMPA	3.00E-03
			STN1-SI-FTS-PUMPB	3.00E-03
12	0.0	2.70E-08	STN1-SI-FTS-PUMPA	3.00E-03
			STN1-SI-FTS-PUMPB	3.00E-03
			STN1-SI-FTS-PUMPC	3.00E-03
13	0.0	2.00E-08	STN1-MOV-LOOPA-INJ	3.20E-03
			STN1-MOV-LOOPB-INJ	3.20E-03
			STN1-SI-MOOS-PUMPC	1.90E-03
14	0.0	2.00E-08	STN1-MOV-LOOPA-INJ	3.20E-03
			STN1-MOV-LOOPC-INJ	3.20E-03
			STN1-SI-MOOS-PUMPB	1.90E-03
15	0.0	2.00E-08	STN1-MOV-LOOPB-INJ	3.20E-03
			SSTN1-MOV-LOOPC-INJ	3.20E-03
			STN1-SI-MOOS-PUMPA	1.90E-03
			STN1-MDP-FS-PUMPB	3.30E-03

a. A description of the coding scheme of the basic event name is provided in Section D-3.

Table D-5. (continued).

HPI design class 6
System: Braidwood
Mincut Upper Bound : 5.699E-05

Cut No.	CutSet %	Probability	Basic Event[a]	Probability
1	93	5.30E-05	BRS1-RWST-SUCT	5.30E-05
2	5.7	3.20E-06	BRS1-FTO-ACT-CHANLA	1.80E-03
			BRS1-FTO-ACT-CHANLB	1.80E-03
3	1	5.70E-07	BRS1-ALPHA-CC-INJ	5.60E-02
			BRS1-CC-HDR-INJ	3.20E-03
			BRS1-MOV-SI-HDR-INJ	3.20E-03
4	0.1	6.40E-08	BRS1-ALPHA-CC-FTR	1.60E-02
			BRS1-CC-PUMMP-FTR	1.20E-03
			BRS1-MOV-SI-HDR-INJ	3.20E-03
5	0.1	3.30E-08	BRS1-MOV-CC-HDR-INJA	3.20E-03
			BRS1-MOV-CC-HDR-INJB	3.20E-03
			BRS1-MOV-SI-HDR-INJ	3.20E-03
6	0.0	1.90E-08	BRS1-ALPHA-CC-INJ	5.60E-02
			BRS1-ALPHA-SI-FTS	3.60E-02
			BRS1-CC-HDR-INJ	3.20E-03
			BRS1-SI-PUMP-FTS	3.00E-03
7	0.0	1.70E-08	BRS1-ALPHA-CC-INJ	5.60E-02
			BRS1-ALPHA-SI-FTR	7.50E-02
			BRS1-CC-HDR-INJ	3.20E-03
			BRS1-SI-PUMP-FTR	1.20E-03
8	0.0	1.20E-08	BRS1-CC-FTR-PUMPA	1.20E-03
			BRS1-CC-FTS-PUMPB	3.00E-03
			BRS1-MOV-SI-HDR-INJ	3.20E-03
9	0.0	7.60E-09	BRS1-CC-FTR-PUMPA	1.20E-03
			BRS1-CC-MOOS-PUMPB	1.90E-03
			BRS1-MOV-SI-HDR-INJ	3.20E-03
10	0.0	5.00E-09	BRS1-CC-FTR-PUMPA	1.20E-03
			BRS1-CC-FTR-PUMPB	1.20E-03
			BRS1-MOV-SI-HDR-INJ	3.20E-03
11	0.0	2.20E-09	BRS1-ALPHA-CC-FTR	1.60E-02
			BRS1-ALPHA-SI-FTS	3.60E-02
			BRS1-CC-PUMP-FTR	1.20E-03
			BRS1-SI-PUMP-FTS	3.00E-03

a. A description of the coding scheme of the basic event name is provided in Section D-3.

Table D-5. (continued).

Cut No.	CutSet %	Probability	Basic Event[a]	Probability
12	0.0	1.90E-09	BRS1-ALPHA-CC-FTR	1.60E-02
			BRS1-ALPHA-SI-FTR	7.50E-02
			BRS1-CC-PUMP-FTR	1.20E-03
			BRS1-SI-PUMP-FTR	1.20E-03
13	0.0	1.60E-09	BRS1-ALPHA-CC-INJ	5.60E-02
			BRS1-CC-HDR-INJ	3.20E-03
			BRS1-SI-FTS-PUMPA	3.00E-03
			BRS1-SI-FTS-PUMPB	3.00E-03
14	0.0	1.10E-09	BRS1-ALPHA-SI-FTS	3.60E-02
			BRS1-MOV-CC-HDR-INJA	3.20E-03
			BRS1-MOV-CC-HDR-INJB	3.20E-03
			BRS1-SI-PUMP-FTS	3.00E-03
15	0.0	1.00E-09	BRS1-ALPHA-CC-INJ	5.60E-02
			BRS1-CC-HDR-INJ	3.20E-03
			BRS1-SI-FTS-PUMPA	3.00E-03
			BRS1-SI-MOOS-PUMPB	1.90E-03
16	0.0	1.00E-09	BRS1-ALPHA-CC-INJ	5.60E-02
			BRS1-CC-HDR-INJ	3.20E-03
			BRS1-SI-FTS-PUMPB	3.00E-03
			BRS1-SI-MOOS-PUMPA	1.90E-03

a. A description of the coding scheme of the basic event name is provided in Section D-3.

Table D-6. A listing of the cut sets (by reference plant in the six HPI design classes contributing 0.1% or greater to HPI unreliability) based on the IPE failure probabilities and a half-hour mission time.

