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ABSTRACT

This report documents an analysis of the safety-related performance of the auxiliary/emergency feedwater (AFW) system at United States commercial pressurized water reactor plants during the period 1987–1995. Both a risk-based analysis and an engineering analysis of trends and patterns were performed on data from AFW system operational events to provide insights into the performance of the AFW system throughout the industry and at a plant-specific level. Comparisons were made to probabilistic risk assessments and individual plant evaluations for 72 plants to indicate where operational data either support or fail to support the assumptions, models, and data used to develop the AFW system unreliability estimates.

Job Code E8246—Technical Assistance in Reliability and Risk Analysis

CONTENTS

LIST OF FIGURES

LIST OF TABLES

EXECUTIVE SUMMARY

This report presents a performance analysis of auxiliary feedwater (AFW) systems at 72 United States commercial pressurized water reactors (PWRs). The evaluation is based on the operating experience from 1987 through 1995, 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 assumptions, models, and data used in probabilistic risk assessments and individual plant evaluations (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 AFW system.

This study used as its source data the operating experience from 1987 through 1995 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 a U.S. commercial nuclear power plant experienced engineer from a risk and reliability perspective.

The AFW system unreliabilities 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 individual failure modes were calculated by reviewing the failure information, categorizing each event by failure mode, and then estimating the corresponding number of demands. Forty-seven plant risk reports (i.e., PRAs, IPEs, and NUREGs) were used for comparison to the AFW reliability results obtained in this study. These reports document AFW system information for 72 PWR plants.

The AFW system configurations for the 72 plants used in this study differ considerably. AFW systems comprise different levels of pump train redundancy and diversity. To facilitate the assessment of the AFW systems, 11 AFW design classes were identified, and the plants were categorized accordingly.

Major Findings

Based on the 1987–1995 experience data, there were no failures of the entire AFW system identified in 1,117 unplanned system demands. A simple Bayes estimate of the AFW system unreliability using this data is 4.5E-04 (probability of failure per demand) with an associated 90% uncertainty interval of [1.8E-06, 1.7E-03]. Using a system level fault tree model that combines individual failure modes, the operational unreliability of the AFW system calculated by arithmetically averaging the results of 72 plant-specific models is 3.4E-05. Individual plant results vary over two orders of magnitude, from 1.5E-06 to 6.2E-04. The variability largely reflects the diversity found in AFW system designs. However, there is some variation in results among plants with similar AFW designs. This is attributed to the plant-to-plant differences in the 1987–1995 experience data, and to a lesser degree, differences in the levels of redundancy in the feed control/injection headers. The estimates of AFW operational unreliability using fault tree analyses are plotted in Figure ES-1. Contributions to unreliability varied depending on the design and plant-specific data. Details for each class are provided in Section 3.2 of the report.

AFW designs composed of only turbine-driven pumps were the least reliable, while AFW designs comprising three redundant trains of diverse design (e.g., two motor and one turbine driven pumps) were more reliable. AFW designs consisting of four trains (three motor and one turbine) are not significantly different in reliability terms from the two motor and one turbine pump designs. The benefits of additional trains of redundancy to AFW system reliability is offset by the effects of common cause failures. Although the AFW designs consisting solely of turbine-driven pumps tend to be less reliable in routine operations, for potential station blackout situations, they would be more reliable than their counterparts with multiple motor-driven pump trains.

Generally, the turbine-driven pump trains are about a factor of 10 less reliable than motor-driven pumps trains and a factor of four less reliable than the diesel driven pump trains. There is no appreciable plant-to-plant variation

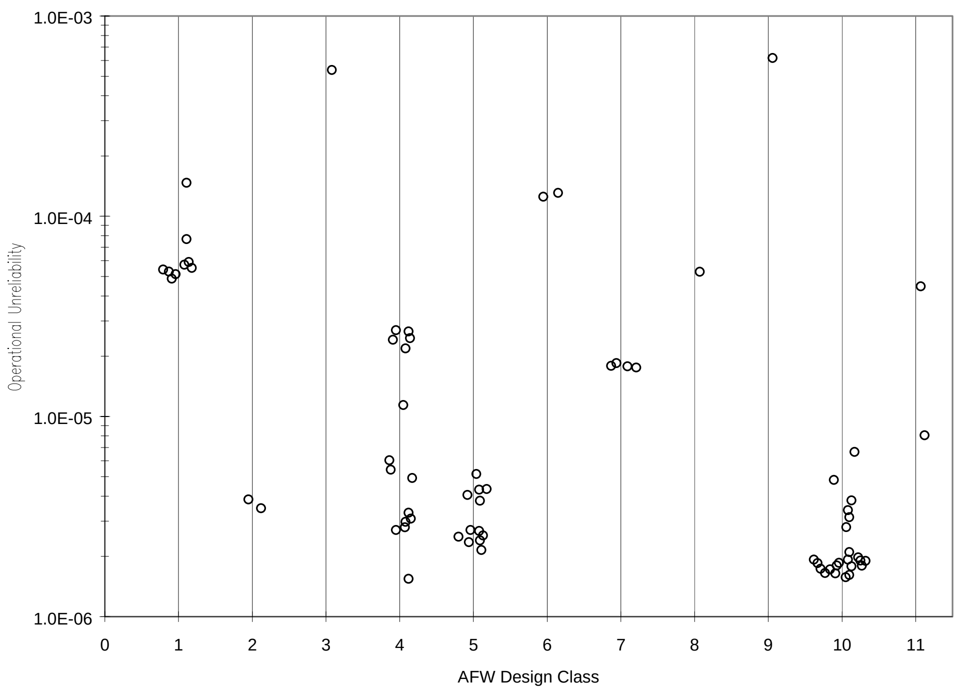

Figure ES-1. Plant-specific estimates of AFW system unreliability grouped by design class for an operational mission. Uncertainties are not plotted in order to provide better resolution of the plant-specific means. The uncertainties associated with the estimates are found in Table D-1 in Appendix D.

within the driver-specific pump train unreliabilities, which further supports the observation that AFW system unreliability (based on the 1987–1995 experience) is mostly influenced by the levels of redundancy and diversity in the specific system design. The plant-specific pump train unreliabilities are plotted in Figure ES-2.

The industry-wide arithmetic average of AFW system unreliability for a PRA mission (i.e. 24 hour run-time requirement) calculated using data extracted from PRA/IPEs is 3.4E-04. The corresponding estimate based on the 1987–1995 experience is 2.1E-03 or about a factor of six greater than the average of the PRA/IPE values. Neither of these estimates account for non-safety trains and equipment available at some plants (for example, the use of non-safety grade startup feedwater pumps). A plot of these estimates is shown in Figure ES-3. The major differences between the two estimates are attributable to the probabilities associated with failure of the primary AFW system water source (e.g., CST suction path, generally not considered as being probabilistically important in most PRA/IPEs), and the AFW turbine-driven pump failure to run (a significantly higher failure rates results when using the relatively limited 1987–1995 experience data).

However, the loss of suction source was a dominant contributor to many of the design classes. This event, though rare, is important because it disables the designed redundancy of the AFW systems and is usually discounted or not modeled in PRAs. There was one failure of a suction source during the 1,117 unplanned system demands observed in the operational experience. This failure occurred during an automatic start of two motor-driven pumps in which, suction

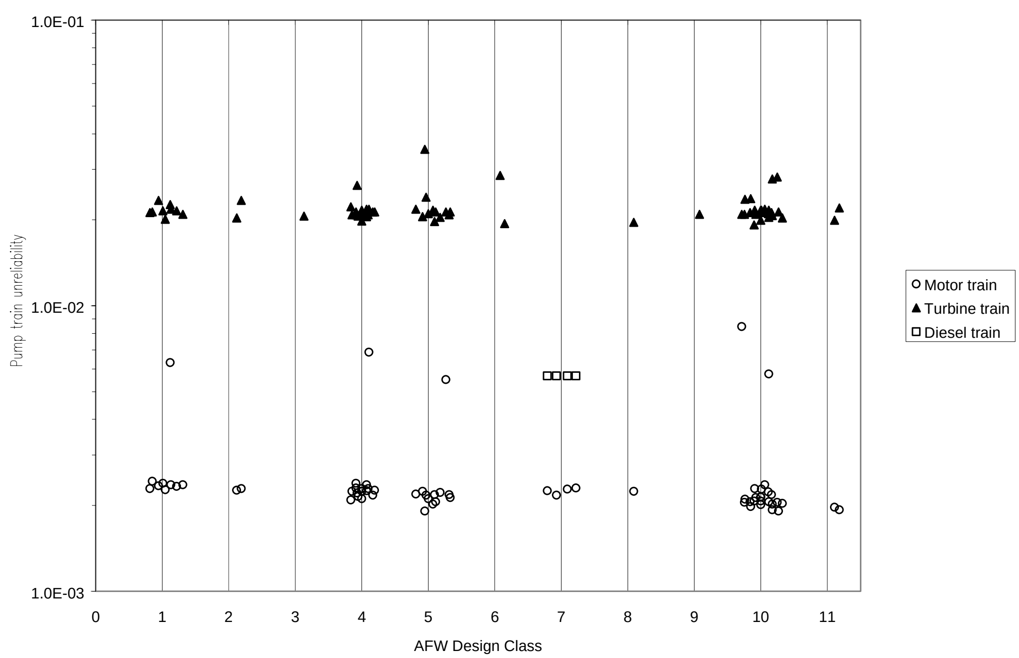

Figure ES-2. Plant-specific estimates of AFW system pump train operational unreliability grouped by design class.

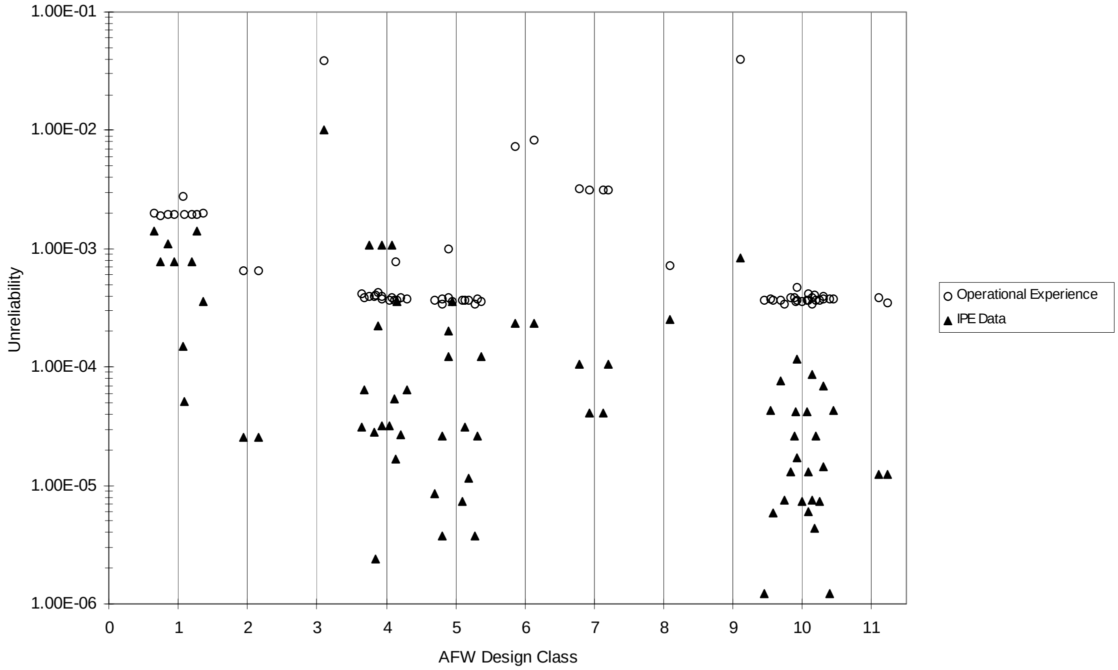

Figure ES-3. Plot of the PRA/IPE and operating experience estimates of AFW unreliability for a PRA mission. Uncertainties are not plotted in order to provide better resolution of the plant-specific means. The uncertainties associated with the estimates are found in Tables D-2 and D-3 in Appendix D.

pressure was insufficient for pump operation which caused an automatic shift to the assured source (service water). The low suction pressure condition was a result of operating with the AFW condensate storage tank isolated, while not maintaining adequate level in the upper surge tank, which provides an alternate source of feedwater to AFW. Even though AFW pump suction shifted to the assured source (service water), the service water system was fouled with clams and sludge which caused the AFW flow control valves to the steam generators to clog with clams and sludge significantly reducing flow to two of four steam generators.

No trends were identified in the AFW operational mission unreliability when plotted against calendar year (Figure ES-4) or low-power license date (Figure ES-5). Although a decreasing trend is visible when unreliability is plotted against calendar year or low-power license date, the trends are not statistically significant. Trends were identified in the frequency of the AFW unplanned demands. When plotted against calendar year, the unplanned demand frequency exhibited a statistically significant decreasing trend (Figure ES-6). When unplanned demand frequency is plotted against low-power license dates, a statistically significant increasing trend was identified (Figure ES-7).

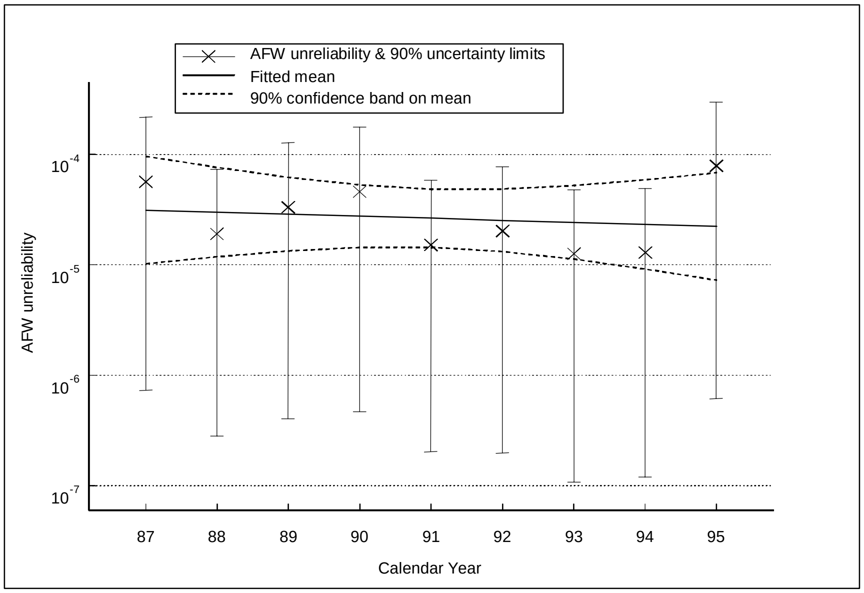

Figure ES-4. AFW system unreliability plotted by calendar year. The plotted trend is not statistically significant (P-value = 0.66).

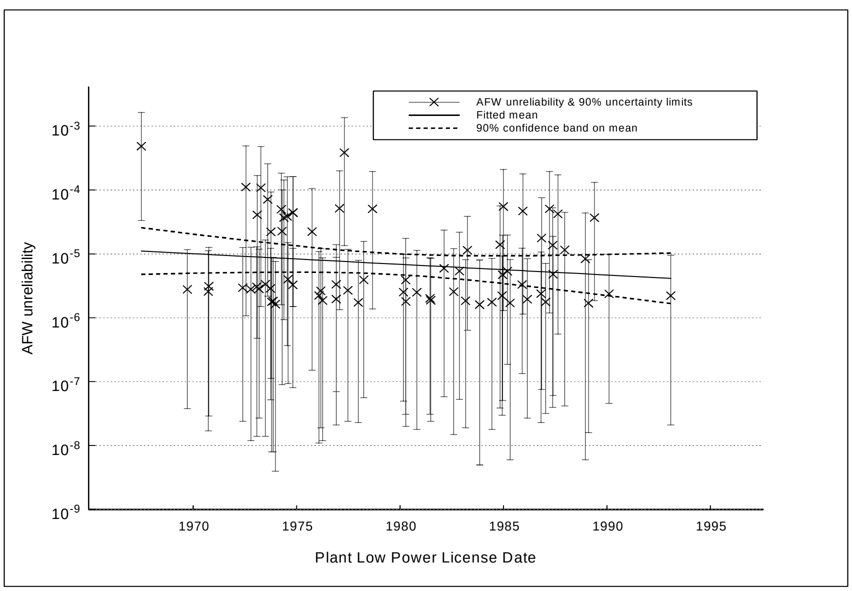

Figure ES-5. Plant-specific AFW system unreliability plotted by low-power license dates. The plotted trend is not statistically significant (P-value = 0.18).

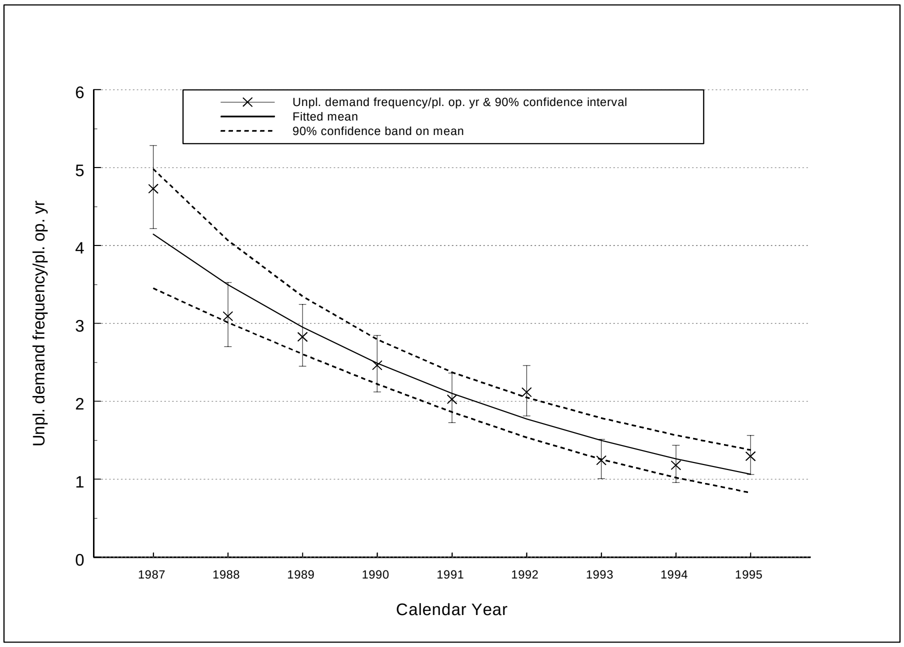

Figure ES-6. Unplanned demands trended by calendar year, with confidence limits on the individual frequencies. The decreasing trend is highly statistically significant (P-value <5E-5).

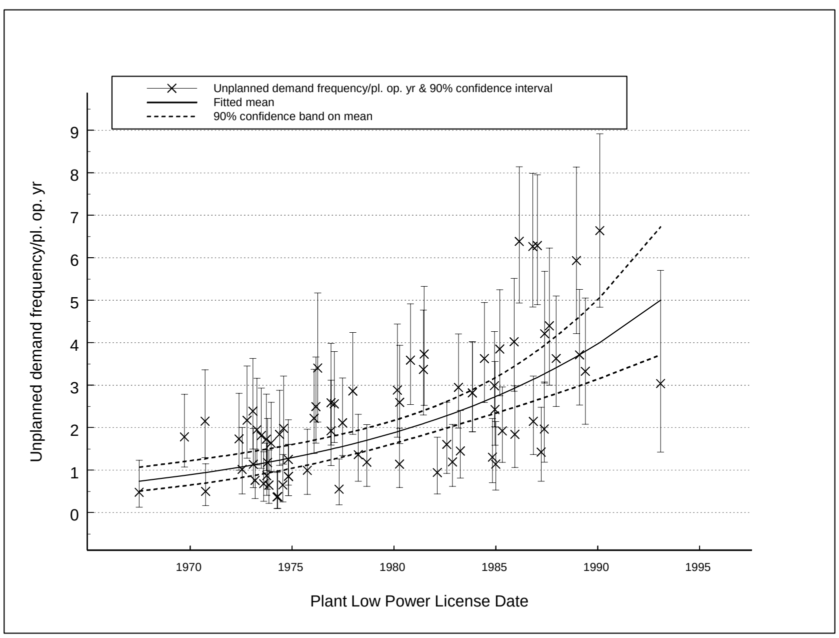

Figure ES-7. Unplanned demand frequency versus low-power license date, with confidence limits on the frequencies. The increasing trend is highly statistically significant (P-value <5E-5).

Estimates of AFW unreliability have been used in past regulatory analyses and rulemaking addressing the design and operation of the AFW system, in particular, the Standard Review Plan (NUREG-0800), Station Blackout (NUREG-1032), and ATWS (SECY-83-293). The estimates provided in these documents were compared with the estimates presented in this report, based on the 1987–1995 operating experience. These comparisons demonstrated that the operating-experience-based estimates are similar to or slightly better than those used in the regulatory applications.

FOREWORD

This report provides information relevant to auxiliary/emergency feedwater (AFW) system performance in response to both normal operational transients and the more demanding probabilistic risk assessment (PRA) mission (long-term operation) 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 Analysis and Evaluation of Operational Data 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 AFW systems at 72 United States commercial pressurized water reactors based on 1987–1995 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 AFW systems, and how both industry (generic) and plant-specific performance compares with reliability estimates from 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 AFW 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, turbine-driven pump starting reliability, 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 for Analysis and Evaluation of Operational Data plans to periodically update the information in this report as additional data becomes available.