HPI Design Class 1
System: Waterford
Mincut Upper Bound : 9.143E-04

Cut No.	CutSet %	Probability	Basic Event	Probability
1	89.3	8.20E-04	WGS3-MDP-CCF-FS	8.20E-04
2	2.6	2.40E-05	WGS3-MDP-FS-PUMPA	4.80E-03
			WGS3-MDP-MOOS-PUMPB	5.00E-03
3	2.6	2.40E-05	WGS3-MDP-FS-PUMPB	4.80E-03
			WGS3-MDP-MOOS-PUMPA	5.00E-03
4	2.5	2.30E-05	WGS3-MDP-FS-PUMPA	4.80E-03
			WGS3-MDP-FS-PUMPB	4.80E-03
5	0.8	7.20E-06	WGS3-MDP-CCF-FR	7.20E-06
6	0.2	2.00E-06	WGS3-MDP-MOOS-PUMPA	5.00E-03
			WGS3-MOV-CCF-DISB	4.10E-04
7	0.2	2.00E-06	WGS3-MDP-MOOS-PUMPB	5.00E-03
			WGS3-MOV-CCF-DISA	4.10E-04
8	0.2	2.00E-06	WGS3-MDP-FS-PUMPA	4.80E-03
			WGS3-MOV-CCF-DISB	4.10E-04
9	0.2	2.00E-06	WGS3-MDP-FS-PUMPB	4.80E-03
			WGS3-MOV-CCF-DISA	4.10E-04
10	0.1	7.50E-07	WGS3-CKV-DISA	1.50E-04
			WGS3-MDP-MOOS-PUMPB	5.00E-03
11	0.1	7.50E-07	WGS3-CKV-PUMPA	1.50E-04
			WGS3-MDP-MOOS-PUMPB	5.00E-03
12	0.1	7.50E-07	WGS3-CKV-PUMPB-DIS	1.50E-04
			WGS3-MDP-MOOS-PUMPA	5.00E-03
13	0.1	7.50E-07	WGS3-CKV-PUMPB-SUCT	1.50E-04
			WGS3-MDP-MOOS-PUMPA	5.00E-03
14	0.1	7.50E-07	WGS3-CKV-SUC1A	1.50E-04
			WGS3-MDP-MOOS-PUMPB	5.00E-03
15	0.1	7.50E-07	WGS3-CKV-SUC2A	1.50E-04
			WGS3-MDP-MOOS-PUMPB	5.00E-03
16	0.1	7.50E-07	WGS3-CKV-SUCB	1.50E-04
			WGS3-MDP-MOOS-PUMPA	5.00E-03
17	0.1	7.20E-07	WGS3-CKV-DISA	1.50E-04
			WGS3-MDP-FS-PUMPB	4.80E-03
18	0.1	7.20E-07	WGS3-CKV-PUMPA	1.50E-04
			WGS3-MDP-FS-PUMPB	4.80E-03
19	0.1	7.20E-07	WGS3-CKV-PUMPB-DIS	1.50E-04
			WGS3-MDP-FS-PUMPA	4.80E-03

Table D-6. (continued).

Cut No.	CutSet %	Probability	Basic Event	Probability
20	0.1	7.20E-07	WGS3-CKV-PUMPB-SUCT	1.50E-04
			WGS3-MDP-FS-PUMPA	4.80E-03
21	0.1	7.20E-07	WGS3-CKV-SUC1A	1.50E-04
			WGS3-MDP-FS-PUMPB	4.80E-03
22	0.1	7.20E-07	WGS3-CKV-SUC2A	1.50E-04
			WGS3-MDP-FS-PUMPB	4.80E-03
23	0.1	7.20E-07	WGS3-CKV-SUCB	1.50E-04
			WGS3-MDP-FS-PUMPA	4.80E-03

Table D-6. (continued).

HPI design class 2
System: Oconee
Mincut Upper Bound : 3.177E-04

Cut No.	CutSet %	Probability	Basic Event	Probability
1	85	2.70E-04	NEE1-MOV-CCF-SUCT	2.70E-04
2	8.2	2.60E-05	NEE1-MDP-MOOS-PUMPC	6.50E-03
			NEE1-MOV-CC-DISA	4.00E-03
3	5	1.60E-05	NEE1-MOV-CC-SUCA	4.00E-03
			NEE1-MOV-CC-SUCB	4.00E-03
4	0.4	1.30E-06	NEE1-CKV-HDRA-INJ	2.00E-04
			NEE1-MDP-MOOS-PUMPC	6.50E-03
5	0.3	8.40E-07	NEE1-MDP-FS-PUMPC	2.10E-04
			NEE1-MOV-CC-DISA	4.00E-03
6	0.3	8.00E-07	NEE1-CKV-DISA	2.00E-04
			NEE1-MOV-CC-SUCB	4.00E-03
7	0.3	8.00E-07	NEE1-CKV-HDRB-INJ	2.00E-04
			NEE1-MOV-CC-DISA	4.00E-03
8	0.3	8.00E-07	NEE1-CKV-PUMPC	2.00E-04
			NEE1-MOV-CC-DISA	4.00E-03
9	0.3	8.00E-07	NEE1-CKV-SUCB	2.00E-04
			NEE1-MOV-CC-SUCA	4.00E-03

Table D-6. (continued).

HPI design class 3
System: Shearon Harris
Mincut Upper Bound : 5.506E-04

Cut No.	CutSet %	Probability	Basic Event	Probability
1	50.9	2.80E-04	SHS1-CKV-RWST-SUCT	2.80E-04
2	13.6	7.50E-05	SHS1-MOV-CCF-BITI	7.50E-05
3	13.6	7.50E-05	SHS1-MOV-CCF-BITO	7.50E-05
4	13.6	7.50E-05	SHS1-MOV-CCF-SUCT	7.50E-05
5	3.2	1.80E-05	SHS1-CKV-DIS-PUMPA	2.80E-04
			SHS1-MDP-MOOS-PUMPB	6.30E-02
6	1.6	9.00E-06	SHS1-MOV-CC-SUCTA	3.00E-03
			SHS1-MOV-CC-SUCTB	3.00E-03
7	1.6	9.00E-06	SHS1-MOV-DIS-BITIA	3.00E-03
			SHS1-MOV-DIS-BITIB	3.00E-03
8	1.6	9.00E-06	SHS1-MOV-DIS-BITOA	3.00E-03
			SHS1-MOV-DIS-BITOB	3.00E-03
9	0.1	3.90E-07	SHS1-CKV-DIS-PUMPA	2.80E-04
			SHS1-MDP-FS-PUMPB	1.40E-03
10	0.1	3.50E-07	SHS1-MDP-FR-PUMPA	5.50E-06
			SHS1-MDP-MOOS-PUMPB	6.30E-02
11	0.1	2.60E-07	SHS1-MDP-CCF-FR	2.60E-07
12	0.0	7.80E-08	SHS1-CKV-DIS-PUMPA	2.80E-04
			SHS1-CKV-DIS-PUMPB	2.80E-04

Table D-6. (continued).

HPI design class 4
System: Turkey Point
Mincut Upper Bound : 5.764E-04

Cut No.	CutSet %	Probability	Basic Event	Probability
1	70.8	4.10E-04	TPS3-MOV-CCF-DIS	4.10E-04
2	4.5	2.60E-05	TPS3-MOV-CC-INJ3A	5.10E-03
			TPS3-MOV-CC-INJ3B	5.10E-03
3	1.7	9.80E-06	TPS3-MDP-CCF-FR3	7.90E-04
			TPS3-MDP-MOOS-PUMP4A	1.20E-02
4	1.7	9.80E-06	TPS3-MDP-CCF-FR3	7.90E-04
			TPS3-MDP-MOOS-PUMP4B	1.20E-02
5	1.7	9.80E-06	TPS3-MDP-CCF-FR4	7.90E-04
			TPS3-MDP-MOOS-PUMP3A	1.20E-02
6	1.7	9.80E-06	TPS3-MDP-CCF-FR4	7.90E-04
			TPS3-MDP-MOOS-PUMP3B	1.20E-02
7	1.3	7.40E-06	TPS3-MDP-CCF-FR3	7.90E-04
			TPS3-MDP-FR-PUMP4A	9.30E-03
8	1.3	7.40E-06	TPS3-MDP-CCF-FR3	7.90E-04
			TPS3-MDP-FR-PUMP4B	9.30E-03
9	1.3	7.40E-06	TPS3-MDP-CCF-FR4	7.30E-04
			TPS3-MDP-FR-PUMP3A	9.30E-03
10	1.3	7.40E-06	TPS3-MDP-CCF-FR4	7.90E-04
			TPS3-MDP-FR-PUMP3B	9.30E-03
11	0.8	4.90E-06	TPS3-MDP-CCF-FS3	3.90E-04
			TPS3-MDP-MOOS-PUMP4A	1.20E-02
12	0.8	4.90E-06	TPS3-MDP-CCF-FS3	3.90E-04
			TPS3-MDP-MOOS-PUMP4B	1.20E-02
13	0.8	4.90E-06	TPS3-MDP-CCF-FS4	3.90E-04
			TPS3-MDP-MOOS-PUMP3A	1.20E-02
14	0.8	4.90E-06	TPS3-MDP-CCF-FS4	3.90E-04
			TPS3-MDP-MOOS-PUMP3B	1.20E-02
15	0.6	3.60E-06	TPS3-MDP-CCF-FS3	3.90E-04
			TPS3-MDP-FR-PUMP4A	9.30E-03
16	0.6	3.60E-06	TPS3-MDP-CCF-FS3	3.90E-04
			TPS3-MDP-FR-PUMP4B	9.30E-03
17	0.6	3.60E-06	TPS3-MDP-CCF-FS4	3.90E-04
			TPS3-MDP-FR-PUMP3A	9.30E-03

Table D-6. (continued).

Cut No.	CutSet %	Probability	Basic Event	Probability
18	0.6	3.60E-06	TPS3-MDP-CCF-FS4	3.90E-04
			TPS3-MDP-FR-PUMP3B	9.30E-03
19	0.3	1.80E-06	TPS3-MDP-CCF-FR3	7.90E-04
			TPS3-MDP-FS-PUMP4A	2.30E-03
20	0.3	1.80E-06	TPS3-MDP-CCF-FR3	7.90E-04
			TPS3-MDP-FS-PUMP4B	2.30E-03
21	0.3	1.80E-06	TPS3-MDP-CCF-FR4	7.90E-04
			TPS3-MDP-FS-PUMP3A	2.30E-03
22	0.3	1.80E-06	TPS3-MDP-CCF-FR4	7.90E-04
			TPS3-MDP-FS-PUMP3B	2.30E-03
23	0.2	1.10E-06	TPS3-MDP-FR-PUMP3A	9.30E-03
			TPS3-MDP-FR-PUMP3B	9.30E-03
			TPS3-MDP-MOOS-PUMP4A	1.20E-02
24	0.2	1.10E-06	TPS3-MDP-FR-PUMP3A	9.30E-03
			TPS3-MDP-FR-PUMP3B	9.30E-03
			TPS3-MDP-MOOS-PUMP4B	1.20E-02
25	0.2	1.10E-06	TPS3-MDP-FR-PUMP3A	9.30E-03
			TPS3-MDP-FR-PUMP4A	9.30E-03
			TPS3-MDP-MOOS-PUMP3B	1.20E-02
26	0.2	1.10E-06	TPS3-MDP-FR-PUMP3A	9.30E-03
			TPS3-MDP-FR-PUMP4A	9.30E-03
			TPS3-MDP-MOOS-PUMP4B	1.20E-02
27	0.2	1.10E-06	TPS3-MDP-FR-PUMP3A	9.30E-03
			TPS3-MDP-FR-PUMP4B	9.30E-03
			TPS3-MDP-MOOS-PUMP3B	1.20E-02
28	0.2	1.10E-06	TPS3-MDP-FR-PUMP3A	9.30E-03
			TPS3-MDP-FR-PUMP4B	9.30E-03
			TPS3-MDP-MOOS-PUMP4A	1.20E-02
29	0.2	1.10E-06	TPS3-MDP-FR-PUMP3B	9.30E-03
			TPS3-MDP-FR-PUMP4A	9.30E-03
			TPS3-MDP-MOOS-PUMP3A	1.20E-02
30	0.2	1.10E-06	TPS3-MDP-FR-PUMP3B	9.30E-03
			TPS3-MDP-FR-PUMP4A	9.30E-03
			TPS3-MDP-MOOS-PUMP4B	1.20E-02
31	0.2	1.10E-06	TPS3-MDP-FR-PUMP3B	9.30E-03
			TPS3-MDP-FR-PUMP4B	9.30E-03
			TPS3-MDP-MOOS-PUMP3A	1.20E-02