Charles E. Rossi, Director
Safety Programs Division
Office for Analysis and Evaluation
of Operational Data

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

Failure information from the 1987-1995 operating experience used to estimate system unreliability (event summaries, failure modes, and LER references)	Table C-1[a]
Dominant contributors to AFW system unreliability for an operational mission	Sections 3.2.2–3.2.5
Dominant contributor (or failure mode) rankings by importance factor and AFW design class	Table D-10
Causal factors affecting dominant contributors to AFW 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 AFW operational unreliability	Table D-5
System failure mode data and probability information	Table 4
Common cause failure parameters used for calculating system unreliability	Table 3
Plant-specific basic event failure probabilities and rates (where such variation could be modeled)	Tables E-3–E-12
Plant-specific estimates of AFW unreliability for a PRA-based mission (long-term operation) based on the operating experience and IPE failure rates	Tables D-6, D-7

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.

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Technical contributions were made by S. T. Beck, S. D. Novack, and F. M. Marshall of the INEEL.

ACRONYMS

AEOD	Analysis and Evaluation of Operational Data (NRC Office)
AFW	auxiliary feedwater
AOV	Air-operated valve
ASEP	Accident Sequence Evaluation Program
ASP	accident sequence precursor
ATWS	anticipated transients without scram
CCDP	conditional core damage probability
CCF	common cause failure
CFR	Code of Federal Regulations
CST	condensate storage tank
D	diesel
DDP	diesel-driven pump
DIS-SEG	discharge segment for CCF designator
EOC	error of commission
ESF	engineered safety feature
FTR	failure to run
FTS	failure to start
FTO	failure to operate
HVAC	heating, ventilating, and air conditioning
IEEE	Institute of Electrical and Electronic Engineers
INEEL	Idaho National Environmental and Engineering Laboratory
INJ	injection segment
IPE	individual plant examination
LER	Licensee Event Report

LOFW	loss-of-feedwater accident
M	motor
MDFP	motor-driven feedwater pump
MDP	motor-driven pump
MFW	main feedwater
MOOS	maintenance-out-of-service
MOV	motor-operated valve
MSIV	main steam isolation valve
NPRDS	Nuclear Plant Reliability Data System
NRC	U.S. Nuclear Regulatory Commission
NSSS	nuclear steam supply system
ORNL	Oak Ridge National Laboratory
PMPS	pumps (excluding driver)
PRA	probabilistic risk assessment
PWR	pressurized water reactor
Q_t	total failure frequency of both the independent and dependent failures
RCIC	reactor core isolation cooling
RHR	residual heat removal
SAS	SAS Institute, Inc.'s commercial software package
SCSS	Sequence Coding and Search System (database maintained at ORNL)
SG	steam generator
SRV	safety relief valve
ST (or STM)	steam supply
SUC	suction segment
T	turbine

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 feed control segment—The portion of the AFW system that applies to plants where the turbine/diesel and electric-motor-driven pumps discharge to a shared header with flow to the steam generator 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 steam generator. Included with the segment are the associated valves and valve operators, the flow control 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 not 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 either actual low steam generator water level conditions, safety injection demands, or losses of normal feedwater.

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

Diesel-driven pump segment—The portion of the AFW system that includes the diesel engine, the associated fuel oil including the day tank, cooling water up to the supply isolation and the governor, and the engine starting system. Also included with this segment are the pump and associated piping from and including the suction isolation 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.

Diesel-driven pump feed control segment—The portion of the AFW system that includes the piping and valves from the pump discharge isolation up to but not including the check valve just prior to entering the steam generator. Included with the segment are the associated valves and valve operators, the flow control valve and the control logic, and the test recirculation line if applicable

Electric-motor driven pump segment —The portion of the AFW 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.

Electric-motor driven pump feed control segment—The portion of the AFW system that includes the piping and valves from the pump discharge isolation up to but not including the check valve just prior to entering the steam generator. Included with the segment are the associated valves and valve operators, the flow control valve and the control logic, and the test recirculation line if applicable

Error of commission (EOC)—A failure of the AFW system as a result of being rendered inoperable by operator action when the system was needed to restore steam generator level.

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

Failure—An inoperability in which the capability of the AFW system or train to supply water to a SG was lost when a demand for AFW existed. For estimating the operational unreliability, a subset of the failures was used (that is, only those that occurred on unplanned 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 a steam generator (SG), tripped off for a valid reason, and then could not be restarted.

Failure to operate (FTO)—Failure to operates occurs if, during an unplanned demand, the AFW train segment, other than pump train segment, prevents the AFW system from delivering water to the affected SG. FTO-SG pertains to the SG check valve segment immediately upstream of the SG. FTO-INJ refers to the piping/valve segment that controls/regulates flow of water to the SG. FTO-ST refers to the steam supply isolation valves to the turbine-driven pump.

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

Fault—An inoperability in which the ability of the AFW system to supply water to an SG was not lost. This includes administrative technical specifications violations such as late performance of a surveillance test.

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 AFW 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 of a segment of the AFW system because of maintenance activities, the segment is prevented from starting automatically during an unplanned demand.

Maintenance unavailability—Probability that the system is out of service for maintenance at any moment 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 AFW to be available throughout the entire mission time.

Operating conditions—Conditions in which technical specifications require AFW 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 (0.05 for this study) at which the assumed model or hypothesis is statistically rejected.

Recovery—An act that enables the AFW system to be recovered from a failure without maintenance intervention. Generally, recovery of the AFW 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 AFW 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.

Steam generator feed segment—The portion of the system that includes the check valve(s) and associated piping upstream of the common or turbine/motor feed segments. The last set of check valves in the feedwater system piping that prevents short cycling of AFW flow to the main feedwater system was included in this segment.

Suction segment—The portion of the AFW system that includes all piping and valves (including valve operators) from the feedwater source, but not including the feedwater source, to the pump suction isolation valves.

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

Turbine-driven pump segment—The portion of the AFW system that includes the turbine, trip, and throttle valve, governor assembly with the associated controls, the turbine steam supply isolation just upstream of the trip throttle valve, and the valve operators. Also included with this segment is the pump and associated piping from and including the suction isolation 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.

Turbine steam supply segment—The portion of the AFW system that includes the associated piping, valves, and valve operators from the main steam line penetrations to the turbine steam supply isolation valve. The instrument air supply and dc power to the solenoid operated valves was excluded.

Turbine-driven pump feed control segment—The portion of the AFW system that includes the piping and valves from the pump discharge isolation up to but not including check valve just prior to entering the steam generator. Included with the segment are the associated valves and valve operators, the flow control valve and the control logic, and the test recirculation line if applicable.

Unreliability—Probability that the AFW 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.

Auxiliary/Emergency Feedwater System Reliability, 1987–1995

1. INTRODUCTION

The U.S. Nuclear Regulatory Commission (NRC), Office for Analysis and Evaluation of Operational Data (AEOD) has, in cooperation with other NRC offices, undertaken an effort to ensure that the stated NRC policy to expand the use of probabilistic risk assessment (PRA) within the agency is implemented in a consistent and predictable manner. As part of this effort, the AEOD Safety Programs Division has undertaken 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 auxiliary/emergency feedwater systems in the U.S. commercial pressurized water reactors (PWRs) was performed. Because of the different terminology used throughout the industry for simplicity the auxiliary/emergency feedwater systems will be referred to in this report as the auxiliary feedwater (AFW) system.

The evaluation measures AFW system unreliability using actual operating experience. To perform this evaluation and make risk-based comparisons to the relevant information provided in the PRAs, unreliability estimates are presented in this study for two conditions. First, estimates of the reliability of the system in performing its mission resulting from actual plant transients are presented. These transients include actual low water level conditions in one or more steam generators or safety injection demands. Second, the operational experience data are used to predict the reliability of the AFW system in performing the risk-significant function postulated in probabilistic risk assessments and individual plant examinations (PRA/IPEs). The estimates of AFW system unreliability are based on data from unplanned demands in response to a plant transient condition. The data from this source are considered to best represent 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. Data from surveillance test failures were not used in this study because failures of an individual train of AFW during a surveillance test are not reportable in accordance with 10 CFR 50.73, the Licensee Event Report (LER) reporting rule. 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 AFW system operational data.

This report is arranged as follows. Section 1 provides the introduction. Section 2 describes the scope of the study, describes the AFW system and system boundaries, provides the description of the eleven AFW 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 AFW unreliability, modeling of common cause failures, and the fault tree models associated with the eleven AFW design classes. Also contained in Section 3 are estimates of operational unreliability of the AFW system and pump train and feed control segments, design class differences, comparisons to PRA/IPEs and regulatory issues (i.e., Station Blackout, ATWS, and Standard

Review Plan), as well as AFW system unreliability trends by calendar year and low-power license date (i.e., new plants versus older plants). Section 4 provides results on the trends of failures and unplanned demands and scram frequency by calendar year and low-power license date. Also included in Section 4 are engineering insights into the factors affecting the system, pump segment, and feed segment reliability as well as an evaluation of the failures that contributed to the various 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. Appendix E summarizes the detailed statistical analyses used to determine the results presented in Sections 3 and 4 of the body of this report.

2. SCOPE OF STUDY

This study documents an analysis of the operational experience of 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. However, a pump identified in an IPE as part of the AFW system but does not automatically start or is not classified as safety-related was excluded from the reliability analysis provided in this report. Since LERs are not required to be submitted for these types of pump trains, estimates for these types of non-safety components were not calculated. 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, the number of steam generators, the report used to obtain the estimates of plant-specific system unreliability, and other risk-related information. Details of the calculation of operational time are provided in Appendix A, and plant data results are provided in Appendix C.

2.1 System Operation and Description

2.1.1 System Purpose

The main purpose of the AFW system is to provide feedwater to the steam generators to maintain a heat sink in the event of (1) a loss of main feedwater, (2) a reactor trip and loss of offsite power, and (3) a small break loss of coolant accident. The system, at some plants, can also provide a source of feedwater to the steam generators during plant startup and shutdown. However, the system cannot supply sufficient feedwater flow during power operation. At most plants, the system can only supply adequate feedwater to the steam generators with steam loads less than 5% of rated flow.

The safety-related function of the AFW system is to maintain water inventory in the steam generators for reactor residual heat removal when the main feedwater system is unavailable. The system is designed to automatically start and supply sufficient feedwater to prevent the relief of primary coolant through the pressurizer safety valves. The AFW system, in conjunction with the steam generators and the main steam line atmospheric reliefs and/or safety valves, is used to cool the reactor coolant system to the residual heat removal cut-in temperature. At this temperature, the residual heat removal system is used to further cool the reactor coolant system. The AFW system may also be used to temporarily hold the plant in a hot standby condition while main feedwater flow is being restored, with the option of cooling the reactor coolant system to the residual heat removal system initiation temperature.

2.1.2 System Description

The AFW systems analyzed can be grouped into 11 different design classes as shown in Table 1. Figure 1 provides a block diagram of each of the design classes. Each system typically consists of at least two independent divisions. The divisions consist of a number of different combinations of electric-motor-driven and/or turbine-driven pump trains. Electrical power, control, and instrumentation associated with each division are independent from one another. Typically, the electric-motor-driven pump trains make up one division and the turbine-driven pump train the other. Some plants have a diesel-driven pump in place of the turbine-driven pump, or a second turbine-driven pump in place of the electric-motor-driven pumps. Because of the diversity in system design, operation, and response to a plant transient, a detailed discussion of the different systems for each plant is not practical. A general description is provided of a

Table 1. Listing of the AFW design classes, PWRs associated with each design class, the number and type of AFW trains, the number of steam generators, and the success criterion (as stated in the IPEs).

AFW Design Class	Plant Name	Report References	Motor Trains	Turbine Trains	Diesel Trains	Total Pump Trains	Steam Generators	Success Criterion Reported in the IPE	Mission Time (hours)
1	Arkansas Nuclear One 1 & 2	1, 2	1	1		2	2	1 of 2 trains to 1 of 2 SGs	24
1	Crystal River 3	3	1	1		2	2	1 of 2 trains to 1 of 2 SGs	24
1	Fort Calhoun	4	1	1	1*	3	2	1 of 2 trains or FW-54 (diesel-driven) to 1 of 2 SGs; since diesel is non-safety and manual start—model as 1 of 2 trains with diesel as recovery train	24
1	Palo Verde 1, 2, & 3	5	2*	1		3	2	1 of 3 pumps to one (1 of 2) SGs; one motor train (MD-N) is nonessential; so net is 1 of 2 trains	24
1	Prairie Island 1 & 2	6	1	1		2	2	1 of 2 trains to 1 of 2 SGs	24
2	Calvert Cliffs 1 & 2	7	1	2		3	2	300 gpm to 1 (or 2) SGs -- IPE models pumps as 1 of 4 (3 plus xtie) available	24
3	Davis-Besse	8	1*	2		3	2	1 of 3 trains to at least 1 SG (1 of 2 SGs); the MDFP serves as the MDP train and as BU to turbines, needs to be manually started; treat the MD train as recovery if the auto turbines fail. Success is 1 of 2 safety trains to 1 of 2 SGs	24
4	Point Beach 1 & 2	9	2	1		3	2	The units have only one MDP but supplies a SG at each unit net effect is 2 MD trains; 1 of 3 trains to 1 of 2 SGs	24
4	Ginna	10	2	1		3	2	1 of 3 pumps to 1 of 2 SGs	24
4	Kewaunee	11	2	1		3	2	200 gpm to 1 of 2 SGs from 1 of 3 AFW pumps	24
4	Millstone 2	12	2	1		3	2	1 of 2 MDP or the steam-driven pump delivers flow to 1 of 2 SGs	24
4	Oconee 1, 2, & 3	13	2	1		3	2	1 of 3 trains to 1 of 2 SGs	24
4	Palisades	14	2	1		3	2	1 of 3 pumps to 1 of 2 SGs	24
4	San Onofre 2 & 3	15	2	1		3	2	1 of 3 AFW pumps to 1 of 2 SGs	24
4	St. Lucie 1 & 2	16	2	1		3	2	1 of 3 AFW pumps to 1 of 2 SGs	24
4	Three Mile Island 1	17, 18	2	1		3	2	1 of 3 pumps to 1 of 2 SGs	24
4	Waterford 3	19	2	1		3	2	Any pump (1 of 3 AFW) to 1 of 2 SGs	24
5	Beaver Valley 1 & 2	20, 21	2	1		3	3	1 of 3 trains to 1 of 3 SGs	24
5	Farley 1 & 2	22	2	1		3	3	1 of 3 trains to 2 of 3 SGs	4

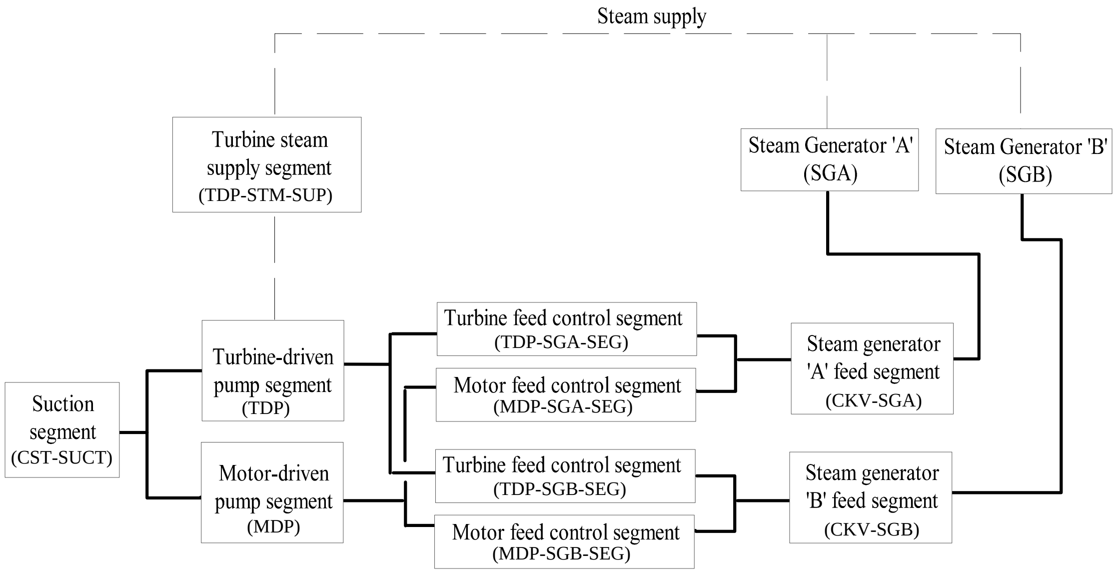
Table 1. (continued).

AFW Design Class	Plant Name	Report References	Motor Trains	Turbine Trains	Diesel Trains	Total Pump Trains	Steam Generators	Success Criterion Reported in the IPE	Mission Time (hours)
5	Harris 1	23	2	1		3	3	1 of 3 trains to 1 of 3 SGs	24
5	Maine Yankee	24	2	1		3	3	1 of 3 trains to 1 of 3 SGs (2 of 2 pumps with flow diversion)	24
5	North Anna 1 & 2	25	2	1		3	3	1 of 3 trains to 1 of 3 SGs	24
5	Robinson	26	2	1		3	3	1 of 3 pumps to 1 of 3 SGs	24
5	Summer 1	27	2	1		3	3	1 of 2 MDPs OR 1 TDP to 1 of 3 SGs	24
5	Surry 1 & 2	28	2	1		3	3	1 of 3 pumps to any one SG	24
6	Turkey Point 3 & 4	29		3		3	3	1 of 3 pumps to at least 1 of 3 SGs (375 gpm)	15 hours in Mode 3 followed by 4 hours of cooldown OR 23 hours hot standby
7	Braidwood 1 & 2	30	1		1	2	4	1 of 2 trains to 1 of 4 SGs	24
7	Byron 1 & 2	31	1		1	2	4	1 of 2 trains to 1 of 4 SGs	24
8	Seabrook	32	1	1		2	4	PRA states 1 of 2 pumps to 2 of 4 SGs	9
9	Haddam Neck	33		2		2	4	(1 of 2 AFW pumps to 3 of 4 SGs) OR (2 of 2 pumps to 2 of 4 SGs)	24
10	Callaway	34	2	1		3	4	1 of 3 trains delivering flow to at least 2 SGs	24
10	Catawba 1 & 2	35	2	1		3	4	1 of 3 trains to 2 SGs	24
10	Comanche Peak 1 & 2	36	2	1		3	4	At least 300 gpm (1 of 3 trains) to 1 of 4 SGs; also have a 860 gpm (2 of MDP to 1 of 4 SGs or 1 TDP flow to 2 SGs); full flow--3 of 3 pumps with MDPs to 1 SG and TDP to 2 SGs	24
10	Cook 1 & 2	37	2	1		3	4	450 gpm AFW flow (1 of 3 trains) to 2 of 4 SGs	24
10	Diablo Canyon 1 & 2	38	2	1		3	4	1 of 3 trains to 1 of 4 SGs	24
10	Indian Point 2	39	2	1		3	4	1 of 3 AFW pumps to 1 SG	24
10	Indian Point 3	40	2	1		3	4	1 of 3 trains injecting to 1 of 4 SGs	24
10	McGuire 1 & 2	41	2	1		3	4	1 of 3 trains to 2 of 4 SGs	24
10	Millstone 3	42	2	1		3	4	1 of 3 pumps to any 2 of 4 SGs	24
10	Salem 1 & 2	43	2	1		3	4	426 gpm flow (1 of 3 pumps) to 2 SGs (MDP 440 gpm; TDP 880 gpm)	24

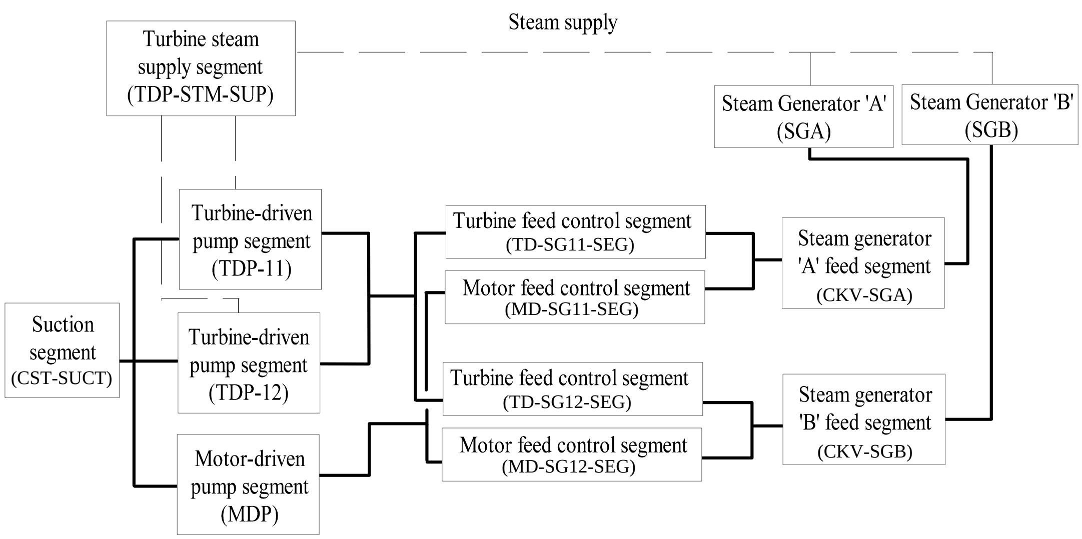
Table 1. (continued).