Table D-6. (continued).

Cut No.	CutSet %	Probability	Basic Event	Probability
32	0.2	1.10E-06	TPS3-MDP-FR-PUMP3B	9.30E-03
			TPS3-MDP-FR-PUMP4B	9.30E-03
			TPS3-MDP-MOOS-PUMP4A	1.20E-02
33	0.2	1.10E-06	TPS3-MDP-FR-PUMP4A	9.30E-03
			TPS3-MDP-FR-PUMP4B	9.30E-03
			TPS3-MDP-MOOS-PUMP3A	1.20E-02
34	0.2	1.10E-06	TPS3-MDP-FR-PUMP4A	9.30E-03
			TPS3-MDP-FR-PUMP4B	9.30E-03
			TPS3-MDP-MOOS-PUMP3B	1.20E-02
35	0.2	9.00E-07	TPS3-MDP-CCF-FS3	3.90E-04
			TPS3-MDP-FS-PUMP4A	2.30E-03
36	0.2	9.00E-07	TPS3-MDP-CCF-FS3	3.90E-04
			TPS3-MDP-FS-PUMP4B	2.30E-03
37	0.2	9.00E-07	TPS3-MDP-CCF-FS4	3.90E-04
			TPS3-MDP-FS-PUMP3A	2.30E-03
38	0.2	9.00E-07	TPS3-MDP-CCF-FS4	3.90E-04
			TPS3-MDP-FS-PUMP3B	2.30E-03
39	0.1	8.00E-07	TPS3-MDP-FR-PUMP3A	9.30E-03
			TPS3-MDP-FR-PUMP3B	9.30E-03
			TPS3-MDP-FR-PUMP4A	9.30E-03
40	0.1	8.00E-07	TPS3-MDP-FR-PUMP3A	9.30E-03
			TPS3-MDP-FR-PUMP3B	9.30E-03
			TPS3-MDP-FR-PUMP4B	9.30E-03
41	0.1	8.00E-07	TPS3-MDP-FR-PUMP3A	9.30E-03
			TPS3-MDP-FR-PUMP4A	9.30E-03
			TPS3-MDP-FR-PUMP4B	9.30E-03
42	0.1	8.00E-07	TPS3-MDP-FR-PUMP3B	9.30E-03
			TPS3-MDP-FR-PUMP4A	9.30E-03
			TPS3-MDP-FR-PUMP4B	9.30E-03

Table D-6. (continued).

HPI design class 5
System: South Texas Project
Mincut Upper Bound : 3.171E-05

Cut No.	CutSet %	Probability	Basic Event	Probability
1	96.8	3.10E-05	STN1-MDP-CCF-FS	3.10E-05
2	2.7	8.50E-07	STN1-MDP-CCF-FR	8.50E-07
3	0.1	3.60E-08	STN1-MDP-FS-PUMPA	3.30E-03
			STN1-MDP-FS-PUMPB	3.30E-03
			STN1-MDP-FS-PUMPC	3.30E-03
4	0.0	1.30E-08	STN1-MDP-FS-PUMPA	3.30E-03
			STN1-MDP-FS-PUMPB	3.30E-03
			STN1-MDP-MOOS-PUMPC	1.20E-03
5	0.0	1.30E-08	STN1-MDP-FS-PUMPA	3.30E-03
			STN1-MDP-FS-PUMPC	3.30E-03
			STN1-MDP-MOOS-PUMPB	1.20E-03
6	0.0	1.30E-08	STN1-MDP-FS-PUMPB	3.30E-03
			STN1-MDP-FS-PUMPC	3.30E-03
			STN1-MDP-MOOS-PUMPA	1.20E-03
7	0.0	2.90E-09	STN1-CKV-DIS-PUMPA	2.70E-04
			STN1-MDP-FS-PUMPB	3.30E-03
			STN1-MDP-FS-PUMPC	3.30E-03
8	0.0	2.90E-09	STN1-CKV-DIS-PUMPB	2.70E-04
			STN1-MDP-FS-PUMPA	3.30E-03
			STN1-MDP-FS-PUMPC	3.30E-03
9	0.0	2.90E-09	STN1-CKV-DIS-PUMPC	2.70E-04
			STN1-MDP-FS-PUMPA	3.30E-03
			STN1-MDP-FS-PUMPB	3.30E-03
10	0.0	2.90E-09	STN1-CKV-LPA-INJ1A	2.70E-04
			STN1-MDP-FS-PUMPB	3.30E-03
			STN1-MDP-FS-PUMPC	3.30E-03
11	0.0	2.90E-09	STN1-CKV-LPA-INJ2A	2.70E-04
			STN1-MDP-FS-PUMPB	3.30E-03
			STN1-MDP-FS-PUMPC	3.30E-03
12	0.0	2.90E-09	STN1-CKV-LPB-INJ1B	2.70E-04
			STN1-MDP-FS-PUMPA	3.30E-03
			STN1-MDP-FS-PUMPC	3.30E-03
13	0.0	2.90E-09	STN1-CKV-LPB-INJ2B	2.70E-04
			STN1-MDP-FS-PUMPA	3.30E-03
			STN1-MDP-FS-PUMPC	3.30E-03

Table D-6. (continued).

Cut No.	CutSet %	Probability	Basic Event	Probability
14	0.0	2.90E-09	STN1-CKV-LPC-INJ1C	2.70E-04
			STN1-MDP-FS-PUMPA	3.30E-03
			STN1-MDP-FS-PUMPB	3.30E-03
15	0.0	2.90E-09	STN1-CKV-LPC-INJ2C	2.70E-04
			STN1-MDP-FS-PUMPA	3.30E-03
			STN1-MDP-FS-PUMPB	3.30E-03
16	0.0	2.90E-09	STN1-CKV-SUC-PUMPA	2.70E-04
			STN1-MDP-FS-PUMPB	3.30E-03
			STN1-MDP-FS-PUMPC	3.30E-03
17	0.0	2.90E-09	STN1-CKV-SUC-PUMPB	2.70E-04
			STN1-MDP-FS-PUMPA	3.30E-03
			STN1-MDP-FS-PUMPC	3.30E-03
18	0.0	2.90E-09	STN1-CKV-SUC-PUMPC	2.70E-04
			STN1-MDP-FS-PUMPA	3.30E-03
			STN1-MDP-FS-PUMPB	3.30E-03

Table D-6. (continued).

HPI design class 6
System: Braidwood
Mincut Upper Bound: 3.585E-08

Cut No.	CutSet %	Probability	Basic Event	Probability
1	27.9	1.00E-08	BRS1-CKV-CH-DIS	1.00E-04
			BRS1-CKV-SI-SUCT	1.00E-04
2	27.9	1.00E-08	BRS1-CKV-CH-SUCT	1.00E-04
			BRS1-CKV-SI-SUCT	1.00E-04
3	5.9	2.10E-09	BRS1-CKV-CH-DIS	1.00E-04
			BRS1-MDP-CCF-SI-START	2.10E-05
4	5.9	2.10E-09	BRS1-CKV-CH-SUCT	1.00E-04
			BRS1-MDP-CCF-SI-START	2.10E-05
5	4.2	1.50E-09	BRS1-CKV-SI-SUCT	1.00E-04
			BRS1-MOV-CCF-CH-DIS	1.50E-05
6	4.2	1.50E-09	BRS1-CKV-SI-SUCT	1.00E-04
			BRS1-MOV-CCF-CH-SUCT	1.50E-05
7	2.5	9.00E-10	BRS1-CKV-CH-DIS	1.00E-04
			BRS1-MDP-FS-SI-PUMPA	3.00E-03
			BRS1-MDP-FS-SI-PUMPB	3.00E-03
8	2.5	9.00E-10	BRS1-CKV-CH-SUCT	1.00E-04
			BRS1-MDP-FS-SI-PUMPA	3.00E-03
			BRS1-MDP-FS-SI-PUMPB	3.00E-03
9	2.2	8.0E-10	BRSI-RWST-SUCT	8.0E-10
10	1.6	5.70E-10	BRS1-CKV-CH-DIS	1.00E-04
			BRS1-MDP-FS-SI-PUMPA	3.00E-03
			BRS1-MDP-MOOS-SI-PUMPB	1.90E-03
11	1.6	5.70E-10	BRS1-CKV-CH-DIS	1.00E-04
			BRS1-MDP-FS-SI-PUMPB	3.00E-03
			BRS1-MDP-MOOS-SI-PUMPA	1.90E-03
12	1.6	5.70E-10	BRS1-CKV-CH-SUCT	1.00E-04
			BRS1-MDP-FS-SI-PUMPA	3.00E-03
			BRS1-MDP-MOOS-SI-PUMPB	1.90E-03
13	1.6	5.70E-10	BRS1-CKV-CH-SUCT	1.00E-04
			BRS1-MDP-FS-SI-PUMPB	3.00E-03
			BRS1-MDP-MOOS-SI-PUMPA	1.90E-03
14	1.1	3.90E-10	BRS1-CKV-CH-DIS	1.00E-04
			BRS1-MDP-CCF-SI-RUN	3.90E-06

Table D-6. (continued).