AFW Design Class	Plant Name	Report References	Motor Trains	Turbine Trains	Diesel Trains	Total Pump Trains	Steam Generators	Success Criterion Reported in the IPE	Mission Time (hours)
10	Sequoyah 1 & 2	44	2	1		3	4	at least one pump (1 of 3) feeding 2 SGs	24
10	Vogtle 1 & 2	45	2	1		3	4	Flow to 2 of 4 SGs from 1 of 2 MDPs or 1 TDP	5
10	Wolf Creek	46	2	1		3	4	1 of 3 trains to 2 of 4 SGs	24
10	Zion 1 & 2	47	2	1		3	4	1 of 3 pumps to 4 of 4 SGs or 1 of 4 SGs w/o all power. Page 4-48 states 1 MDP supplying 2/4 SGs is enough to safely cool down plant to RHR temp.	24
11	South Texas 1 & 2	48	3	1		4	4	1 of 4 AFW trains to 1 of 4 SGs (pump flow to its respective SG) no xtie to other SGs modeled in PRA	24

Note: * denotes plants that used a non-safety pump trains as part of the IPE success criteria.

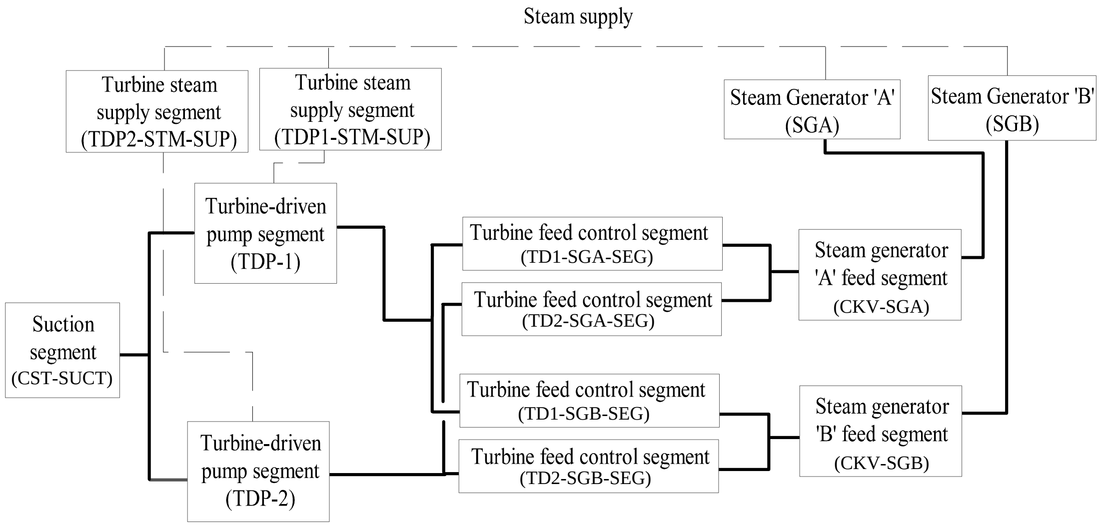


Crystal River 3 (Design Class 1)

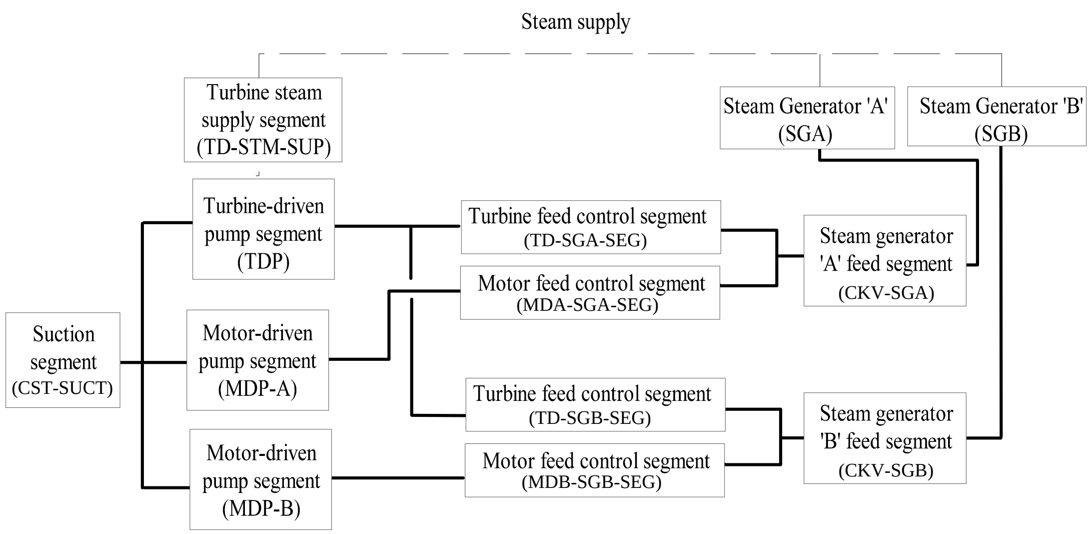


Calvert Cliffs 1 (Design Class 2)

Figure 1. Simplified block diagrams of AFW systems for each of the 11 design classes.

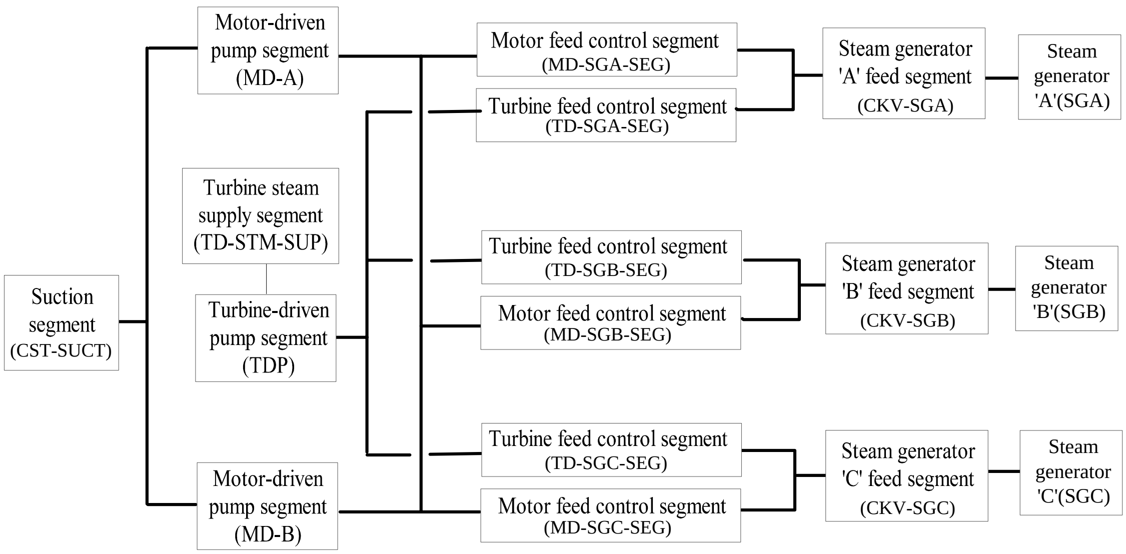


Davis-Besse (Design Class 3)

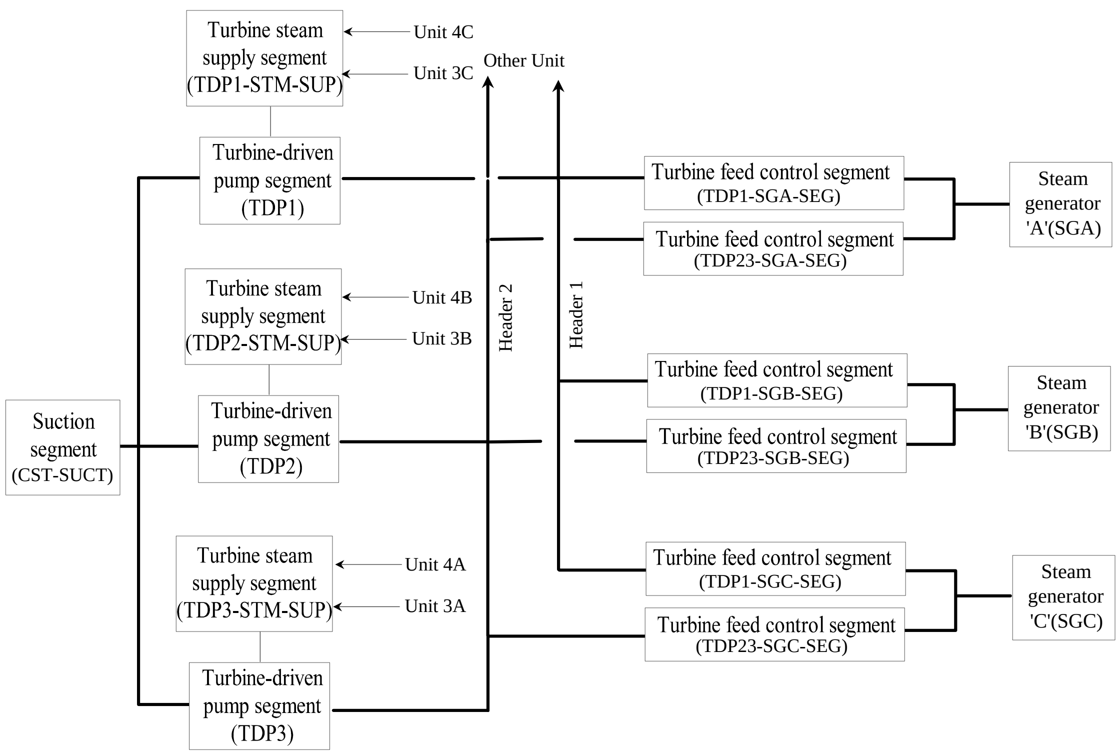


St. Lucie 1 (Design Class 4)

Figure 1. (continued).

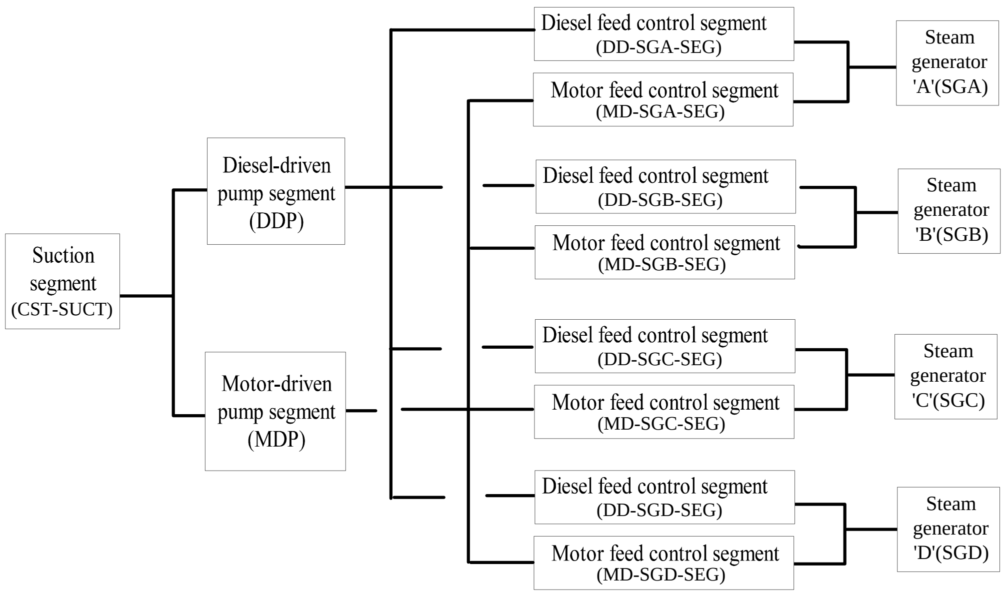


Farley 1 (Design Class 5)

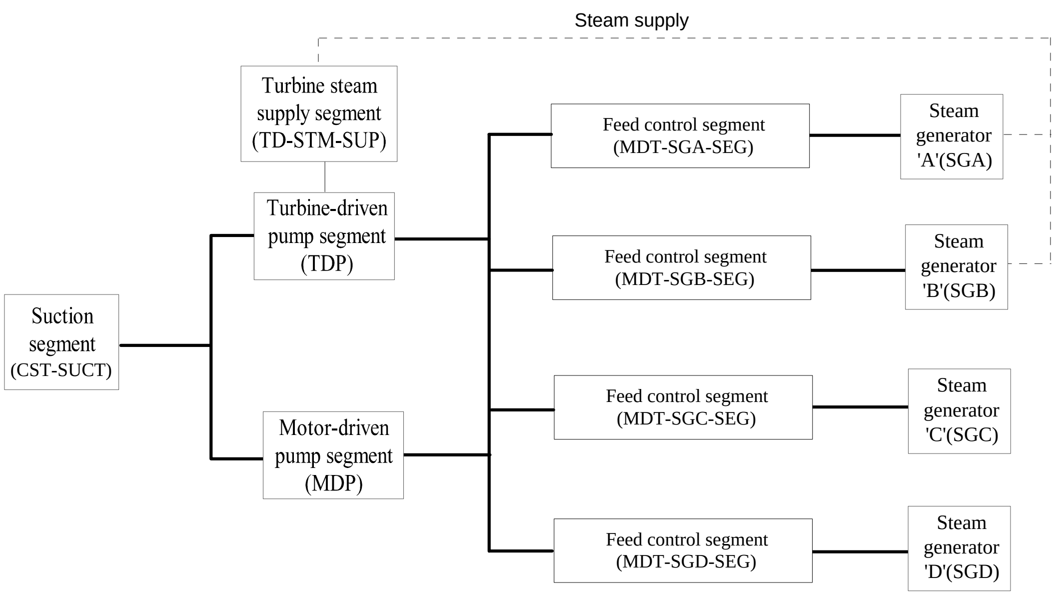


Turkey Point 3 (Design Class 6)

Figure 1. (continued).

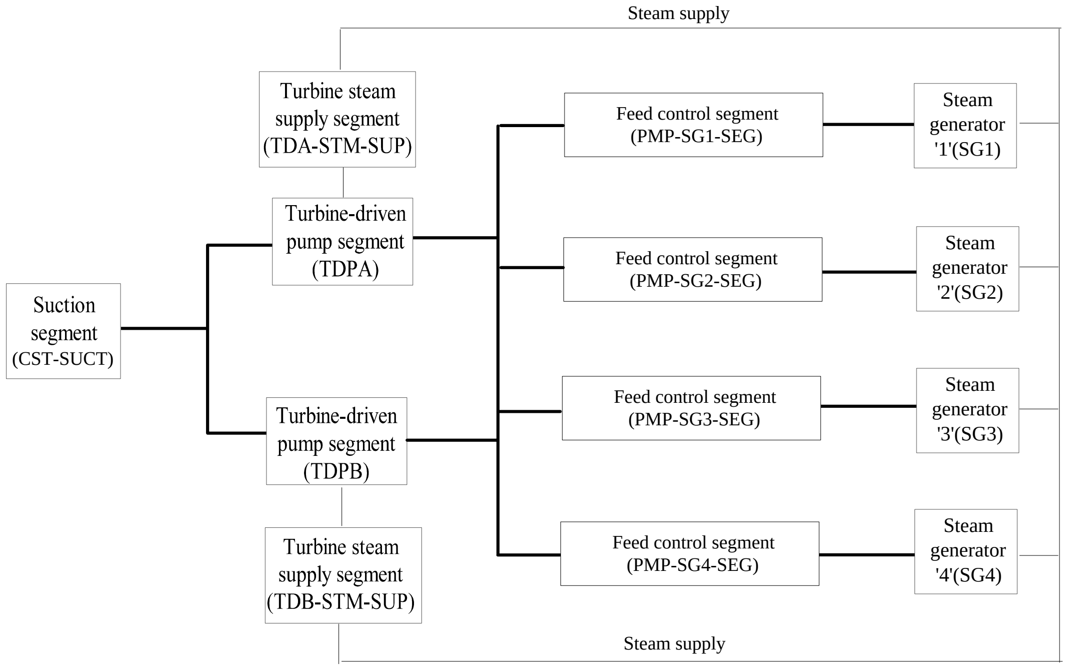


Braidwood (Design Class 7)

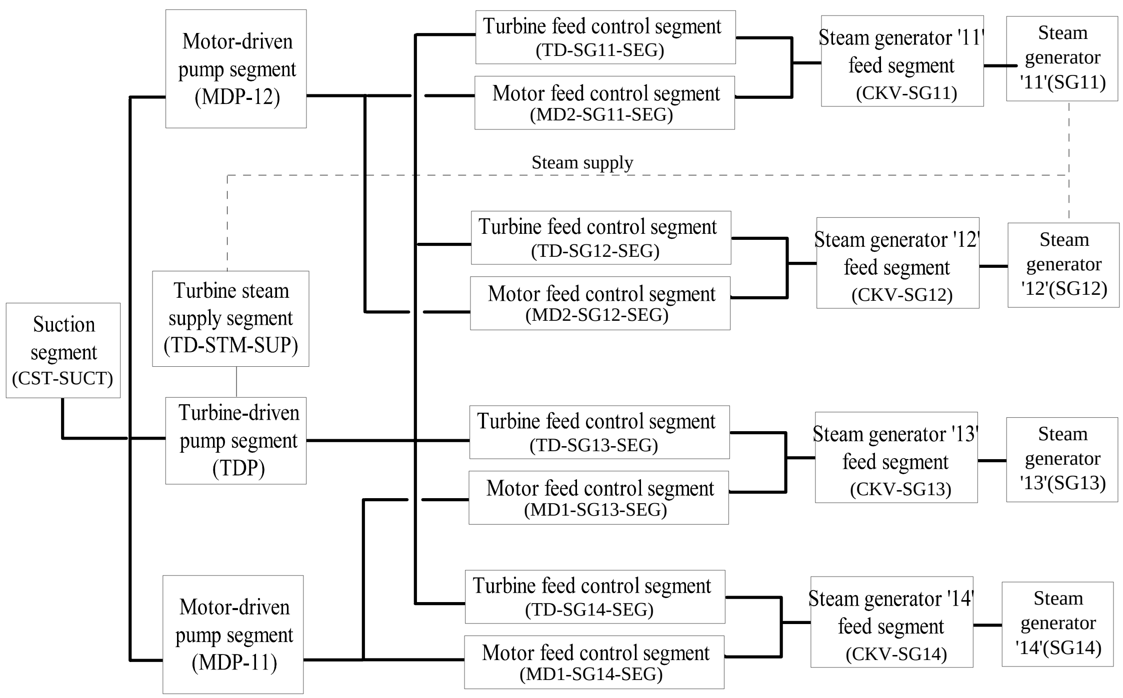


Seabrook (Design Class 8)

Figure 1. (continued).

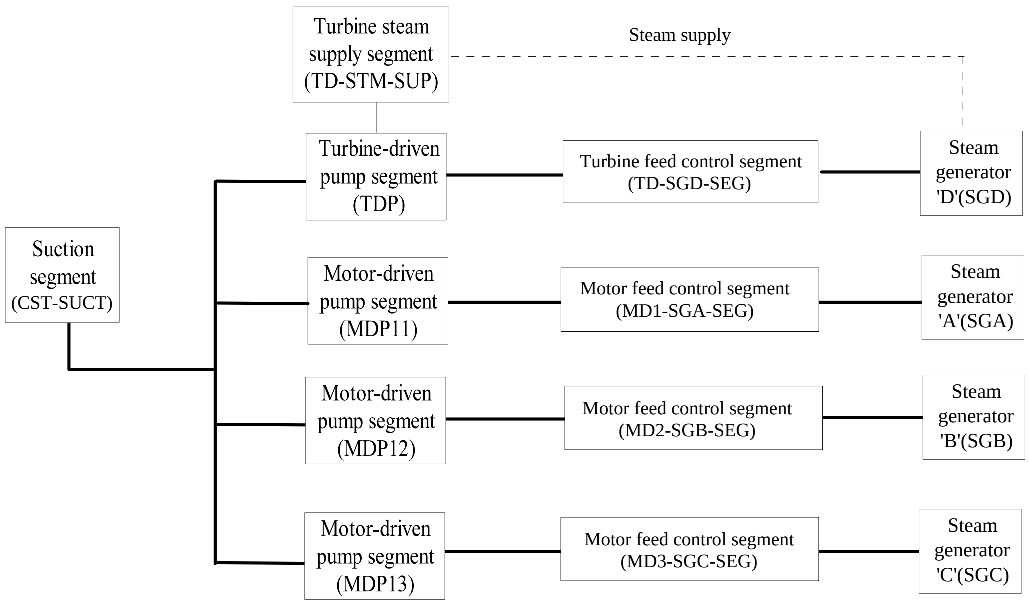


Haddam Neck (Design Class 9)



Salem 1 (Design Class 10)

Figure 1. (continued).



South Texas 1 (Design Class 11)

Figure 1. (continued).

two-division system for a four steam generator plant consisting of two electric-motor-driven pumps in one division and a turbine-driven pump in the other. Differences between the other types of system design classes are also discussed.

The reader is cautioned against making comparisons or assumptions across the industry or between plants (including dual unit sites) concerning the operation and design features of the AFW system. Even if the system configuration is the same between similar plants, the system may have different initiation parameters, and the response during a steam generator level transient may also be different. For example, given a low water level condition in a steam generator at some plants, all pumps start, while at others, only the electric-motor-driven pumps start. In addition, once the pumps start, at some plants, the system may not provide flow to the steam generators until level reaches a second lower level setpoint or until a time delay relay times out. Along with these differences, control of feedwater flow also differs considerably. Some plants have automatic flow control, while others control flow manually upon system initiation. In addition, some flow control valves are normally open and modulate closed to control flow, while others are normally closed and must open to provide flow.

The AFW system is typically started automatically by the engineered safety features actuation system (ESFAS) or equivalent, depending on plant design and terminology. The ESFAS system automatic start signals include a predetermined low water level condition in one or more steam generators, a loss of the operating main feedwater pumps, a loss of electrical power on safety-related buses, and a safety injection signal. There are additional start signals, but these four are the most common. There is significant variation among the plants in how the system responds given a start signal. However, in most cases, a low-level condition in one steam generator starts only the electric-motor-driven pumps, while a low-level condition in two or more steam generators starts both the electric and turbine-driven pumps. For the plants that have two divisions consisting of one train per division (i.e., an electric-motor and turbine-driven pump train), most start signals start both pumps.

A typical AFW system is configured with two separate mechanical divisions. Each division has independent initiation and control functions, and is designed to feed all the steam generators at full capacity. One division may consist of two electric-motor-driven pumps, while the other division may have only one turbine-driven pump. Typically, in a four steam generator plant, each electric-motor-driven pump train has the capacity to supply two steam generators, while the turbine-driven pump train can supply all four steam generators. In the two-division two-train plants, both pumps are aligned and rated to supply all the steam generators.

Feedwater flow to each steam generator is normally controlled by a flow control valve that will modulate either open or closed to maintain steam generator level. The flow control valve can be controlled either automatically or manually. A flow recirculation line is provided downstream of each pump discharge. The recirculation line allows for continuous flow back to the suction source to provide minimum flow protection for the pump. In addition, a test return line is provided downstream of each pump discharge to allow for either full or partial testing of the pumps. To limit the flow, as steam generator pressure lowers during a cool down, the system utilizes several different methods depending on plant design. Some plants use a current limiter that acts to increase downstream pump pressure thereby reducing motor amps, others use flow restricting orifices or pipe design configurations, and others use the flow control valve that modulates closed when a flow reduction signal is received.

The turbine for each turbine-driven pump is classified as an atmospheric discharge, non-condensing turbine. Typically, driving steam is supplied from the main steam lines upstream of the main steam isolation valves from at least two steam generators. (Design class 11 turbine steam supply is from one steam generator.) Each steam supply line to the turbine contains a normally closed fail-open air operated steam isolation valve. Some plants have a dc-powered motor-operated valve. A bypass is provided around each of these isolation valves with a flow-restricting orifice and a normally closed fail-open air-operated bypass isolation valve. The bypass provides a small, controlled rate of steam flow to the AFW turbine for warming the steam lines and turbine. Steam drain traps are provided in the low points of the steam line to drain condensate from the lines as condensate present in the steam lines could have an adverse affect on turbine reliability during an unplanned demand.

Each turbine is supplied with a hydraulic governor control valve, and a trip and throttle valve with motor reset capability. The turbine is brought up to speed by governor control upon being supplied with steam by opening the steam supply isolation valve(s). The governor then controls the turbine speed at the pump rated speed by modulating the governor control valve. The governor controlled turbine speed can be adjusted from the control room, the remote shutdown panel, or manually at the governor.

The turbine is stopped by remotely closing the trip throttle valve from the control room or the remote shutdown panel. The trip and throttle valve is automatically (electrically) tripped on turbine overspeed at 115% of rated speed. The electric overspeed trip can be reset from either the control room or remote shutdown panel. A mechanical overspeed trip also provides automatic overspeed protection at 125% of rated speed. The mechanical overspeed trip can only be reset at the trip and throttle valve.

Feedwater is supplied to both divisions through either a single condensate storage tank with separate suction supply lines or two storage tanks with redundant supply lines. Each tank typically will have its level maintained above the minimum volume needed to provide a net positive suction head to the pumps and allow for 6 hours of system operation. For extended operation of the system or as a backup for the storage tanks, an ensured source of water is provided from a service water system. The switchover to the ensured source can be accomplished by either an automatic re-alignment of the suction valves based on a sensed, low-suction pressure condition or manually by operator action depending on the plant design (typical alignment at most plants is by manual capability).

2.1.3 System Boundaries

For the purposes of this analysis, the AFW system was partitioned into several different segments. These segments are (1) suction, (2) turbine-driven pump, (3) turbine steam supply, (4) turbine-driven pump feed control, (5) electric-motor-driven pump, (6) electric-motor-driven pump feed control, (7) diesel-driven pump, (8) diesel-driven pump feed control, (9) common feed control, and (10) steam generator feed. These segments are described in more detail below:

1. The suction segment includes all piping and valves (including valve operators) from the condensate storage tank (or equivalent based on plant terminology) to the pump suction isolation.

2. The turbine-driven pump segment includes the turbine, trip and throttle valve, governor assembly with the associated controls, the turbine steam supply isolation just upstream of the trip throttle valve, and the valve operators. Also included with this segment are the pump and associated piping from and including the suction isolation 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.

3. The turbine steam supply segment includes the associated piping, valves, and valve operators from the main steam line penetrations (but not including) to the turbine steam supply isolation valve. The instrument air supply and dc power to the solenoid operated valves were excluded.

4. The turbine-driven pump feed control segment includes the piping and valves from the pump discharge isolation up to the steam generator for plants with only one AFW injection header per steam generator or plants where AFW has no connection with the main feedwater system. For plants with more than one injection header per steam generator or AFW connects with the main feedwater system, the turbine-driven pump feed control segment includes the pump discharge isolation valve and upstream piping up to the connection point for the alternate injection path or main feedwater system. Included with the segment are the associated valves and valve operators, the flow control valve and the control logic, and the test recirculation line where applicable.

5. The electric-motor driven pump segment includes the motor and associated breaker at the power board (excluding the power board itself). Also included with this segment are the pump and associated piping from and including the suction isolation 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.

6. The electric-motor driven pump feed control segment includes the piping and valves from the pump discharge isolation up the steam generator for plants with only one AFW injection header per steam generator or plants where AFW has no connection with the main feedwater system. For plants with more than one injection header per steam generator or AFW connects with the main feedwater system, the electric-motor driven pump feed control segment includes the pump discharge isolation valve and upstream piping up to the connection point for the alternate injection path or main feedwater system. Included with the segment are the associated valves and valve operators, the flow control valve and the control logic, and the test recirculation line where applicable

7. The diesel-driven pump segment includes the diesel engine, the associated fuel oil including the day tank, diesel cooling water back to the supply isolation and the governor, and the engine starting system. Also included with this segment are the pump and associated piping from and including the suction isolation 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.

8. The diesel-driven pump feed control segment includes the piping and valves from the pump discharge isolation up to the steam generator for plants with only one AFW injection header per steam generator or plants where AFW has no connection with the main feedwater system. For plants with more than one injection header per steam generator or AFW connects with the main feedwater system, the diesel-driven pump feed control segment includes the pump discharge isolation valve and upstream piping up to the connection point for the alternate injection path or main feedwater system. Included with the segment are the associated valves and valve operators, the flow control valve and the control logic, and the test recirculation line where applicable.

9. The common feed control segment applies to plants where the turbine/diesel and electric-motor-driven pumps discharge to a shared header with flow to the steam generator being regulated in the common header. This segment includes the piping and valves from (but not including) the pump discharge isolation up to the steam generator for plants with only one AFW injection header per steam generator or plants where AFW has no connections with the main feedwater system. For plants with more than one injection header per steam generator or AFW connects with the main feedwater system, the feed control segment includes the pump discharge isolation valve and upstream piping up to the connection point for the alternate injection path or main feedwater system. Included with this segment are the associated valves and valve operators, the flow control valve and the control logic, and the test recirculation line where applicable.

10. The steam generator feed segment includes the check valve(s) and associated piping downstream of the common or turbine/motor feed segments. This segment generally includes the last check valves in the feedwater system piping that prevent short cycling of AFW flow to the main feedwater system.

The Instrumentation and Control subsystem includes the circuits for the system initiation, operation, and the containment isolation function of the AFW turbine steam lines. However, each of the component failures in these circuits were screened to ensure that the failed component identified in the circuit was dedicated to the AFW system. Instrumentation and Control failures are implicit in the segment boundaries. That is, the segment affected by this type of failure would be recorded as a segment failure caused by instrumentation and control.

Additional components that were considered to be part of the AFW system are the circuit breakers at the motor control centers (MCCs) (but not the MCCs themselves). Heating, ventilating, and air conditioning systems and room cooling associated with the AFW system were also included. Losses of a specific AFW room cooler are included, but not failures within the service water system.

AFW system failures caused by support system failures were included in this AFW study. Support system failures were defined as failures of systems that affect the operation of the AFW system. These systems included, but were not limited to, 4160 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 AFW 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. Qualitative discussions concerning the overall contribution of support system failures for system unreliability are provided in Section 3 and the mechanisms of the failures in Section 4.

2.2 Collection of Plant Operating Data

The AFW system operational data used in this report are based on LERs residing 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 AFW system for the years 1987 through 1995. To ensure as complete a data set as possible, the SCSS database was also searched for all safety injection actuations and critical reactor trips for plants that have an AFW system. These records would provide an additional source of AFW actuations because (1) the AFW system is typically demanded as a result of safety injection demand and (2) AFW may be required to start following a reactor trip as a result of either steam generator level shrink or feedwater problems experienced as part of the trip.

Differences may exist among plants in interpreting what is an AFW ESF actuation or failure and hence what is reportable. 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 AFW 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.*[49] (AFW ESF actuations were found to be reported as ESF actuations for all plants in the study.) AFW 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) provide a more complete description, thus making it easier to determine whether the AFW 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 both actual and potential AFW failures during all plant operating conditions and testing. In this report, the term *inoperability* is used to describe any AFW 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, after considering all the data provided in the full text of the LER, the segment would not have functioned successfully for the assumed mission. The subset of inoperabilities not classified as failures were primarily potential failures (e.g., late performance of surveillance tests, missing seismic restraints, missing missile protection, etc.).

The AFW 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 AFW system consists of redundant trains, not all train level inoperabilities are captured in the LER data. Specifically, plants are not required to report single train inoperabilities 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, an electric-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 removed any surveillance test data from being considered for the unreliability estimate. However, for ESF actuations, all component failures that occurred as part of or in conjunction with 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 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-2.2 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. The full text of all selected LERs was subject to an independent review by a team of experienced U.S. commercial nuclear power plant personnel, with care taken 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 this review. Specifically, the information necessary for determination of reliability in this report, such as, classification of AFW failures, failure mode, failure mechanism, and cause, was based on the independent review of the selected LERs. Again, the SCSS data search was used only to identify those LERs applicable to this study; no data characterization, evaluation, or reliability analysis was performed on 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 missions were: (1) a risk-based mission which assumes the system must operate successfully for a 24 hour period as identified in the PRA/IPEs; (2) an operational mission which requires the system to operate as long as it is needed following a plant transient. The operational mission requirements vary based on the type of transient experienced by the plant. Typically the operational missions require system operation from only a few minutes up to several hours. Failure classification of the events for a risk-based mission was based on the ability of the AFW system to function as designed for at least 24 hours. Inoperability events classified as failures for an operational mission were based on successful operation while the system was needed. Thus, events could be classified as failures for a risk-based mission even if the system functioned successfully for the operational mission. Therefore, these events would be included in the failure count for a risk-based mission, but would not be included in the failure count for an operational mission. An example of such a failure would be a turbine governor oil leak that would allow the turbine to operate while it was needed to restore steam generator level (15 minutes). However, the oil leak would fail the turbine, and hence the pump, in a longer 24 hour risk-based mission. Each LER was reviewed to determine if the segment would have been reasonably capable of performing its safety function for each mission.

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 AFW system to complete its mission. Specifically, an electric-motor-driven pump segment may have failed to start; however, the turbine-driven and/or other electric-motor-driven pump segment may have responded as designed for the mission. Hence, the system was not failed. For the purposes of this study, the following segment failure modes were observed in the operational data:

- Maintenance out of service (MOOS) occurred if, because of maintenance activities, the segment was prevented from starting automatically during an unplanned demand. This failure mode only applied to the pump segments (diesel, turbine, and electric motor) since these were the only segments identified in the LERs where the segment was not available to automatically start during unplanned demands.

- Failure to start (FTS) occurred if the pump segment was in service but failed to automatically start or manually start, and generate sufficient pressure and flow. This failure mode applied only to the pump segments (diesel, turbine, and electric motor).

- 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. This failure mode applied only to the pump segments (diesel, turbine, and electric motor).

- Failure to operate (FTO) occurred if the segment (other than pump train segments) could not perform its required design function when needed.

- Common cause failure (CCF) occurred if two or more segments could not perform their required safety function as a result of a similar failure mechanism.

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

Recovery from initial failures is another factor 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 turbine-driven pump tripped on overspeed (electric) and (b) manually resetting the electric overspeed trip from the control room, thereby causing the turbine trip throttle to reset and the turbine to restart. Each failure during an unplanned demand was evaluated to determine whether recovery by the operator occurred.

There were also some failures from which operators elected not to recover because a redundant segment of the AFW system was successful. For example, if the turbine-driven pump tripped on overspeed during start and both motor-driven pumps were operating properly, the operators may not have elected to recover the failed turbine-driven pump. To eliminate any potential bias in the estimates of the recovery probabilities, failures that were not attempted to be recovered were further analyzed to determine if they could have been recovered. If the failure mechanism was such that recovery was possible, but the redundant segments of AFW were successful, the failure was judged to be recoverable.

For the events not classified as failures, the analysis section of each LER can provide information to aid in 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 not to have the required number of seismic restraints, and therefore was not considered operable as defined by plant technical specifications. However, if the results of an engineering analysis for the missing restraints provided by the plant in the safety analysis section of the LER indicated that the existing system configuration would not have failed given a seismic event, then the event was not classified as a failure.

In addition, administrative problems associated with AFW were also 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 assumption that, given a demand for the segment, the segment would be capable of performing its design function. Moreover, plant personnel typically would state in an LER that the segment was available to respond and that the subsequent surveillance test was performed satisfactorily. If it was stated that the segment failed the subsequent surveillance test, that event was 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 AFW 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 stem primarily from the reportability requirements identified for the LER and the exclusion of events where the failure mechanism is outside the AFW 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. Appendix C provides a listing and summary of the events used in estimating the unreliability of the AFW system.

2.2.3 Characterization of Demand Data

To estimate reliability, information on the frequency and nature of AFW demands was needed. For the purposes of this study, a 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. Spurious signals or those inadvertent initiation signals that occurred during the performance of a surveillance test were not classified as demands. An unplanned demand is defined as either a manual or automatic initiation of the system or segment that was not part of a pre-planned evolution. Unplanned demands were typically the result of actual low steam generator water level conditions, safety injection demands, or losses of normal feedwater. Other plant conditions may have also resulted in an unplanned demand of AFW based on the plant-specific design of the AFW initiation circuit. These initiations of AFW were also included in the study if they resulted from a valid signal.

The LERs identified from the SCSS database search were reviewed to determine the nature and frequency of AFW unplanned demands. Specifically, 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 schematic for AFW was 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 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 AFW based on the information provided in the IPE or FSAR. For example, the plant would state in the LER that a double-low water level condition existed in two steam generators during the event. Based on the information provided in the FSAR for the particular plant, the condition would result in the automatic start of both electric-motor-driven pumps and the turbine-driven pump. However, no explicit identification of the AFW pump start was found in the LER. Therefore, based on the narrative of each LER and plant-specific knowledge concerning AFW initiation and operation, it was possible to determine a relatively accurate number of AFW unplanned demands throughout the industry, even though not every demand was explicitly identified in the LER. 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

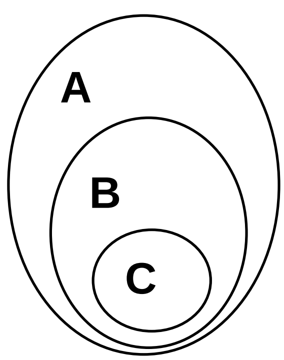
18-month surveillance tests simulate automatic actuation of the system throughout its safety-related operating sequence and that each automatic valve actuate to the correct position. In addition to the 18-month surveillance tests, quarterly surveillance tests of the pumps that are required to be performed per ASME Section XI could also be used to estimate reliability. Because both of these tests are performed at a relatively standard frequency and place approximately the same stresses on the system as an actual plant transient, they could be used to estimate a demand frequency and subsequent reliability estimate of the system for a risk-based mission. 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 AFW unplanned demands will differ from the number of ESF actuations identified in a simple SCSS database search. This difference results from 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 AFW ESF actuations, while in this study, the intent was to capture all actual AFW 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 based on 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 the 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, countable failures.

Data Set C, which consists of the countable failures, provides the basis for estimating the unreliability of the AFW 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.



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.

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 AFW system performance and not calculate quantitative estimates of unreliability. Therefore, the engineering analysis uses both the faults and failures appearing in the operational data. That is, the engineering analysis focused on Data Set A and B, which includes Data Set C, with an engineering analysis of the factors affecting AFW system unreliability.

3. RISK-BASED ANALYSIS OF THE 1987–1995 EXPERIENCE

This section documents the results of the reliability analyses performed using the AFW 1987–1995 experience in two ways. First, estimates of AFW unreliability for the actual missions experienced were calculated. These unreliability estimates are based on the AFW missions that result from routine transients including a normal reactor trip in which main feedwater is commonly isolated, producing a low level in the steam generators and a demand for auxiliary feedwater. These demands for AFW operation can range from a few minutes (when main feedwater is immediately returned to service) to a few hours (when the plant operators rely on AFW and don't restore main feedwater). The estimates of AFW system unreliability for this operational-based mission were analyzed to uncover trends and patterns in system performance on a plant-specific and industry-wide basis.

Second, AFW system unreliability was estimated using the 1987–1995 experience, but this time for conditions typically assumed in a PRA. In this case, the AFW system is required to respond to loss of main feedwater, and generally assumes a 24-hour run time requirement for the AFW system. This was done for comparison to AFW unreliabilities were also calculated using the fault trees but using the AFW component failure data reported in PRA/IPEs (see References 1 through 48). 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 all 72 operating PWR plants. The PWRs that were permanently shut down at the time of this study (i.e., Trojan, San Onofre Unit 1, Rancho Seco, and Yankee Rowe) are not included in this study.

AFW 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 AFW fault tree logic models were not available in the PRA/IPEs, since these were not required to be submitted to the NRC. However, the component failure probabilities used in calculating AFW unavailability were documented. AFW unreliabilities were calculated using the AFW 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 1987–1995 experience. The component failure probabilities extracted from the PRA/IPEs were generally those identified as the major contributors to AFW unavailability. Therefore, the PRA/IPE estimates approximated for this study are likely to be different but not significantly, from those used in PRA/IPE quantification.

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

The following is a summary of the major findings:

- Based on the data found in the 1987–1995 experience, there were no failures of the entire AFW system identified in 1,117 unplanned system demands. A simple Bayes estimate of the AFW system unreliability using this data is 4.5E-04 with associated 90% uncertainty interval (1.8E-06, 1.7E-03). Using a system level fault tree model that combines individual failure modes, the operational unreliability of the AFW system calculated by arithmetic averaging the results of 72 plant-specific models is 3.4E-05. Individual plant results vary over two orders of magnitude, from 1.5E-06 to 6.2E-04. The variability reflects the diversity in AFW system designs. However, there is variability in results among plants with similar AFW designs (factors of twenty between highest and lowest AFW unreliabilities). This is attributed to the plant-to-plant differences in the 1987–1995 experience and to a lesser degree, differences in the levels of redundancy in the feed control/injection headers (note this design feature was not a determining factor when plants were grouped into similar design classes for the purpose of this analysis). Section 3.2.5 discusses the within design class differences.

- Based on the average of the eleven reference plants, CCF is the leading contributor to the operational unreliability. Generally, the importance of CCF is typical of redundant train systems that are highly reliable. The CCFs identified in the 1987–1995 experience were failures of the feed control/injection segments, failures of redundant motor trains, and a CCF involving a motor and turbine pump (failure of the pump unit to run). Based on AFW operational unreliability, AFW systems comprised of three or more trains are more likely to fail as a result of CCF. While AFW systems with only two levels of redundancy are more likely to fail as a result of random multiple independent failures. See Section 3.2.2 for additional information.

- The review of the 1987–1995 experience found no support system failures that disabled the entire AFW system. However, six instances of a motor-driven AFW pump failing to start automatically because of support system problems (typically as a result of the solid-state protection system undergoing test at the time of the demand) were identified. The effect of including these non-dedicated support system failures on AFW system reliability estimates are negligible since all of these failures were quickly recovered. Section 3.5 provides the results of the sensitivity of support system failures on AFW unreliability.

- While not probabilistically important, inappropriate operator intervention in the operation of at least one train (and in one instance the entire system) was identified in the 1987–1995 experience. These human errors consisted of shutting down or disabling AFW equipment after it had started. Section 3.4 discusses the operator action that disabled the entire AFW system.