Cut No.	CutSet %	Probability	Basic Event	Probability
15	1.1	3.90E-10	BRS1-CKV-CH-SUCT	1.00E-04
			BRS1-MDP-CCF-SI-RUN	3.903-06
16	0.9	3.20E-10	BRS1-MDP-CCF-SI-START	2.10E-05
			BRS1-MOV-CCF-CH-DIS	1.50E-05
17	0.9	3.20E-10	BRS1-MDP-CCF-SI-START	2.10E-05
			BRS1-MOV-CCF-CH-SUCT	1.50E-05
18	0.5	1.70E-10	BRS1-CKV-CH-DIS	1.00E-04
			BRS1-MDP-FR-SI-PUMPA	5.50E-04
			BRS1-MDP-FS-SI-PUMPB	3.00E-03
19	0.5	1.70E-10	BRS1-CKV-CH-DIS	1.00E-04
			BRS1-MDP-FR-SI-PUMPB	5.50E-04
			BRS1-MDP-FS-SI-PUMPA	3.00E-03
20	0.5	1.70E-10	BRS1-CKV-CH-SUCT	1.00E-04
			BRS1-MDP-FR-SI-PUMPA	5.50E-04
			BRS1-MDP-FS-SI-PUMPB	3.00E-03
21	0.5	1.70E-10	BRS1-CKV-CH-SUCT	1.00E-04
			BRS1-MDP-FR-SI-PUMPB	5.50E-04
			BRS1-MDP-FS-SI-PUMPA	3.00E-03
22	0.4	1.40E-10	BRS1-MDP-FS-SI-PUMPA	3.00E-03
			BRS1-MDP-FS-SI-PUMPB	3.00E-03
			BRS1-MOV-CCF-CH-DIS	1.50E-05
23	0.4	1.40E-10	BRS1-MDP-FS-SI-PUMPA	3.00E-03
			BRS1-MDP-FS-SI-PUMPB	3.00E-03
			BRS1-MOV-CCF-CH-SUCT	1.50E-05
24	0.3	1.00E-10	BRS1-CKV-CH-DIS	1.00E-04
			BRS1-MDP-FR-SI-PUMPA	5.50E-04
			BRS1-MDP-MOOS-SI-PUMPB	1.90E-03
25	0.3	1.00E-10	BRS1-CKV-CH-DIS	1.00E-04
			BRS1-MDP-FR-SI-PUMPB	5.50E-04
			BRS1-MDP-MOOS-SI-PUMPA	1.90E-03
26	0.3	1.00E-10	BRS1-CKV-CH-SUCT	1.00E-04
			BRS1-MDP-FR-SI-PUMPA	5.50E-04
			BRS1-MDP-MOOS-SI-PUMPB	1.90E-03
27	0.3	1.00E-10	BRS1-CKV-CH-SUCT	1.00E-04
			BRS1-MDP-FR-SI-PUMPB	5.50E-04
			BRS1-MDP-MOOS-SI-PUMPA	1.90E-03

Table D-6. (continued).

Cut No.	CutSet %	Probability	Basic Event	Probability
28	0.2	8.60E-11	BRS1-MDP-FS-SI-PUMPA	3.00E-03
			BRS1-MDP-MOOS-SI-PUMPB	1.90E-03
			BRS1-MOV-CCF-CH-DIS	1.50E-05
29	0.2	8.60E-11	BRS1-MDP-FS-SI-PUMPA	3.00E-03
			BRS1-MDP-MOOS-SI-PUMPB	1.90E-03
			BRS1-MOV-CCF-CH-SUCT	1.50E-05
30	0.2	8.60E-11	BRS1-MDP-FS-SI-PUMPB	3.00E-03
			BRS1-MDP-MOOS-SI-PUMPA	1.90E-03
			BRS1-MOV-CCF-CH-DIS	1.50E-05
31	0.2	8.60E-11	BRS1-MDP-FS-SI-PUMPB	3.00E-03
			BRS1-MDP-MOOS-SI-PUMPA	1.90E-03
			BRS1-MOV-CCF-CH-SUCT	1.50E-05
32	0.2	5.80E-11	BRS1-MDP-CCF-SI-RUN	3.90E-06
			BRS1-MOV-CCF-CH-DIS	1.50E-05
33	0.2	5.80E-11	BRS1-MDP-CCF-SI-RUN	3.90E-06
			BRS1-MOV-CCF-CH-SUCT	1.50E-05
34	0.1	3.00E-11	BRS1-CKV-CH-DIS	1.00E-04
			BRS1-MDP-FR-SI-PUMPA	5.50E-04
			BRS1-MDP-FR-SI-PUMPB	5.50E-04
35	0.1	3.00E-11	BRS1-CKV-CH-SUCT	1.00E-04
			BRS1-MDP-FR-SI-PUMPA	5.50E-04
			BRS1-MDP-FR-SI-PUMPB	5.50E-04
36	0.1	3.00E-11	BRS1-CKV-CH-DIS	1.00E-04
			BRS1-CKV-SI-PUMPA	1.00E-04
			BRS1-MDP-FS-SI-PUMPB	3.00E-03
37	0.1	3.00E-11	BRS1-CKV-CH-DIS	1.00E-04
			BRS1-CKV-SI-PUMPB	1.00E-04
			BRS1-MDP-FS-SI-PUMPA	3.00E-03
38	0.1	3.00E-11	BRS1-CKV-CH-SUCT	1.00E-04
			BRS1-CKV-SI-PUMPA	1.00E-04
			BRS1-MDP-FS-SI-PUMPB	3.00E-03
39	0.1	3.00E-11	BRS1-CKV-CH-SUCT	1.00E-04
			BRS1-CKV-SI-PUMPB	1.00E-04
			BRS1-MDP-FS-SI-PUMPA	3.00E-03
40	0.1	2.50E-11	BRS1-MDP-FR-SI-PUMPA	5.50E-04
			BRS1-MDP-FS-SI-PUMPB	3.00E-03
			BRS1-MOV-CCF-CH-DIS	1.50E-05

Table D-6. (continued).