- AFW designs comprised of only turbine-driven pumps are the least reliable, while AFW designs comprised of three redundant trains with diversity (two motor and one turbine) are more reliable. AFW designs consisting of four trains (three motor and one turbine) are not significantly different in reliability terms as the two motor and one turbine pump designs. The benefits of additional trains of redundancy to AFW system reliability is offset by the effects of common cause failures. Although the AFW designs consisting solely of turbine-driven pumps tend to be less reliable in routine operations, consideration of potential station blackout situations may yield different results. The relatively good performance of one motor and one diesel pump designs (Design Class 7) might be attributable to the sparse data available for the diesel-driven pumps. Since no failure-to-run events were observed for this pump, this particular failure mode was not included in the model. See Section 3.2.3 for additional details.

- Generally, the turbine-driven pump trains are about a factor of 10 less reliable than motor-driven pumps trains and a factor of four less reliable than the diesel driven pump trains. There is no appreciable plant-to-plant variation within the driver-specific pump train unreliabilities, which further supports the observation that AFW system unreliability (based on the 1987–1995 experience) is mostly influenced by the levels of redundancy and diversity in the specific system design (see Section 3.3.3).

- The leading contributors to AFW operational unreliability vary depending on the AFW design class. These are briefly described below and in detail in Section 3.2.4.

  - For AFW designs consisting of three or more pump trains with diversity in drivers, common cause failure (CCF) accounts for 72% to 99% of AFW operational unreliability. The major CCF contributors to these configurations are CCF of the pumps (excluding the driver) failing to run and CCF of discharge segments failing to operate (not in the order of importance). The three turbine train configuration is most affected by CCF of the turbine steam supply (92%), followed by independent failure to start of the turbines, CCF of the discharge segments, and CCF of the pumps to run (excluding the driver).

  - For AFW designs composed of two pump trains, multiple independent failures of the pumps are the leading contributors to operational unreliability, approximately 71% to 96%. Specifically, for the two turbine train system, leading contributors are combinations of multiple independent turbine failures (approximately 80%), with failure to start of the turbine as the dominant failure mode, followed by CCF of the turbine steam supply (approximately 20%). For the diverse two train configuration (i.e., one motor and one turbine or one diesel) the dominant independent failure mode is failure to start of the turbine, motor, or diesel, while the dominant CCF mode is the pumps failing to run.

- No trends were identified in the AFW operational mission unreliability when plotted against low-power license date or calendar year. The trends are not statistically significant at the 5% significance level. Section 3.2.6 provides the information on the unreliability trends.

- The industry-wide arithmetic average of AFW system unreliability for a PRA mission calculated using data extracted from PRA/IPEs is 3.4E-04. The corresponding estimate based on the 1987–1995 experience is 2.1E-03 or about a factor of six greater than the average of the PRA/IPE values. Both of these estimates do not account for non-safety trains and equipment available at some plants (for example, the use of non-safety grade startup feedwater pumps as backups to AFW). The major differences between the two estimates are attributable to the probabilities associated with failure of the primary AFW system water source (e.g., CST suction path, generally not considered as being important from a probability viewpoint in most PRA/IPEs, but observed in the 1987–1995 experience) and the AFW turbine-driven pump failure to run failure rates were significantly higher when using the relatively limited 1987–1995 experience. Sections 3.3.2 and 3.3.3 provides the results and insights for comparison with PRA/IPE results.

3.1 AFW Unreliability Data and System Modeling

Estimates of AFW unreliability were calculated using the unplanned demands reported in the LERs. Testing data were not used as part of the 1987–1995 experience because of concerns about the reportability of test failures involving redundant train systems. Failures involving total system failure are required to be reported, 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. 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 AFW system from support systems outside the AFW boundary defined in Section 2.1.3 are excluded from the failure counts.

The failures identified for the AFW 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, and feed control/injection header failing to operate. The maintenance-out-of-service, failure to start, and failure to run modes were further broken down into pump-driver specific failure modes to provide additional insights into the reliability of the AFW 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 plant was operating 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 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. All data collected for this study (excluding CCF Database data) were initially analyzed by plant, by year, and by source. Each data set was modeled as a binomial distribution with confidence intervals based on sampling uncertainty. Various statistical tests (Fisher's exact test, Pearson chi-squared test, etc.) were then used to test the hypothesis that there is no difference between the types and sources of data.

Because of concerns about the appropriateness and power of the various statistical tests and the possibility that there are real physical differences between plants, an empirical Bayes method to model variation was attempted regardless of the results of the statistical testing for differences. The simple Bayes method was used only if no empirical Bayes could be fitted. [For more information on this aspect of the data analysis, see Appendices A and E (Sections A-2.1 and E-1.1)]. In the simple Bayes case, the uncertainty in the calculated failure rate is dominated by random or statistical uncertainty (also referred to as *sampling* uncertainty). The simple Bayes essentially pools the data and treats it as a homogeneous population. On the other hand, if an empirical Bayes distribution was fitted, then the uncertainty was dominated by the *plant-to-plant* (or year-to-year) variability. That is, the data were not pooled, and individual plant or year-specific failure probabilities were calculated based on the factor that produced the variability.

3.1.1 Recovery of AFW Failures

Given that a failure has occurred in the AFW 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 1987–1995 experience where actual diagnosis and repair of AFW 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 AFW unreliability include the effects of recovery. However, due to the redundancy of the AFW 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 1987–1995 experience. The review of the 1987–1995 experience identified no instances where the human failed the recovery attempt where simple recovery was possible. Since, there were no events identified in the 1987–1995 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.

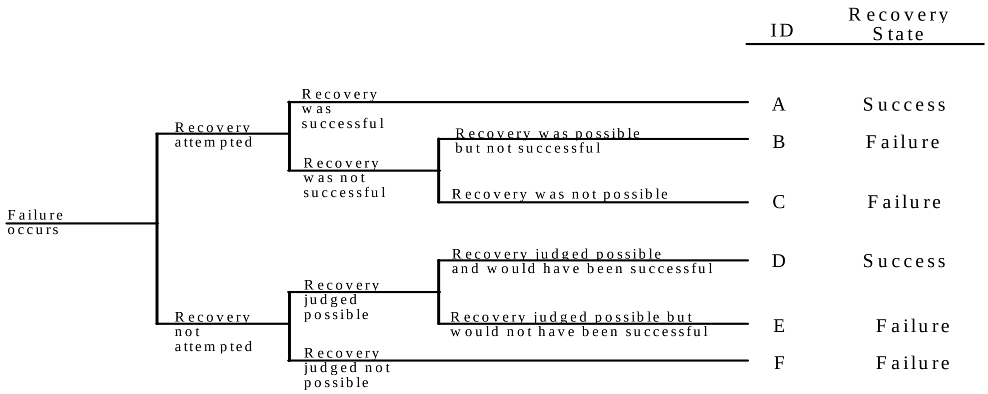


Figure 3. The recovery tree depicting the outcomes of recovering an AFW failure. The tree is based on the recovery actions observed in the unplanned demand data. Path B had no events of this type. Path E was assumed to have no likelihood based on Path B results.

3.1.2 Failure and Demand Counts used in the Unreliability Estimation

The failure and demand counts used for estimating probabilities for the AFW system failure modes are identified in Table 2. The demand counts identified in Table 2 represent opportunities for AFW system success. Due to the various designs and operational differences of the AFW system, a demand for AFW may only contribute to a specific pipe segment of the system. No direct correlation of the segment demands to AFW system actuations is possible based solely on the information contained in the LERs. Therefore, piping diagrams and the design operation of the AFW 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. For some failure modes, failures were classified as either pertaining to an operational mission or for comparison with PRA/IPE results. This distinction was made since some events succeeded for a short-term operational mission but would have obviously failed during a longer duration event. The counts in Table 2 are summarized below:

- There were 2,662 unplanned pump train segment (i.e., motor, turbine, and diesel) demands that occurred while operating. For the motor train, there were 1,995 demands that resulted in four trains being out of service for maintenance at the time of the demand. For these failures, two were recovered. Similarly, for the turbine train, five out-of-service failures (three were not recovered and two were judged to be recoverable) occurred in 602 demands. The diesel train had no maintenance-out-of-service failures identified in 65 demands.

- The suction segment provides the preferred source of water, typically from the Condensate Storage Tank, to the AFW pump trains. There were 1,116 demands for the suction segment to supply water to a pump train suction. Only one failure was identified for the suction segment, and it is applicable only for comparison with PRA/IPE results. The single failure identified was recovered.

There were 1,993 opportunities for a motor train to start due to unplanned demands. These demands resulted in six failures to start of the motor train. For the turbine train, a main steam supply segment (typically redundant steam supply headers) needs to admit steam to the turbine trip/throttle valve. There were 1,108 valve demands for the steam supply valves

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

Failure Mode	Unplanned Demands	
	f [a]	*d* [a]
Maintenance-out-of-service while not shut down—motor train (MOOS-M)[b]	4	1,995
Failure to recover, motor train maintenance MOOS-M	2	4
Maintenance-out-of-service while not shut down—turbine train (MOOS-T)[b]	5	602
Failure to recover, turbine train maintenance MOOS-T	3	5
Maintenance-out-of-service while not shut down—diesel train (MOOS-D)[b]	0	65
Failure to operate, suction path faults (FTO-SUC)	0 (1[c])	1,116
Failure to recover, suction path faults FTO-SUC	0	1
Failure to start, motor pump/valve train path (FTS-M)	6	1,993
Failure to start, turbine pump/valve train path (FTS-T)	16 (17[c])	597
Failure to start, diesel pump/valve train path (FTS-D)	1	65
Failure to recover from motor FTS-M	1	6
Failure to open turbine steam supply (FTS-ST)	1	1,108
Failure to recover turbine steam supply FTS-ST	1	1
Failure to recover from turbine FTS-T	8 (8[c])	16 (17[c])
Failure to recover from diesel FTS-D	0	1
Failure to run, motor pump/valve train path (FTR-M)	1	1,987
Failure to recover, motor pump/valve train path FTR-M	1	1
Failure to run, turbine pump/valve train path (FTR-T)	2 (3[c])	583
Failure to recover, turbine pump/valve train path FTR-T	2 (3[c])	2 (3[c])
Failure to run, diesel pump/valve train path (FTR-D)	0 (1[c])	65
Failure to recover, diesel pump/valve train path FTR-D	1	1
Failure to operate feed control/injection header (FTO-INJ)	22	5,226
Failure to recover feed control/injection header FTO-INJ	11	22
Failure to operate, steam generator header (FTO-SG)	0	2,148

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

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

c. The first value represents the operational mission, while the second value is for comparison with PRA/IPE results (e.g., 24 hour mission time).

(FTS-ST). Only one of the redundant headers was lost due to valve failure. Therefore, the turbine still had the opportunity to succeed since steam was still supplied by the redundant header. There were 597 turbine train opportunities to start as a result of the unplanned demands with 16 failures to start for the operational mission (17 for comparison with PRA/IPE results). For the diesel train, there were 65 opportunities to start with one failure identified.

- Among the start failures, several were recovered or were recoverable. Of the six FTS-M, four were recovered, one was judged to be recoverable (path D outcome in Figure 3), and one was not recovered. For FTS-T, three were recovered (four for comparison with PRA/IPE results), five were judged to be recoverable (path D outcome in Figure 3), and eight were not recovered. The one FTS-D failure was recovered.

- For the run phase of the AFW system operation, there was one failure of the motor train that was not recovered in the 1,987 unplanned demands. The FTR-T counts were two failures for the operational mission (three failures for comparison with PRA/IPE results) in 583 demands. For the diesel train, there were no failures in 65 demands for an operational mission. However, there was one event where the diesel train successfully completed its operational mission, but would have failed. Therefore, for the operational mission, there were no failures of the diesel train, while one failure is recorded for comparison with PRA/IPE results.

- None of the FTR events in the operating experience were recovered.

- The network of redundant injection headers downstream of the pump/valve trains received an estimated 5,226 opportunities to direct/control flow to a steam generator. Of the injection header demands, 22 failures to operate were identified within this pipe/valve segment. Of the 22 failures, eleven were not recoverable.

- The steam generator segment consists of the piping segments that contains only the check valves immediately upstream of the steam generator. There is no direct correlation of this segment to the number of feed control/injection header demands. There were 2,148 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 AFW pump trains and feed control/injection trains, common cause failures (CCFs) were considered. CCF was explicitly included in the AFW unreliability model because CCF events were found in AFW failure data between 1987–1995. 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 AFW system was conducted in several stages and accomplished in conjunction with the CCF Database[50] program. First, the LERs (both unplanned demand and surveillance test for the 1987–1995 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 AFW system included events identified in the 1987–1995 time period that contributed to failure of redundant segments. Based on the 1987–1995 unplanned demand data, CCF events were identified for the motor-driven pump trains failing to start; the pumping unit (independent of driver) failing to run; and, the injection headers failing to operate. To further evaluate the susceptibility of AFW to CCF, the surveillance test data contained in the LERs were screened to identify additional CCF mechanisms. One additional event, failure of the turbine train steam supply valves to open, was identified in the surveillance test data as a viable CCF failure mechanism.

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 AFW 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 1987–1995 experience, the Alpha factors for the turbine failing to start are included in Table 3. The turbine failing to start Alpha factors are provided to complement the turbine information although not found in the 1987–1995 experience. They are intended to provide the reader and user of this document with a consistent set of CCF parameters for the AFW turbine train.

The CCF failure probability estimates calculated by the Alpha factor methodology were compared to direct or simple estimates derived from the 1987–1995 experience. The two methods resulted in estimates that compared well and were reasonable.

3.1.4 AFW System Fault Tree Models

The fault tree models for the eleven design classes shown in Figure 4 illustrate the logic used for generating the 72 plant-specific AFW unreliability models. Plant-specific models were generated since there are some differences in the AFW configurations within a design class. These differences are described in Section D-2 of Appendix D.

3.2 AFW Unreliability for an Operational Mission

This section documents the results of the reliability analyses performed using the AFW 1987–1995 experience. Estimates of AFW unreliability for the actual missions experienced were calculated. These unreliability estimates are based on the AFW missions that result from routine transients including a normal reactor trip in which main feedwater is commonly isolated, producing a low level in the steam generators and a demand for auxiliary feedwater. These demands for AFW operation can range from a few minutes (when main feedwater is immediately returned to service) to a few hours (when the plant operators rely on AFW and don’t restore main feedwater). This information related to these events are referred to as belonging to an operational mission (i.e., AFW operational unreliability).

3.2.1 AFW System Modeling Assumptions for an Operational Mission

The fault tree models for the eleven design classes shown in Figure 4 provided the logic used for generating the 72 plant-specific AFW unreliability models. The eleven AFW design class models were developed to categorize the levels of steam generator, and pump train redundancy and diversity across the industry. Plant-specific models were developed from the eleven models to identify differences in the feed control/injection path redundancy within a design class. These differences are described later in Section 3.2.5. The unreliability of the AFW system was calculated for an operational mission 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 AFW piping segments. In most cases, the models used the 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. Since LERs are not required to be submitted for these types of pump trains, estimates for these types of non-safety components were not calculated.

Table 3. Estimates of Alpha factors based on the 1987–1995 experience used for calculating the AFW unreliability.

Event Name	Distribution	Alpha Factor Mean and 90% Interval	Description
ALPHA-FTS	Beta(2.0, 6.93E+01)	(5.1E-03, 2.8E-02, 6.6E-02)	2 of 2 motor-driven pumps fail to start
ALPHA-FTS	Beta(1.6, 9.94E+01)	(2.1E-03, 1.6E-02, 4.0E-02)	3 of 3 motor-driven pumps fail to start
Alpha factor for 2 of 2 turbines failure to start[a]	Beta(1.0, 1.47E+01)	(3.5E-03, 6.8E-02, 2.0E-02)	2 of 2 turbine-driven pumps fail to start
Alpha factor for 3 of 3 turbines failure to start[a]	Beta(4.8E-01, 2.15E+02)	(6.6E-06, 2.2E-03, 8.6E-03)	3 of 3 turbine-driven pumps fail to start
ALPHA-FTR	Beta(1.0, 8.45E+01)	(6.9E-04, 1.2E-02, 3.6E-02)	2 of 2 pumps fail to run; excludes driver
ALPHA-FTR	Beta(3.8E-01, 1.21E+02)	(2.3E-06, 3.1E-03, 1.3E-02)	3 of 3 pumps fail to run; excludes driver
ALPHA-FTR	Beta(2.9E-01, 1.56E+02)	(1.6E-07, 1.9E-03, 8.6E-03)	4 of 4 pumps fail to run; excludes driver
ALPHA-DISSEG	Beta(1.7, 9.48E+01)	(2.6E-03, 1.8E-02, 4.4E-02)	2 of 2 feed segment flow control valves fail to operate
ALPHA-DISSEG	Beta(3.5E-01, 1.37E+02)	(1.1E-06, 2.6E-03, 1.1E-02)	3 of 3 feed segment flow control valves fail to operate
ALPHA-DISSEG	Beta(2.5E-01, 1.80E+02)	(1.8E-08, 1.4E-03, 6.6E-03)	4 of 4 feed segment flow control valves fail to operate
ALPHA-DISSEG	Beta(3.8E-01, 2.59E+02)	(1.1E-06, 1.5E-03, 6.2E-03)	6 of 6 feed segment flow control valves fail to operate
ALPHA-DISSEG	Beta(8.0E-02, 3.30E+02)	(<1.0E-08, 2.4E-04, 1.4E-03)	8 of 8 feed segment flow control valves fail to operate
ALPHA-STM	Beta(1.5, 1.62E+01)	(1.1E-02, 8.5E-02, 2.1E-01)	2 of 2 steam supply valves to turbine fail to open

a. The Alpha factor is not used in the quantification of the AFW fault tree. The parameter estimates are provided only for additional CCF information for the AFW turbines.

Figure 4. System fault trees of the eleven AFW design classes used in calculating unreliability.

Figure 4. (continued).

Figure 4. (continued).

Figure 4. (continued).

Figure 4. (continued).

Figure 4. (continued).

Figure 4. (continued).

Figure 4. (continued).

Figure 4. (continued).

Figure 4. (continued).

Figure 4. (continued).

Estimates of AFW unreliability were calculated using the 1987–1995 experience. These data were statistically analyzed to develop failure probabilities (see Appendices A and E for the details on the statistical applications and methods). The following failure modes are based on the 1987–1995 experience:

- Failure to Start—Turbine-driven pump steam supply valves and associated piping (FTS-ST)
- Failure to Start—Pump, driver, valves and associated piping (FTS)
- Failure to Run—Pump, driver, valves and associated piping (FTR)
- Maintenance-out-of-service—Pump, driver, valves, and associated piping (MOOS)
- Failure to Operate—Feed control/injection header valves (AFW feed control/isolation, etc.) and associated piping faults (FTO-INJ).

Table 4 contains the failure mode probabilities and associated uncertainty intervals calculated from the 1987–1995 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 to provide auxiliary feedwater to a steam generator is received by the AFW system.
- The FTR contribution to the unreliability is estimated on a per mission demand.
- The condensate storage tank is assumed to meet all needs for auxiliary feedwater. Alternate suction sources are not modeled.

3.2.2 Estimates of AFW Operational Unreliability and Insights

Plant-specific estimates of AFW operational unreliability were calculated due to plant-to-plant variability in the data and due to the design variations of the AFW systems within certain design classes. A plot of the plant-specific estimates of AFW operational unreliability is provided in Figure 5. The plant-specific estimates are grouped according to AFW design class. The average of the 72 plant-specific estimates of AFW operational unreliability is approximately 3.4E-05. This average, which is based on the plant-specific estimates, was compared to a simple system (complete) performance estimate calculated directly by using a Jeffreys noninformative prior. The overall system reliability estimate is 4.5E-04 (based on no total system failures in 1,117 demands). The 90% uncertainty interval on the Jeffreys estimate is 1.8E-06, 1.7E-03. Generally the plant-specific estimates fall within the 90% uncertainty interval calculated for the overall system reliability estimate. Only eight of the 72 plant-specific estimates lie below the lower 5%, while none of the estimates were above the 95% uncertainty.

The contributions of failures to the overall AFW operational unreliability are presented in Table 5. The contributions are calculated according to the cut set contribution to the operational unreliability for the reference plant selected for each design class. (Table D-11 provides the listing of the cut sets for the eleven reference plants.) Based on the average of the eleven reference plants, CCF is the leading contributor to the operational unreliability. Generally, the importance of CCF is typical of redundant train systems that are highly reliable. Based on AFW operational unreliability, AFW systems comprised of three or more trains are more likely to fail as a result of CCF. While AFW systems with only two or less levels of redundancy are more likely to fail as a result of random multiple independent failures.

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

Failure Mode	f [a]	d [a]	Modeled Variation	Distribution	Bayes Mean and 90% Interval[b]
Unrecovered MOOS-M			Sampling	Beta(2.4, 2080.6)	(2.4E-04, 1.1E-03, 2.5E-03)
Maintenance-out-of-service while not shut down — motor train (MOOS-M)	4	1,995	Sampling	Beta(4.5, 1991.5)	(8.3E-04, 2.3E-03, 4.2E-03)
Failure to recover MOOS-M	2	4	Sampling	Beta(2.5, 2.5)	(1.7E-01, 5.0E-01, 8.4E-01)
Unrecovered MOOS-T			Plant	Beta(0.5, 105.1)	(1.7E-05, 4.6E-03, 1.8E-02)
Maintenance-out-of-service while not shut down — turbine train (MOOS-T)	5	602	Plant	Beta(0.6, 70.4)	(5.8E-05, 8.0E-03, 2.9E-02)
Failure to recover MOOS-T	3	5	Sampling	Beta(3.5, 2.5)	(2.6E-01, 5.8E-01, 8.7E-01)
Unrecovered FTS-ST			Sampling	Beta(1.2, 1156.1)	(7.5E-05, 1.0E-03, 2.9E-03)
Failure to open, turbine steam supply — (FTS-ST)	1	1,108	Sampling	Beta(1.5, 1107.5)	(1.6E-04, 1.4E-03, 3.5E-03)
Failure to recover turbine steam supply FTS-ST	1	1	Sampling	Beta(1.5, 0.5)	(2.3E-01, 7.5E-01, 1.0E+00)
Unrecovered FTS-M			Plant	Beta(0.1, 114.1)	(<1.0E-08, 8.1E-04, 4.7E-03)
Failure to start, motor pump/valve train path — (FTS-M)	6	1,993	Plant	Beta(0.1, 36.3)	(<1.0E-08, 3.8E-03, 2.1E-02)
Failure to recover from motor FTS-M	1	6	Sampling	Beta(1.5, 5.5)	(3.0E-02, 2.1E-01, 5.0E-01)
Unrecovered FTS-T			Plant	Beta(2.4, 171.2)	(3.0E-03, 1.4E-02, 3.1E-02)
Failure to start, turbine pump/valve train path — (FTS-T)	16	597	Plant	Beta(4.2, 153.1)	(9.6E-03, 2.7E-02, 5.1E-02)
Failure to recover from turbine FTS-T	8	16	Sampling	Beta(8.5, 8.5)	(3.1E-01, 5.0E-01, 6.9E-01)
Unrecovered FTS-D			Sampling	Beta(0.4, 75.2)	(9.5E-06, 5.7E-03, 2.3E-02)
Failure to start, diesel pump/valve train path — (FTS-D)	1	65	Sampling	Beta(1.5, 64.5)	(2.7E-03, 2.3E-02, 5.9E-02)
Failure to recover from diesel FTS-D	0	1	Sampling	Beta(0.5, 1.5)	(1.5E-03, 2.5E-01, 7.7E-01)
Unrecovered FTR-M			Sampling	Beta(1.2, 2073.4)	(4.2E-05, 5.7E-04, 1.6E-03)
Failure to run, motor pump/valve train path — (FTR-M)	1	1,987	Sampling	Beta(1.5, 1986.5)	(8.9E-05, 7.6E-04, 2.0E-03)
Failure to recover motor pump/valve train path FTR-M	1	1	Sampling	Beta(1.5, 0.5)	(2.3E-01, 7.5E-01, 1.0E+00)
Unrecovered FTR-T			Sampling	Beta(2.1, 594.4)	(6.9E-04, 3.6E-03, 8.3E-03)
Failure to run, turbine pump/valve train path — FTR-T)	2	583	Sampling	Beta(2.5, 581.5)	(9.8E-04, 4.3E-03, 9.5E-03)
Failure to recover turbine pump/valve train path FTR-T	2	2	Sampling	Beta(2.5, 0.5)	(4.3E-01, 8.3E-01, 1.0E+00)
Unrecovered FTO-INJ			Plant	Beta(0.2, 95.2)	(1.5E-08, 2.4E-03, 1.2E-02)
Failure to operate feed control/injection header — (FTO-INJ)	22	5,226	Plant	Beta(0.4, 97.1)	(6.2E-06, 4.3E-03, 1.8E-02)
Failure to recover feed control/injection header FTO-INJ	11	22	Plant	Beta(0.2, 0.2)	(1.4E-05, 5.6E-01, 1.0E+00)
Unrecovered total FTS probability for motor unit only (MDPS-FTS)			Plant	Beta(0.07, 23.0)	(<1.0E-08, 3.1E-03, 1.8E-02)
Total FTS probability for motor unit only (MDPS-FTS)	10	1,993	Plant	Beta(0.1, 14.2)	(<1.0E-08, 6.3E-03, 3.7E-02)
Failure to recover MDPS-FTS CCF events	1	2	Sampling	Beta(1.5, 1.5)	(9.7E-01, 5.0E-01, 9.0E-01)

Table 4. (continued).

Failure Mode	*f* [a]	*d* [a]	Modeled Variation	Distribution	Bayes Mean and 90% Interval[b]
Unrecovered total FTR probability for pump unit only (PMPS-FTR)			Sampling	Beta(1.2, 2749.5)	(3.2E-05, 4.3E-04, 1.2E-03)
Total FTR probability for pump unit only (PMPS-FTR)	1	2,635	Sampling	Beta(1.5, 2636.5)	(6.7E-05, 5.7E-04, 1.5E-03)
Failure to recover PMPS-FTR CCF events	1	1	Sampling	Beta(1.5, 0.5)	(2.3E-01, 7.5E-01, 1.0E+00)
Unrecovered total FTO-INJ probability (DIS-SEG)			Plant	Beta(0.6, 221.2)	(2.3E-05, 2.7E-03, 9.6E-03)
Total FTO-INJ probability (DIS-SEG)	28	5,226	Plant	Beta(0.8, 142.0)	(1.2E-04, 5.3E-03, 1.8E-02)
Failure to recover FTO-INJ CCF events	2	4	Sampling	Beta(2.5, 2.5)	(1.7E-01, 4.0E-01, 8.4E-01)
Total FTS-ST probability (TD-QT-STM)	1	1,108	Sampling	Beta(1.5, 1107.5)	(1.6E-04, 1.4E-03, 3.5E-03)

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

b. The values in parentheses are the 5% uncertainty limit, the Bayes mean, and the 95% uncertainty limit.

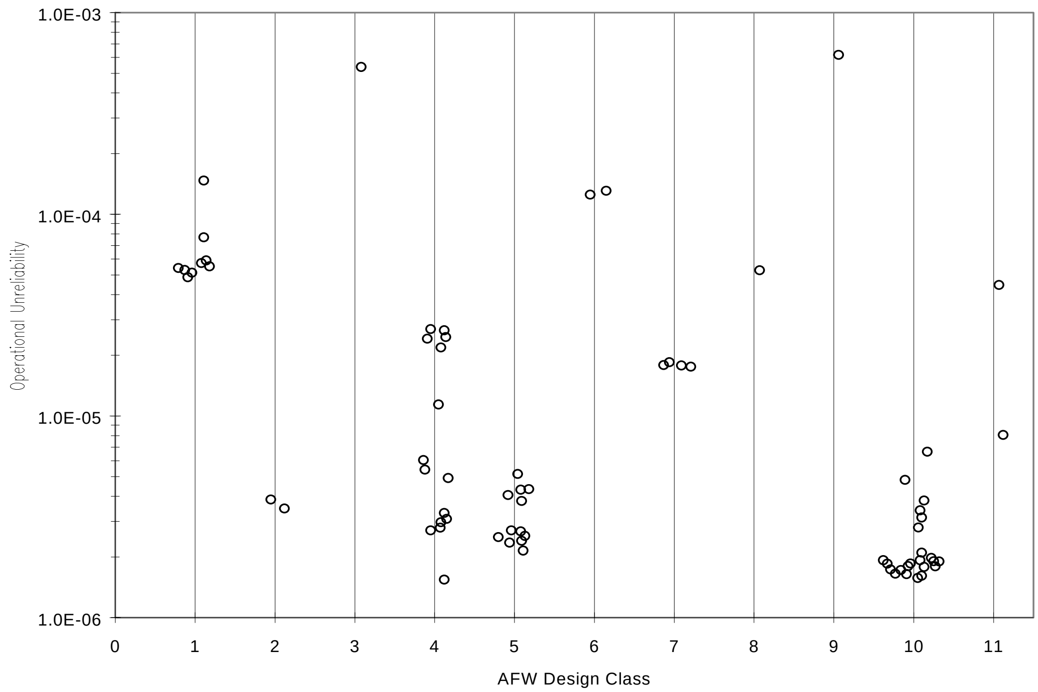


Figure 5. Plant-specific estimates of AFW system operational unreliability grouped by design class. Uncertainties are not plotted in order to provide better resolution of the plant-specific means. The uncertainties associated with the estimates are found in Table D-5 in Appendix D.

Table 5. AFW system cut set contribution (for the reference plant in each design class) to operational unreliability.

		Contribution (%) To Unreliability	
AFW Design Class	Reference Plant Operational Unreliability	Multiple Independent Failures	Common Cause Failure
1—(1M, 1T, 2SG)	1.5E-04	95.5	4.5
2—(1M, 2T, 2SG)	3.9E-06	28.5	71.5
3—(2T, 2SG)	5.4E-04	77.5	22.5
4—(2M, 1T, 2SG)	2.7E-06	8.2	91.8
5—(2M, 1T, 3SG)	2.7E-06	7.3	92.7
6—(3T, 3SG)	1.3E-04	5.5	94.5
7—(1M, 1D, 4SG)	1.9E-05	71.1	28.9
8 — (1M, 1T, 4SG)	5.3E-05	80.0	20.0
9—(2T, 4SG)	6.2E-04	80.5	19.5
10—(2M, 1T, 4SG)	2.0E-06	15.8	84.2
11— (3M, 1T, 4SG)	4.5E-05	0.1	99.9

The CCFs identified in the 1987–1995 experience were; failures of the feed control/injection segments (4 occurrences involving failure to operate), failures of redundant motor trains (2 occurrences related to failure to start), and one CCF occurrence involving a motor and turbine pump (failure of the pump unit to run). Section 4.2 describes the failure mechanisms associated with these events.

3.2.3 Pump Train Segment Operational Unreliability

The arithmetic average of all pump train segments (by driver) failure probabilities (FTS, FTR, and MOOS) calculated from the 1987–1995 experience is presented in Table 6. The minimum and maximum pump train segment failure probabilities are also shown in Table 6. A plot of the motor, turbine, and diesel-driven pump train unreliabilities calculated from the 1987–1995 experience and grouped by design class is shown in Figure 6. As seen in Figure 6, there is little variability in the pump train operational unreliability. However, there are a few plants with motor trains that have statistically significant higher failure probabilities. The high motor train failure probabilities are attributed to plant-to-plant differences in the failure to start mode. The higher turbine train failure probabilities are the result of variability in the maintenance out service failure mode.

The turbine-driven pumps are about an order of magnitude less reliable than the motor-driven pumps based on the 1987–1995 experience. However, for conditions encountered during station blackout, the turbine designs are more reliable since they do not rely on ac power.

The average failure probability for the turbine pump trains using 1987–1995 experience was compared to results of a past AEOD study (NUREG-1275[51]) of the reliability of steam-driven standby pumps. NUREG-1275 reviewed the AFW operational experience (LERs) for the period of 1974 through 1992 as well as NPRDS failure reports (1985 through 1992). Although the primary purpose of NUREG-1275 was to identify the failure mechanisms, reliability estimates of the standby AFW turbines were provided. NUREG-1275 calculated two failure probabilities for a standby AFW turbine-driven pump. These probabilities are 7.2E-02 and 6.5E-02. The 6.5E-02 probability excluded two maintenance unavailabilities, while the 7.2E-2 probability included all failures. The pump train estimates based on the 1987–1995 experience which includes contributions from MOOS is about a factor of three less than the 7.2E-02 estimate reported in NUREG-1275.

3.2.4 AFW Operational Unreliability Across Design Classes

Table 7 contains the arithmetic average of AFW operational unreliability with regard to design class. These results indicate that variability across the AFW system designs exists. The design class average unreliability range from 2.4E-06 (Design Class 10) to 6.2E-04 (Design Class 9). For AFW designs comprised of only two pump trains, multiple independent failures of the pumps are the leading contributors to operational unreliability, contributing 71% to 96%. Specifically, for the two turbine train configurations, combinations of multiple independent turbine failures (approximately 80%), with FTS of the turbine as the dominant failure mode followed by CCF of the turbine steam supply (approximately 20%), are the leading contributors. The diverse two train configuration (i.e., one motor and one turbine or one diesel) dominant failure modes are FTS of the turbine, motor, or diesel and CCF of the pumps failing to run, respectively.

Table 6. Pump train segment average failure probability calculated from the operating experience.

	1987–1995 Experience	
Pump Train	Arithmetic Average	Range
Motor-driven	2.5E-03	1.9E-03—8.5E-03
Turbine-driven	2.2E-02	1.9E-02—3.5E-02
Diesel-driven	5.7E-03	No plant-to-plant variation detected

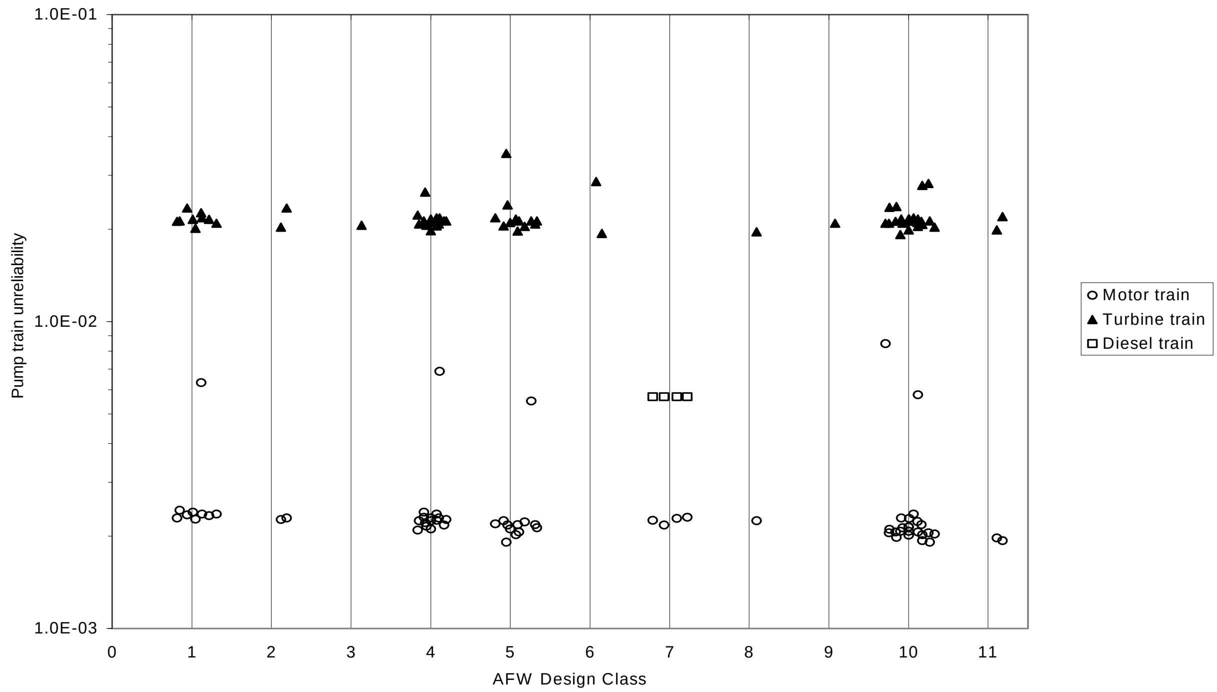


Figure 6. Plant-specific estimates of AFW system pump train operational unreliability grouped by design class.

Table 7. Average design class operational unreliability calculated from the 1987–1995 experience.

AFW Design Class	Number of Plants	Average[a] Design Class Operational Unreliability
1—(1M, 1T, 2SG)	9	6.7E-05
2—(1M, 2T, 2SG)	2	3.7E-06
3—(2T, 2SG)	1	5.4E-04
4—(2M, 1T, 2SG)	15	1.1E-05
5—(2M, 1T, 3SG)	12	3.3E-06
6—(3T, 3SG)	2	1.3E-04
7—(1M, 1D, 4SG)	4	1.8E-05
8—(1M, 1T, 4SG)	1	5.3E-05
9—(2T, 4SG)	1	6.2E-04
10—(2M, 1T, 4SG)	23	2.4E-06
11—(3M, 1T, 4SG)	2	2.6E-05
		overall average[a]—3.4E-05

a. The values are arithmetic averages.

CCF accounts for 72% to 99% of the unreliability in AFW designs consisting of three or more pump trains. CCF of the pumps (excluding the driver) failing to run or the feed control/injection segments are the leading contributors to AFW operational unreliability in design classes comprised of three or more diverse pump drivers. While the three turbine train configuration is most affected by CCF of the turbine steam supply (92%).

The Fussell-Vesely importance measures and rankings of the various failure modes are provided in Appendix D (see Tables D-9 and D-10).

3.2.5 Within Design Class Differences

The within design class differences shown in Figure 5 are attributed to the failure data and variations of AFW systems within a design class. Within design class differences due to system configuration are possible since the AFW design classes were categorized first by number of steam generators, then by number of pump trains, and finally by number of motor trains. Based on the analysis provided in Section D-2 of Appendix D, there are some differences that are attributed to AFW system design and modeling within a design class. These differences are discussed below.

Design Class 1 (1M, 1T, 2SG)—Three different system configurations are modeled in Design Class 1. The configurations are similar except for the modeling of the feed control segments. Two configurations have redundant feed injection paths per steam generator. However, the one configuration (Prairie Island 1 & 2) has the injection paths feeding into a common header that contains a motor-operated isolation valve prior to entering the steam generator. The other configuration (Arkansas Nuclear One 1 & 2, Palo Verde 1, 2, & 3, Crystal River) contains two redundant feed control segments per steam generator. The third configuration (only one plant; Fort Calhoun) has the pump trains discharge into a common header and only one injection path per steam generator. The common cause failure of the feed control segments for Fort Calhoun used an Alpha factor for the failure of 2-of-2 feed control segments while the other two configurations used a common cause failure of the feed control segments with an Alpha factor for the failure of 4-of-4 feed control segments.

The two highest AFW operational unreliabilities in this design class are Crystal River and then followed by Fort Calhoun. The AFW unreliability of Crystal River is mainly driven by the higher than average failure to start of the turbine and motor train probabilities. Fort Calhoun is driven by the modeling (failure of 2-of-2 feed control segments).

Design Class 4 (2M, 1T, 2SG)—Four distinct system configurations were fall within this design class. For one configuration (Kewaunee) the feed control segments are modeled as part of the pump train segment. The feed control was contained in the pump train since the pump/feed segment represented a series system of components. As a result, no common cause failure of the feed segments was modeled for this plant.

Two configurations [(St. Lucie 1 & 2, Ginna, Point Beach 1 & 2) and (San Onofre 2 & 3 and Waterford)] have redundant feed control segments per steam generator modeled. However, the San Onofre configuration have the injection paths feeding into a common header that contains a motor-operated isolation valve prior to entering the steam generator. The two configurations use an Alpha factor of failure of 4-of-4 feed control segments.

The fourth configuration of plants (Oconee 1, 2, & 3, Millstone 2, Three Mile Island) has a single feed control segment to each steam generator. The Alpha factor for this configuration is failure of 2-of-2 feed control segments.

Figure 5 depicts a wide range of variability amongst the AFW systems. The highest cluster of plants in Design Class 4 all belong to the fourth configuration of plants identified above. The high unreliability is mainly attributed to the CCF modeling of the feed control/injection segments, St. Lucie 2 had a higher than average feed control failure probability and turbine failure to start probability.

St. Lucie 2 follows the cluster of single feed control segment per steam generator plants. Although St. Lucie units have redundant feed control/injection paths, St. Lucie 2 had a higher than average turbine failure to start and feed control failure probabilities.

The next cluster of plants in Figure 5 are the San Onofre units and the Waterford plant. The AFW operational unreliability for this cluster is mainly attributed to the system differences noted above for the third configuration of plants.

Design Class 5 (2M, 1T, 3SG)—Two configuration exist within this design class related to the number of feed control segments. There were two different common cause feed control segments modeled for these configurations. They were 3-of-3 feed control segments (for the plants having only a single feed injection path per steam generator) and 6-of-6 feed control segments (for the plants having only a redundant feed injection paths per steam generator). An additional model difference is attributed to the success criteria. Farley 1 and 2 are the only plants in this class that use an AFW success criterion of 2-of-3 steam generators for success. The remaining plants in this design class use a success criterion of 1-of-3 steam generators. Farley 1 & 2 has 6 feed control segments (i.e., two per steam generator).

The two clusters of plants shown in Figure 5 for this design class are not based solely on the modeling differences noted above. The cluster representing the highest AFW operational unreliability within this design class consist of both 3-of-3 and 6-of-6 feed segment modeling. Beaver Valley 2 (the highest) and Robinson have six feed control paths while the North Anna units and Maine Yankee use three feed control paths. Beaver Valley 2 had a slightly higher than average turbine failure to start and feed control failure probability. Robinson had a high motor failure to start probability. North Anna units and Maine Yankee AFW unreliabilities are due to the 3-of-3 feed segment modeling.

Design Class 10 (2M, 1T, 4SG)—There is a slight difference in the system configurations in Design Class 10. The difference is attributed to the feed control segment associated with the motor-driven pumps. For the one configuration, the motor pump trains discharge into a common header. The other configuration has each pump train dedicated to a feed control segment which feeds the steam generators. This subtle difference will result in a slightly different system probability. All designs in this class utilize the same Alpha factor for the failure of 8-of-8 feed control segments.

As shown in Figure 5, six plants accounted for the variability in this design class. These six plants (in decreasing AFW unreliability) are Wolf Creek, Indian Point 3, Cook 1, Indian Point 2, Millstone 3, and Sequoyah 1. Wolf Creek demonstrated a higher than average feed control segment failure probability and a slightly higher than average turbine failure to start probability. Indian Point 2 and 3 had a higher than average motor failure to start and corresponding motor failure to start CCF probability. Cook 1 and Sequoyah 1 experienced a higher than average feed control segment failure probability. Millstone 3 had higher than average failure probability associated with the turbine maintenance out of service.