Cut No.	CutSet %	Probability	Basic Event	Probability
41	0.1	2.50E-11	BRS1-MDP-FR-SI-PUMPA	5.50E-04
			BRS1-MDP-FS-SI-PUMPB	3.00E-03
			BRS1-MOV-CCF-CH-SUCT	1.50E-05
42	0.1	2.50E-11	BRS1-MDP-FR-SI-PUMPB	5.50E-04
			BRS1-MDP-FS-SI-PUMPA	3.00E-03
			BRS1-MOV-CCF-CH-DIS	1.50E-05
43	0.1	2.50E-11	BRS1-MDP-FR-SI-PUMPB	5.50E-04
			BRS1-MDP-FS-SI-PUMPA	3.00E-03
			BRS1-MOV-CCF-CH-SUCT	1.50E-05
44	0.1	2.40E-11	BRS1-CKV-CH-PUMPA	1.00E-04
			BRS1-CKV-SI-SUCT	1.00E-04
			BRS1-MDP-MOOS-CH-PUMPB	2.40E-03
45	0.1	1.90E-11	BRS1-CKV-CH-DIS	1.00E-04
			BRS1-CKV-SI-PUMPA	1.00E-04
			BRS1-MPD-MOOS-SI-PUMPB	1.90E-03
46	0.1	1.90E-11	BRS1-CKV-CH-DIS	1.00E-04
			BRS1-CKV-SI-PUMPB	1.00E-04
			BRS1-MDP-MOOS-SI-PUMPA	1.90E-03
47	0.1	1.90E-11	BRS1-CKV-CH-SUCT	1.00E-04
			BRS1-CKV-SI-PUMPA	1.00E-04
			BRS1-MDP-MOOS-SI-PUMPB	1.90E-03
48	0.1	1.90E-11	BRS1-CKV-CH-SUCT	1.00E-04
			BRS1-CKV-SI-PUMPB	1.00E-04
			BRS1-MDP-MOOS-SI-PUMPA	1.90E-03
49	0.1	1.70E-11	BRS1-CKV-CH-PUMPA	1.00E-04
			BRS1-CKV-SI-SUCT	1.00E-04
			BRS1-MDP-FS-CH-PUMPB	1.70E-03

D-4. EFFECT OF CALENDAR YEAR AND LOW-POWER LICENSE DATE TOGETHER

The body of this report plotted the frequency of certain events against calendar year, and also against plant low-power license date. Such plots were shown for all SI actuations, for automatic and manual actuations, and for HPI failure events. In each of these cases the fitted frequency was a function of two factors, but each plot showed only the effect of one factor, calendar year or low-power license date; the other factor was ignored when the plot was constructed. A more accurate calculation fits the frequency as a function of both factors simultaneously, using equation (A-1) or (A-2) in Appendix A. This could be graphed in three-dimensional space by showing the fitted frequency as a surface, a function of both calendar year and low-power license year. Alternatively, cross sections of the surface can be plotted in two dimensions, plotting fitted frequency against calendar year, for selected values of low-power license year. Such plots are given here.

Figure D-2 shows a plot for the fitted frequency of all SI actuations. The frequency is the mean number of events per reactor-calendar-year.

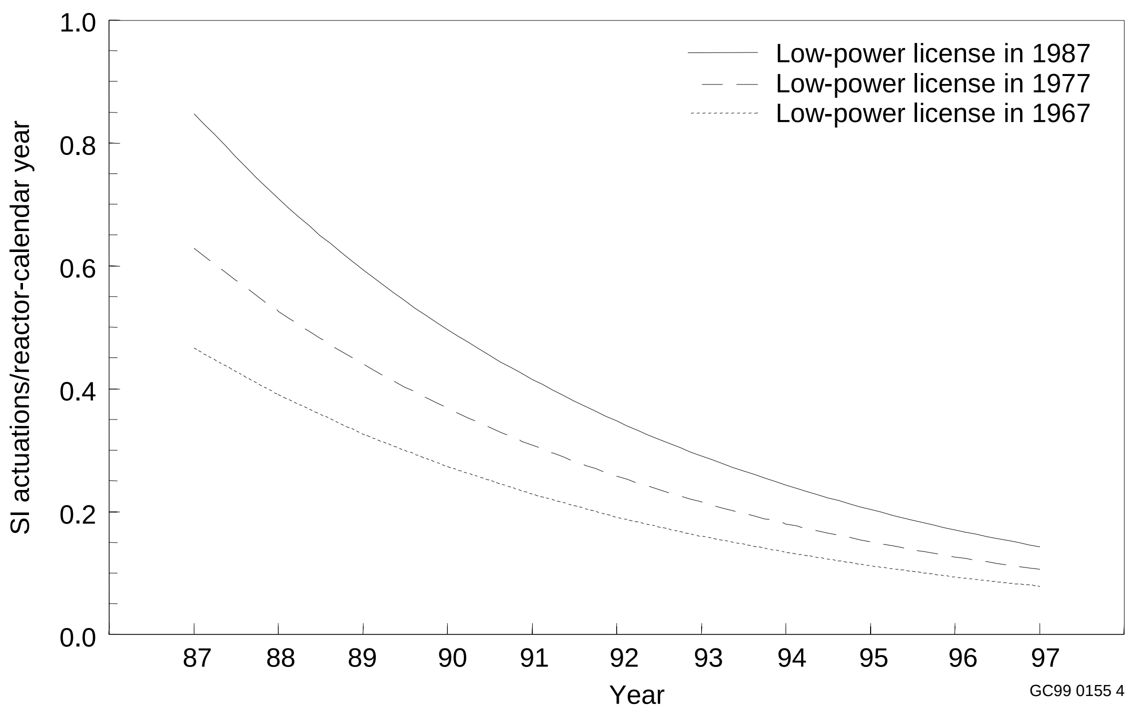


Figure D-2. Fitted frequency (events per reactor-calendar-year) of all SI actuations, as a function of calendar year, for plants with three assumed low-power license years.

Figure D-3 shows the same type of plot for the frequency of automatic and manual SI actuations. This frequency differs from the previous plot in two small ways. First, inadvertent and spurious actuations are excluded. Second, the frequency is defined as events per reactor-critical-year, not per reactor-calendar-year, because most automatic and manual SI actuations occurred when the reactor was critical.