Design Class 11 (3M, 1T, 4SG)—There are only two plants in this design class. The two plants are South Texas 1 and 2 which are modeled the same. Although modeled the same, South Texas 1 had a higher than average feed control segment failure probability.

3.2.6 Unreliability Trends

Estimates of AFW unreliability on a per year basis were calculated to identify any overall trends within the industry estimates. Figure 7 displays the unreliability trend of the AFW system by calendar year. The unreliability for each calendar year was obtained using the constrained noninformative prior for each failure mode in the fault tree model shown in Figure 4 and pooled across plants for each calendar year as described in Appendix E. The unreliabilities were calculated for each reference plant, for each year. The results were combined into a weighted average and associated distribution for each year, with weights proportional to the number of plants in each class. There is no significant trend in the unreliability (P-value = 0.66).

To give some indication of the effect of plant age (i.e., older plants versus newer plants) on AFW performance, plant-specific estimates of AFW unreliability were plotted against the plant low-power license date. The plot is shown in Figure 8 with 90% uncertainty bars plotted vertically. A trend line and a 90% confidence band for the fitted trend line are also shown in the figure. There is no significant trend in the unreliability (P-value = 0.18).

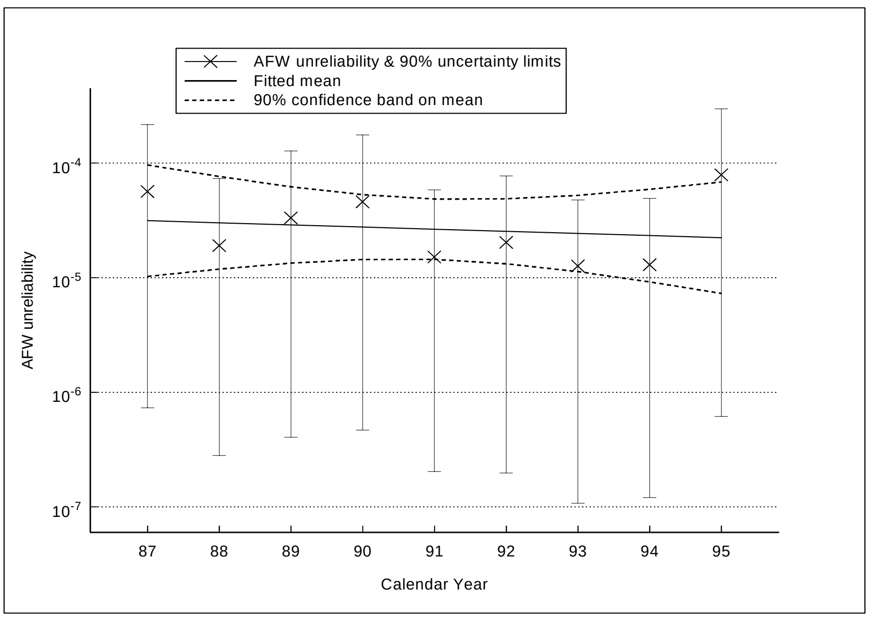


Figure 7. AFW system unreliability plotted by calendar year. The plotted trend is not statistically significant (P-value = 0.66).

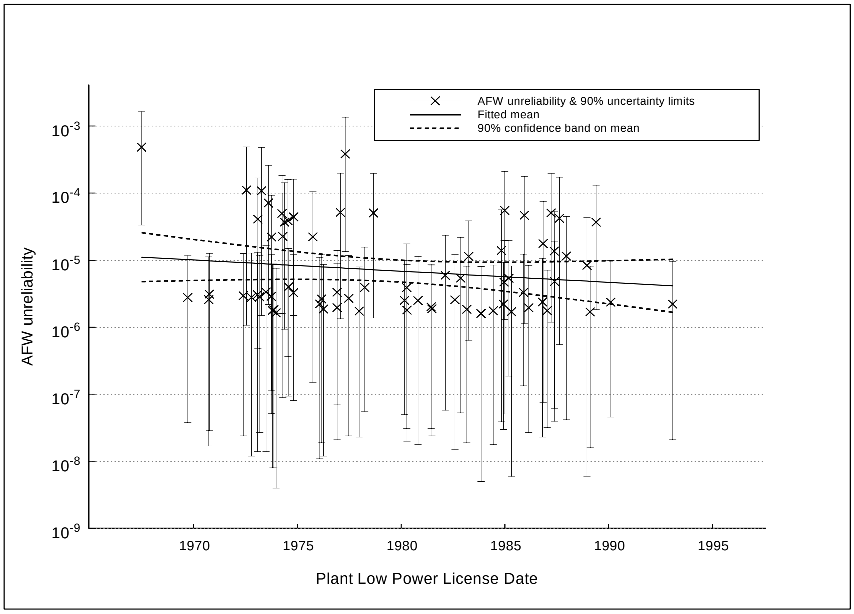


Figure 8. Plant-specific AFW system unreliability plotted by low-power license dates. The plotted trend is not statistically significant (P-value = 0.18).

3.3 Comparison with PRA/IPEs

The fault tree models for the 11 design classes shown in Figure 4 provided the logic template for generating 72 plant-specific AFW unreliability models. The plant-specific models were quantified based on success criteria and mission times stated in the PRA/IPEs. The logic model also provided the template for mapping relevant PRA/IPE component failure probabilities into an AFW system model. The mapping provides a relational structure for comparing PRA/IPE results to the estimates derived from the 1987–1995 experience.

To provide consistency in comparisons of PRA/IPE results to corresponding results of analysis of the 1987–1995 experience, the contributions to the AFW unreliability from support systems outside the AFW boundary defined in Section 2.1.3 were excluded from this study. (Section 3.5 provides a sensitivity analysis of the support system failures that lie outside the AFW system boundary on AFW unreliability.)

Recovery events were included in the unreliability analysis where such actions were found in the 1987–1995 experience. The recovery failure modes identified in the 1987–1995 experience are those events for which actual diagnosis and repair of AFW system are not required to make the system operational. PRA/IPEs may model this type of event at the system level. However, because of 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 that this type of recovery has on the final estimate (i.e., failure to recover from an automatic initiation 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 are required.

For comparison with PRA/IPEs, the failure probability estimates associated with the FTR mode of AFW operation were calculated on an hourly basis, rather than on a per demand basis as was done for the operational mission analysis of the previous section. An hourly failure rate was used to quantify the probability of failure to run. For these calculations, the run times stated in the LERs for the unplanned demands were used to estimate the hourly failure rate for the motor, turbine, and diesel-driven pump.

Long run times that are typically postulated in PRA/IPEs were infrequently observed in the 1987–1995 experience. The majority of the run times associated with the unplanned demands tended to be of much shorter duration. There were several instances of run times to approximately 24 hours for the motor trains. However, there were no failures associated with these events. The majority of the motor run times were less than 5 hours. For the turbine train, the longest run time event was about 8 hours, while the majority tended to be less than 2 hours. The diesel run times were generally less than 1 hour. The longest diesel run time is about 2 hours. (Histograms of the run times by driver type are provided in Figure E-2 of Appendix E.) 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 due to the majority of the run times were relatively short. Therefore, failure probabilities based on a FTR rate derived from short run times may not accurately reflect the longer mission time (24 hours) performance. Due to these concerns, the reader is cautioned in using the hourly rates without regard to the limited data used in the estimation.

The cumulative run time (actual plus extrapolated) based on the 1,987 unplanned demands for the motor-driven pump trains is approximately 4,618 hours. For the turbine-driven pump train, the cumulative run time (actual plus extrapolated) was 371 hours based on 583 unplanned demands. For the diesel-driven pump train, the 65 unplanned demands resulted in 42 cumulative hours of run time (actual plus extrapolated). Table D-1 in Section D-3 of Appendix D provides a summary of the run time estimation.

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

For the purposes of comparing the 1987–1995 experience and PRA/IPE data on a similar basis, the following conditions were assumed:

- A demand for AFW flow to a steam generator is received by the AFW system.
- The FTR contribution to the unreliability assumes a mission time stated in the PRA/IPE. These times are presented in Table 1.
- The AFW system success criterion is for transients that results in reactor trip and a loss of main feedwater and are based on those reported in the PRA/IPEs except where the success criterion uses a non-safety pump train. In these cases, the success criterion was modified to eliminate the non-safety pump train. The success criterion depicted in the logic models are presented in Table 1.
- Alternate suction sources are not modeled.

Besides the overall AFW 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 1987–1995 experience. The component failure modes identified in the PRA/IPEs were grouped according to the following breakdown:

Suction path segment (SUC)

FTO—Failure of the suction path valves and associated piping from the preferred water source (e.g., condensate storage tank) to deliver the flow to the pump trains necessary for AFW success.

Turbine steam supply (ST)

FTS—Failure to operate of the steam supply valves and associated piping upstream of the turbine steam stop valve.

Pump train segment (M or T or D)

FTS—AFW pump train failure to start, failure of the actuation circuit, and valve failures in the pump train suction and discharge piping.

FTR—Failure to run of the AFW pump train.

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

Feed control/injection header segment (INJ)

FTO—Failure of the steam generator injection paths/flow control valves and associated valves and piping to deliver the flow necessary for AFW success.

While there are additional component failure modes in a given PRA/IPE for the AFW 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 1987–1995 experience that were used in the PRA/IPE comparison calculations are listed in Table D-2 in Section D-4 of Appendix D. Plant-specific estimates were calculated using an empirical Bayes method since plant-to-plant variability was identified in several failure modes. Appendix E contains the results of the plant-specific analysis. For the failure modes where no plant-to-plant variability could be statistically identified (i.e., it is overwhelmed by the statistical data uncertainty), the industry average probabilities for the respective failure modes were applied to all plants.

3.3.2 Comparison with PRA/IPE Results

Figure 9 shows the PRA/IPE data results along with the model results using the 1987–1995 experience. Both the PRA/IPE and 1987–1995 experience estimates were calculated according to the mission times stated in the respective PRA/IPEs. The typical mission time postulated in the PRA/IPEs is 24 hours. However, there were several plants that used a mission time other than 24 hours [Farley (4 hours; Design Class 5), Seabrook (9 hours; Design Class 8), and Vogtle (5 hours; Design Class 10)].

The AFW system unreliability (i.e., mean) estimated using the PRA/IPE failure probabilities are generally lower than the estimates calculated from the 1987–1995 experience. The PRA/IPE estimates of

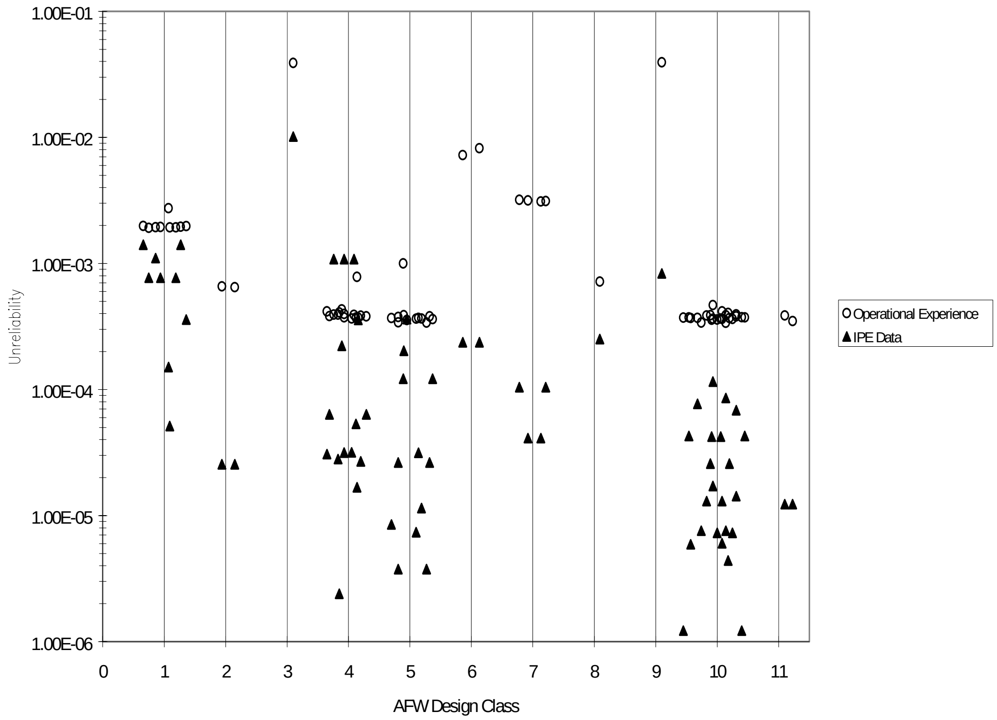


Figure 9. Plot of the PRA/IPE and 1987–1995 experience estimates of AFW unreliability for PRA/IPE comparison. Uncertainties are not plotted in order to provide better resolution of the plant-specific means. The uncertainties associated with the estimates are found in Tables D-6 and D-7 in Appendix D.

AFW unreliability range from 1.2E-06 to 1.0E-02. The plant-specific estimates of AFW unreliability based on the 1987–1995 experience range from 3.4E-04 to 4.0E-02.

To determine the reasons for the differences shown in Figure 9, the cut sets for the 11 reference plants (both IPE and 1987–1995 experience) generated for this study were compared with each other. (Table D-3 of Appendix D provides a summary listing of the cutset contribution for the eleven reference plants.) Two major areas were identified for the differences between the IPE results and this study's results.

First, the effect of the suction path (condensate supply) failure is significantly greater based on the 1987–1995 experience than IPE data. (The suction failure is an important contributor (as high as 99%) based on the 1987–1995 experience.) Generally, this event was not an important contributor in the PRA/IPEs due to modeling of only the passive components [tank rupture and passive piping component failures (e.g., normally or locked-open manual valves failing to remain open)] and/or the availability of additional suction sources. Based on the 1987–1995 experience, there were no failures of the passive components mentioned above. However, the failure identified for the PRA/IPE comparison resulted from a low suction pressure trip caused by insufficient water level. The water level problem resulted from a broken level indication. For this study, alternate sources were not included in the AFW models since not all plants have an alternate suction path. Further, for the plants that have an alternate suction source, no failure data for these alternate sources of suction water were available. Accounting for the alternate suction sources obviously lessens the significance of the suction segment in this report.

In the 1987–1995 experience, the one suction failure was recovered by automatic switchover to its alternate suction source. However, the quality of the alternate source of suction water degraded the operational performance of the AFW system. This recovered failure of the suction source led to the intrusion of foreign material (Asiatic clams) upon switchover to the alternate source of water (nuclear service water). The intrusion of clams and sludge into the AFW system caused flow blockage in different parts of the system. The quality of the alternate water source led to common cause failure of feed control valves (i.e., two of the four AFW injection paths to the steam generators were unable to deliver rated flow). NRC Information Notice (93-12) identified an additional problem with the alternate water sources. The Information Notice identified off-gassing in the AFW raw water sources that could cause air binding or damage to the AFW pumps. Generally, PRA/IPEs do not address these issues when evaluating the AFW suction source. Section 4.2.1.2 of this report discusses these issues in more detail.

The second area relates to plants with a turbine train; the failure to run probability of the turbine pump (based on the 1987–1995 experience) is greater than the probabilities stated in IPEs. Factors up to two orders of magnitude difference were observed. Similarly, the failure to run of the diesel is a major contributor for AFW systems utilizing a diesel-driven pump. The FTR-D probability calculated from the 1987–1995 experience is a factor of approximately 600 higher when compared to the IPE value. Although the differences in the IPE estimates and our estimates are significant, this study's results are based on sparse data, in particular, the run time hours. The turbine pump failure to run rate is based on three failures in 371 run hours while the diesel pump failure to run rate is based on one failure in 44 run hours. Since the run times are short and since the failures identified in the 1987–1995 experience generally occurred less than one hour after start, the evaluation of a time dependent failure rate was not possible. The failure rate based on this sparse data was assumed to be constant throughout the entire mission. (The constant failure rate assumption is assumed in the IPEs.). The difference in the results due to the FTR contribution requires additional data to resolve the discrepancy.

3.3.3 Pump Train Segment Unreliability Comparison

To better understand the importance of the individual pump trains, the pump train segment subtree for every plant was quantified using the 1987–1995 experience. Table 8 lists the average failure probability for each pump train segment for the IPE data and the 1987–1995 experience. The table also provides the range (minimum and maximum) of the mean failure probabilities. The motor, turbine, and diesel-driven pump train segment failure probabilities based on 1987–1995 experience are plotted in Figure 10. The corresponding IPE-based estimates are plotted in Figure 11.

The results in Table 8 indicate that the pump train segment average unreliabilities based on the 1987–1995 experience are higher, except for the motor-driven pumps, than the estimates based on the IPE data. To understand the reasons for these differences, the IPEs associated with the 11 reference plants were reviewed concerning pump train FTS and FTR data. While the FTS estimates reported in the IPEs

Table 8. Pump train segment failure probabilities calculated from IPE data and 1987–1995 experience.

	IPE Data		1987–1995 Experience	
Pump Train	Average[a]	Range	Average[a]	Range
Motor-driven	1.5E-02	2.8E-03—8.1E-02	7.4E-03	2.4E-03—1.4E-02
Turbine-driven	5.9E-02	7.0E-03—1.6E-01	1.9E-01	5.0E-02—2.0E-01
Diesel-driven	1.3E-02	6.6E-03—1.9E-02	3.6E-01	All plants had identical values

a. The values are arithmetic averages of the particular population of pump trains.

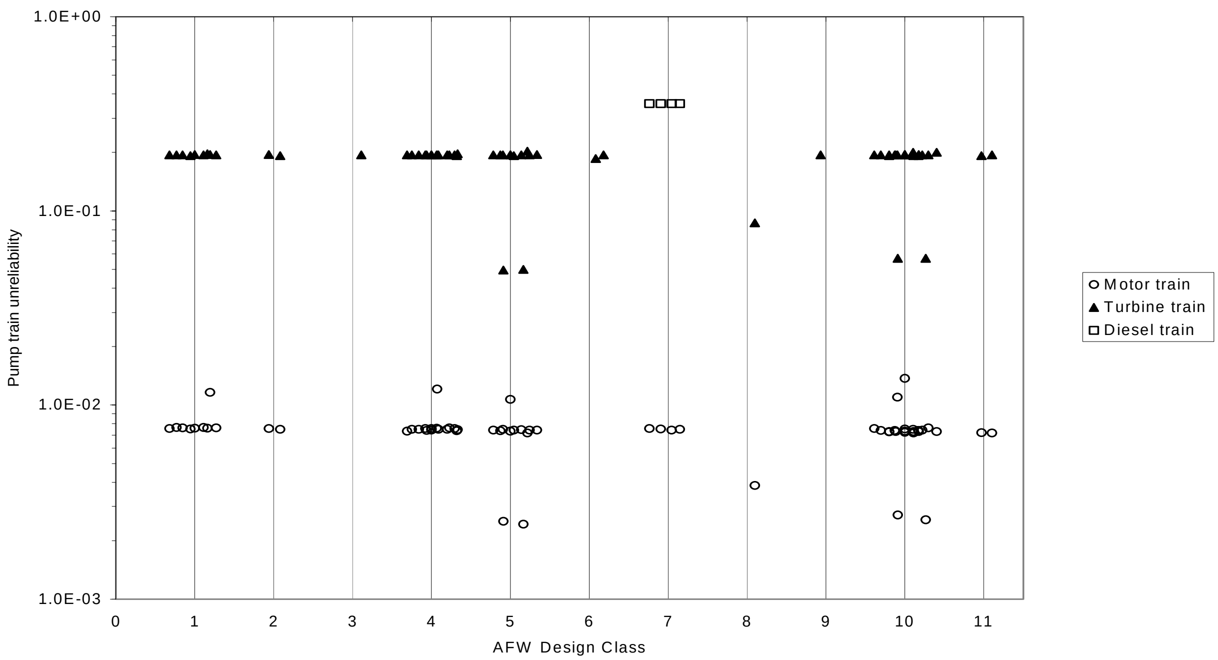


Figure 10. Plant-specific estimates (calculated from 1987–1995 experience) of AFW system pump train segment unreliability for comparison with PRA/IPE results grouped by design class.