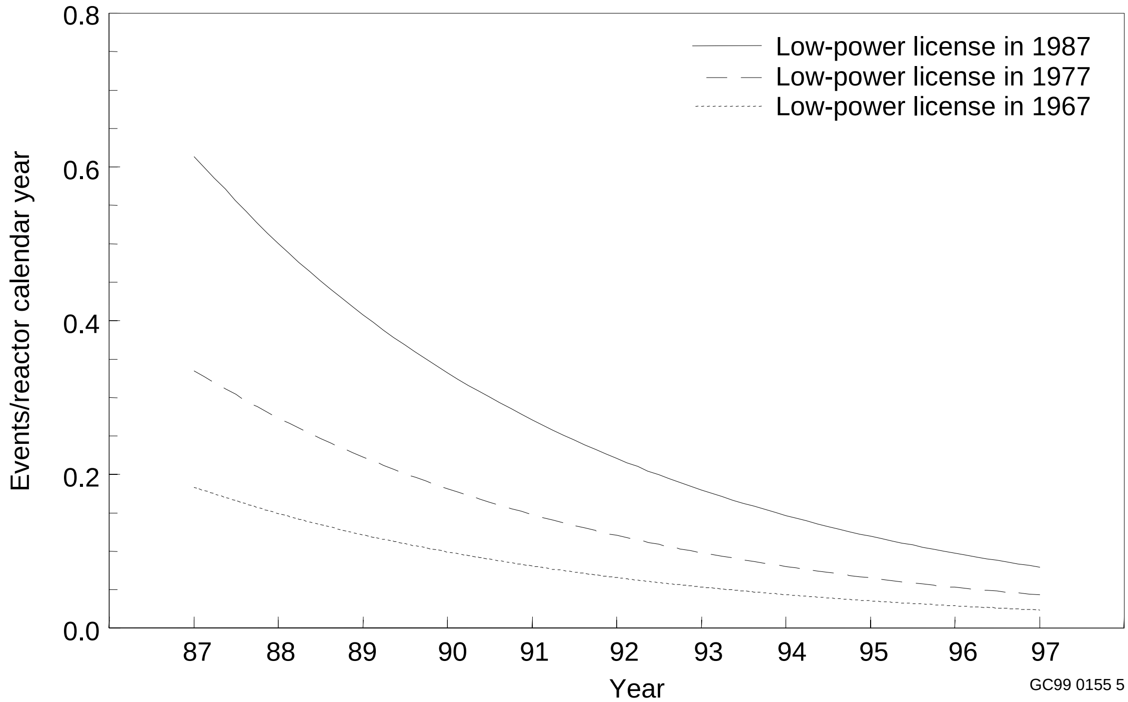


Figure D-3. Fitted frequency (events per reactor-critical-year) of all automatic and manual SI actuations, as a function of calendar year, for plants with three assumed low-power license years.

Finally, Figure D-4 shows the fitted frequency of HPI failure events, as a function of calendar year, for plants of three assumed low-power license years. When the data were analyzed, plant-specific differences were seen. Those plant-specific effects are not shown here. However, the plot must be interpreted as showing industry averages, not corresponding to any particular individual plants.

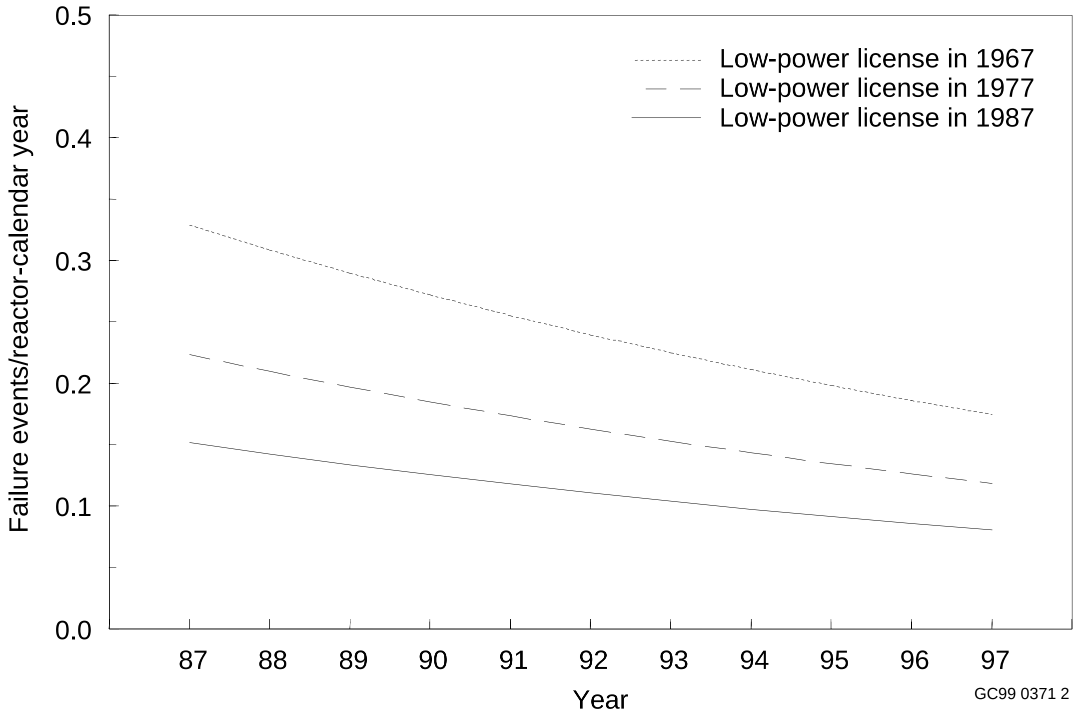


Figure D-4. Fitted frequency (events per reactor-calendar-year) of all HPI failure events, as a function of calendar year, for plants with three assumed low-power license years.