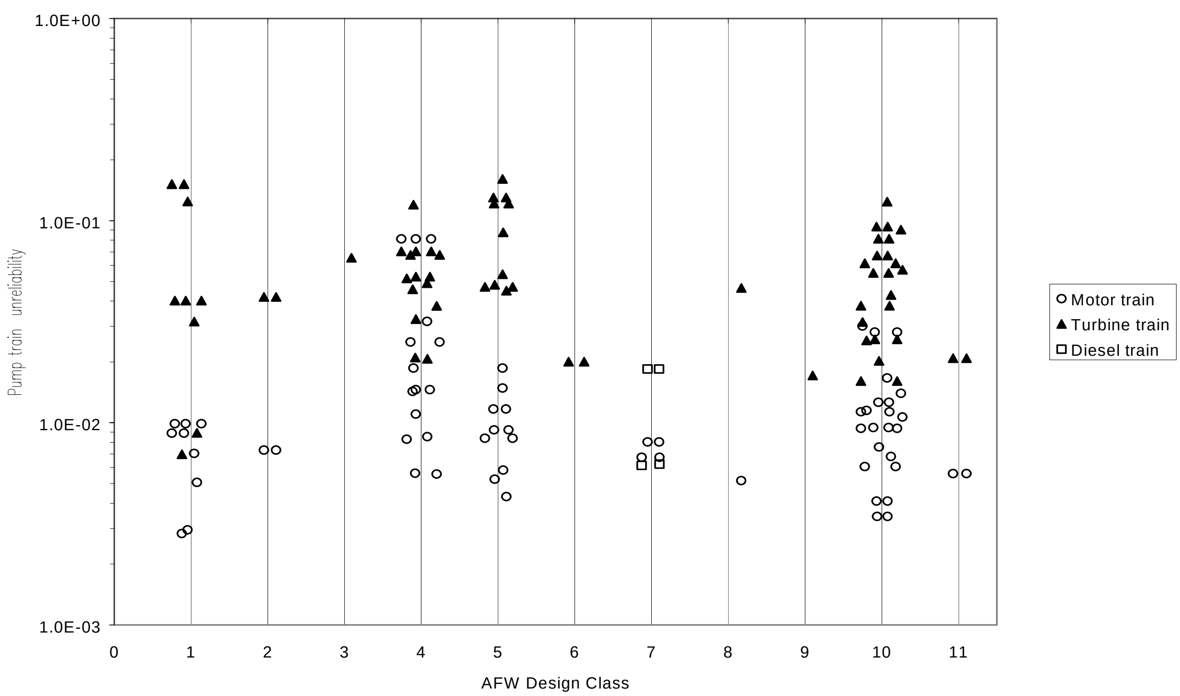


Figure 11. Plant-specific estimates (calculated from PRA/IPE information) of AFW system pump train segment unreliability grouped by design class.

for the 11 reference plants agree with the 1987–1995 experience estimates, the hourly rates tend to disagree for the motor and turbine-driven pumps estimates of FTR. The IPE estimates for failure to run are factors of 2 to 45 smaller for the motor-driven pump than the 1987–1995 experience estimates. For the turbine-driven pump, the estimates range from factors of 6 to 215 lower than the estimates based on 1987–1995 experience. Two FTR rates were generally reported in the IPEs for the reference plants; a generic rate (that was used a prior when Bayesian estimation was performed or for use when no plant data was available) and the final value used in the AFW quantification. The generic turbine FTR rates for the eleven reference plants varied by two orders of magnitude, 5E-05/hr to 1E-03/hr. As described later in Section 3.3.6, the range of turbine-driven pump FTR rates used in the IPEs (based on all 72 plants) is 2E-05 to 7.3E-03 per hour. The 2E-05 per hour failure rate appears extremely optimistic in light of the 1987–1995 experience used in this study. The IPE reporting this failure rate indicated insufficient failure data [one turbine failure in 60 hours of operation (1.7E-02 hourly failure rate) covering 5 years of plant commercial operation] to use a estimate based only on plant-specific data, so instead, the generic value (2E-05/hr) was used. The use of a generic estimate that is three orders of magnitude lower does not seem reasonable based on the plant's raw failure data and in light of the 1987–1995 experience.

Based on the review of the reference plants, the FTR rates for the turbine pump used in the IPEs for the final quantification of the AFW models are less than the turbine pump FTR rates calculated from the 1987–1995 experience. Generally, in the cases where Bayesian updating was performed in the IPE, the plant-specific data had little influence on the mean of the prior distribution. Based on the review of the IPEs there was insufficient plant data to influence the prior. For the IPEs that reported plant-specific failure data of the AFW system, classical estimates calculated from these data tend to support the values estimated from the 1987–1995 experience. That is, the plant-specific raw failure data do not support the highly optimistic generic failure rates being used in some of the IPEs. Table D-4 of Appendix D provides a tabulation of the data review.

3.3.4 Failure to Start—Pump Train Segment

Table 9 provides a summary of the pump train segments failure to start found in the PRA/IPEs and the estimates calculated from the 1987–1995 experience. The average of the PRA/IPE estimates of FTS-M is about a factor of three larger than the mean probability calculated from the 1987–1995 experience. (The extremely small value calculated for the lower 5% bound associated with 1987–1995 experience is due to the plant-to-plant variability of the FTS-M data.) For the turbine-driven pumps, the average of the FTS-T estimates for the PRA/IPEs and the estimate calculated from the 1987–1995 experience are similar. The diesel-driven pumps differed by a factor of less than based on the average of the FTS-D estimates for the PRA/IPEs and the 1987–1995 experience mean. The causes of the failure to start events are described in Section 4.2.

Table 9. Pump train segment failure to start probabilities (per demand) calculated for comparisons with PRA/IPE results and 1987–1995 experience.

	IPE Data		1987–1995 Experience	
Failure to Start	Average	Range	Mean	90% Uncertainty Interval
Motor-driven	2.8E-03	2.8E-04—1.6E-02	8.1E-04	<1E-08—4.7E-03
Turbine-driven	1.7E-02	1.0E-03— 4.6E-02	1.4E-02	4.9E-03—2.6E-02
Diesel-driven	3.9E-03	2.6E-03—5.1E-03	5.7E-03	9.5E-06—2.3E-02

3.3.5 Failure to Run—Pump Train Segment

Table 10 is a summary of the failure to run estimates found in the PRA/IPEs and the estimates calculated from the 1987–1995 experience. Generally, FTR estimates were different for the turbine and diesel-driven pumps for the reasons noted earlier.

The average of the PRA/IPE estimates for the motor-driven pump failure to run agrees with the mean estimate calculated from the 1987–1995 experience. However, the range of the plant-specific estimates calculated from the PRA/IPE information is about three orders of magnitude. Three PRA/IPE estimates lie above the upper 95% bound, while four lie below the lower 5% bound of the 1987–1995 experience estimate FTR-M.

The average of the PRA/IPE estimates for the turbine-driven pump failure to run is about a factor of five lower than the mean estimate calculated from the 1987–1995 experience, 1.7E-03/hr versus 8.2E-03/hr, respectively. The FTR-T estimates for 50 of the 68 plant estimates (four plants don't have turbines) lie below the lower 5% bound of the 1987–1995 experience estimate of FTR-T.

Only four plants (Design Class 7) use a diesel-driven pump that is safety-related. The estimates of AFW diesel-driven pump failure to run probability as reported in the PRA/IPEs is 8.0E-04 per demand. No hourly rate was calculated in the PRA/IPE. Further review of the cited reference (NUREG-4550) indicates this value is in units of failures per hour (i.e., 8.0E-04 per hour). The estimate for AFW diesel-driven pump train failure rate calculated from the 1987–1995 experience is 2.7E-02/hr. The 1987–1995 experience estimate is about a factor of 30 greater than the NUREG-4550 estimate. The reader is cautioned that the 1987–1995 experience result of 2.7E-02 per hour is based on one failure in 44 operating hours. Since the diesel pump run time is small, additional 1987–1995 experience may lead to better agreement between the two estimates.

The causes of the failure to run events are described in Section 4.2.

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

Table 11 is a summary of the maintenance-out-of-service estimates found in the PRA/IPEs and the estimates calculated from the 1987–1995 experience. A description of the maintenance failures is provided in Section 4.2. In this study, maintenance unavailability is estimated using the failures and demands when the AFW system was required to supply water into the steam generator (i.e., a reliability parameter). Risk analysis generally accounts for the maintenance-out-of-service probability as an unavailability estimate (i.e., fraction of AFW 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 1987–1995 experience probability estimates of maintenance-out-of-service.

Table 10. Pump train segment failure to run probabilities calculated from IPE data and 1987–1995 experience.

	IPE Data		1987–1995 Experience	
Failure to Run	Average	Range	Mean	90% Uncertainty Interval
Motor-driven	2.2E-04/hr	5.3E-06—3.0E-03	2.4E-04/hr	1.8E-05—6.9E-04
Turbine-driven	1.7E-03/hr	2.0E-05—7.3E-03	8.2E-03/hr	2.3E-03—1.7E-02
Diesel-driven	8.0E-04/d	All used 8.0E-04/d	2.7E-02/hr	2.0E-03—7.5E-02

Table 11. Pump train segment maintenance-out-of-service probabilities (per demand) calculated from IPE data and 1987–1995 experience.

	IPE Data		1987–1995 Experience	
Maintenance-Out-of-Service	Average	Range	Mean	90% Uncertainty Interval
Motor-driven	4.8E-03	4.8E-06—2.3E-02	1.1E-03	2.4E-04—2.5E-03
Turbine-driven	7.1E-03	2.4E-06—3.5E-02	4.6E-03	1.7E-05—1.8E-02
Diesel-driven	7.7E-03	3.0E-03—1.2E-02	N/A	N/A

For MOOS-M, the average of the PRA/IPE estimates is about a factor of four greater than the mean estimate of the 1987–1995 experience. Both the PRA/IPE estimates and 1987–1995 experience estimates for MOOS-T compare well. No estimates of MOOS-D were calculated since there were no observed failures and too few demands to make a meaningful estimate for this failure mode. Therefore, MOOS-D was not included in the AFW unreliability analysis using the 1987–1995 experience.

3.3.7 Failure to Operate—Feed Control/Injection Segment

Generally, the PRA/IPE and 1987–1995 experience estimates agreed for this failure mode. The FTO-INJ failure mode is a relatively insignificant contributor (1%) to AFW unreliability due to levels of redundancy of the segments and small failure probabilities associated with this failure mode. No dominant cause is identified for this failure mode. Section 4.2 provides further details of the causes.

3.3.8 Failure to Operate—Suction Segment

Generally, the PRA/IPE and 1987–1995 experience estimates differed for this as noted earlier in Section 3.3.2. This failure was important in AFW configurations comprised of three or more diverse trains because this single failure mode compromises the multiple levels of redundancy. The suction path was the least important in two turbine trains (less than 1%) and three turbine trains (5%) because the independent failure to run rate for turbines was relatively higher than the suction failure probability.

3.3.9 Common Cause Failure

Due to the summary nature of the PRA/IPEs, no meaningful comparisons of CCF could be made. Based on the 1987–1995 experience, the CCF of the pumps failing to run is the leading CCF contributor. This event represents only the pump end and is independent of the pump driver. The pump failures were attributed to disintegrating channel ring vane assemblies. Further details of this failure mode are provided in Section 4.2.

CCF of the feed control/injection segments (DIS-SEG) is not an important contributor (less than 1%). There were four events involving CCF failures of the flow control valves. Intrusion of clams and human error are several reasons for these CCFs. Section 4.2 describes these failures in more detail.

CCF of the steam supply to the turbine train (TD-QT-STM) is not an important contributor (less than 1%).

3.4 Human Error of Commission

There were four events identified where one or more trains of AFW were made unavailable by actions of the control room operators. The operators secured AFW trains in an attempt to protect the reactor from overcooling or to preclude AFW pump runout. In three events, the control room operators rendered a single train of AFW unavailable. These train level events were categorized as either failure to start or run and were included in the train segment quantification.

However, in one event, the entire system (three operating trains were secured while running) was made inoperable while a valid low steam generator water level signal existed. This event occurred when an operator placed the pump switches in pull to lock to control reactor cooldown while main feedwater was available. Although this event is significant from a regulatory perspective (i.e., operator securing a safety system while a valid AFW actuation signal existed), other plant conditions warranted not classifying this event as a system failure. Section 4.2.1.1 of this report describes this EOC as well as other human errors in more detail.

PRAs generally do not include EOCs. If modeled in PRAs, generally these types of events would be analyzed and quantified at the accident scenario level and not at the system level, such as this analysis. Issues regarding the best course of action to terminate the accident scenario would be factored into the evaluation. EOCs of the type described would be quantified conditional on the plant state during the accident scenario.

This particular EOC was omitted from the AFW unreliability calculations since there was no loss of main feedwater during this event. However, to better asses the sensitivity of AFW unreliability to this type of event, a separate analysis of the AFW system was performed with the system EOC included. For the AFW system, there was one failure identified during the 1,117 system demands that resulted in the operation of the AFW system being terminated inadvertently. (Note, there is one more demand than the number of suction demands identified in Table 2. This is due to an event where the AFW pumps were already running prior to the loss of main feedwater. Since a portion of AFW system was operating, no demand on the suction segment resulted from the unplanned demand.) Since the system failure was recovered, the failure probability estimate and associated uncertainty of EOC are (1.6E-04, 1.3E-03, 3.5E-03). The EOC estimate with recovery included is (5.5E-07, 3.4E-04, 1.4E-03). The arithmetic average of the 72 plant-specific AFW unreliabilities with this EOC is 2.4E-03. AFW unreliability with EOC represents about a 15% increase in the average AFW unreliability without EOC (2.1E-03). Within certain design classes, the effect on the AFW unreliability of an EOC affecting the entire system is more pronounced due to the compromising of multiple redundant trains.

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

The analysis of AFW unreliability does not include failures from support systems that lie outside the AFW system boundaries defined for this study (see Section 2.1.3). However, to understand the effects of those support system failures (outside the AFW system boundary) on the AFW unreliability estimates, simple estimates of system level and pump train unreliability were calculated with support system failures included.

Based on the 1987–1995 unplanned demand data, five LER events involving six failures were attributed to support system failures that are outside the AFW system boundary defined for this report. None of these support system failures were found that disabled the entire AFW system. The failures were all related to the motor-driven AFW pump failing to start automatically. Generally, these auto-start failures were due to testing of the solid-state protection system. The auto-start failures were all recovered by manually starting the affected motor-driven pump. The effects of including these support system failures on the FTS-M estimates are negligible. The base FTS-M (estimate that does not factor in recovery) would increase by a factor of two. The final unrecovered estimate of FTS-M would essentially remain the same. This effect is due to the fact that all the support system failures were recovered.

3.6 Standard Review Plan, Station Blackout, and ATWS

The risk importance of the AFW system operation in response to certain initiators was identified in early risk assessments. In order to reduce the risk significance of these events, regulatory analyses were performed and rulemaking with regard to AFW design has been implemented. Estimates of AFW unreliability have been used in the acceptance criteria of AFW design adequacy and risk issues associated with station blackout and anticipated transients without scram (ATWS). Several estimates from these past studies are compared to the results of this study. The following sections provides a summary of the comparisons.

3.6.1 Standard Review Plan—Comparison to NUREG-0800

The Standard Review Plan (NUREG-0800)[52] for the Auxiliary Feedwater System provides acceptance criteria for the AFW general design. Further, it states that the recommendations of NUREG-0611[53] and 0635[54] shall be met. Part of these recommendations specify that an acceptable range of AFW system unreliability should be 1E-04 to 1E-05 per demand calculated by the methods and data identified in NUREG-0611 and NUREG-0635. The NUREG-0611 and 0635 methodology used a simplified fault tree to estimate the AFW unreliability on demand of the AFW system. The NUREG-0611 and 0635 data consisted of hardware and human error considered to be applicable to all the AFW system designs. The objective of the unreliability analysis (NUREG-0611 and 0635 evaluation) was to determine the variability in the AFW reliability due to system design differences and not to show the effect of plant-specific variability in the data. However, the analysis used for this report incorporates the variability in the data (i.e., plant-specific data relevant to the AFW system) and in the AFW system designs (11 design classes). The plant-specific estimates (based on the operational unreliability calculated from the 1987–1995 experience) range from 1.5E-06 to 6.2E-04 per demand. Five out of the seventy-two estimates are greater than the 1E-04 per demand recommended in the Standard Review Plan when accounting for variability in the data. The designs at four of these five plants consist of turbine trains only. In addition, two of these four plants have additional means to provide feedwater to the steam generators. Factoring in these alternate means to provide additional AFW capability lowers the unreliability for these designs to the less than 1E-04. The Standard Review Plan does allow for AFW systems not meeting the recommended unreliability to consider other compensatory factors. For example, alternate methods for accomplishing the AFW safety function or other reliable means to cool the reactor core following abnormal events may be considered. This study is not structured to account for the compensatory factors.

3.6.2 Station Blackout—Comparison to NUREG-1032

The reliability of decay heat removal systems that are not dependent on ac power is important in mitigating the effects of a station blackout. Generally for PWRs, the decay removal function is provided by the turbine train(s) of AFW. NUREG-1032[55] assessed the likelihood of core damage resulting from station blackout by the probability of station blackout combined with the failure probability to maintain adequate core cooling by ac independent systems. One of the dominant accident sequences was station blackout followed by early (initial) AFW failure and failure to recover ac power within 1/2 to 1 hour.

NUREG-1032 obtained the estimates of probability for initial AFW turbine train failure from NUREG/CR-3226.[56] The estimate for a single turbine train was estimated at 0.04. For a two turbine train configuration, the failure probability stated in NUREG-1032 is 0.002. The turbine failure probabilities used by NUREG/CR-3226 are shown in Table 12. The NUREG-1032 estimates for the turbine train failure are slightly more pessimistic than the estimates computed from the 1987–1995 experience.

3.6.3 ATWS—Comparison to SECY-83-293

In 1980, after the evaluation of information gathered over the preceding 10 years, the NRC reported the frequency of a severe ATWS may be unacceptably high. Following the issuance of this evaluation, several rules requiring improvements in reactor design to reduce the risk from ATWS were proposed. The proposed rules were evaluated by the NRC staff through the use of PRA techniques, engineering judgment, and value/impact analyses to determine cost-effective ways to reduce the risk of ATWS events. SECY-83-293 (Rulemaking Issue, Affirmation)[57] was issued to seek approval for publication of a final rule on the ATWS issue. SECY-83-293 identified early actuation of AFW as a way to limit the reactor system pressure during most ATWS events in PWRs. The AFW unreliability used in the value/impact analyses for the Westinghouse plants was 1.0E-03. This value was based on needing one train of AFW. For Combustion Engineering and Babcock & Wilcox designs, the AFW unreliability used was 4.0E-02 This value is based on 2 of 2 AFW trains for ATWS events.

The reliability analysis of the Westinghouse plants in this study generally used a one train success criterion for AFW. Therefore, the arithmetic average of the Westinghouse plants AFW unreliability was considered appropriate for comparison to the ATWS value cited in SECY-83-293. The Westinghouse average unreliability calculated from the PRA-based mission unreliabilities and based on the 1987–1995 experience is 1.7E-03. This value is comparable to that assumed in the analysis supporting the ATWS rulemaking. Although some of the Westinghouse plants estimates are high based on the 1987–1995 experience, SECY-83-293 cited that the likelihood of ATWS is insensitive to AFW unavailability. (For the other designs, no AFW unreliability sensitivities were done since the fraction of time for unfavorable moderator temperature coefficient was a key issue.)

Table 12. A comparison of the turbine train estimates used in NUREG/CR-3226 to the turbine train unrecovered failure probability estimates computed from the 1987–1995 experience.

Event Name	NUREG/CR-3226	1987–1995 Experience (Unrecovered estimate)
Turbine-FTS	2.0E-02	1.5E-02[a]
Maintenance-out-of-service	2.0E-02	4.6E-03
Common mode	1.0E-04	2.1E-03[b]
Single turbine train failure[c]	4.0E-02	2.0E-02
Two turbine train failure[d]	2.0E-03	2.3E-03

a. Includes FTS of turbine (1.4E-2) and steam supply (1.0E-3).

b. Common mode includes 2 of 2 turbines fail to start [Alpha (6.8E-02) × Turbine FTS Q_t (2.9E-02)] and failure of steam supply [Alpha (8.5E-2) × Steam supply Q_t (1.4E-03)].

c. Unreliability = (turbine-FTS) + (maintenance-out-of-service).

d. Unreliability = $(\text{single train})^2$ + (common mode).

Table 13 provides the turbine and pump train unreliability for the two train Combustion Engineering and Babcock & Wilcox plants. Assuming a motor and turbine train configuration and two-train success criterion, the unreliability estimate for the Combustion Engineering and Babcock & Wilcox plants is 2.5E-02. This value is in fairly good agreement with the estimate stated in SECY-83-293. The contributions of CCF and other independent failures were insignificant since failure of either train would produce the undesired outcome.

Table 13. Motor and turbine train failure estimates used for making comparisons of AFW unreliability of Combustion Engineering and Babcock & Wilcox plants to the estimate used in SECY-83-293.

Pump Train	FTS[b]	FTR[b]	MOOS[b]	Train Unreliability
Motor	8.1E-04	5.7E-04	1.1E-03	2.5E-03
Turbine	1.5E-02[a]	3.6E-03	4.6E-03	2.3E-02
			Motor or turbine fails[c]	2.5E-02

a. Includes FTS of turbine (1.4E-02) and steam supply (1.0E-03).

b. Since prompt AFW actuation is required for successful ATWS mitigation and long term capability of AFW to run, the estimates provided are based on the operational estimates provided in Table 4.

c. The estimate does not include CCF. The effect of not including CCF contributions is negligible due to its relatively small size compared to the independent train failure probabilities.

4. ENGINEERING ANALYSIS OF THE 1987–1995 EXPERIENCE

This section documents the results of an engineering evaluation of the 1987–1995 operational experience of the AFW system obtained from LER data. The objective here is to analyze the data and provide insights into the performance of the AFW system throughout the industry, and at a design class and plant-specific level. Because of the LER reporting requirements, discussed previously in Section 2.2, only the segment failures that occurred during unplanned demands were used to develop trends and failure frequencies. The failures found during surveillance tests and other routine plant operations are discussed only in qualitative terms. The following paragraphs summarize the major findings in this section of the report.

- Analyses of trends in the failures and unplanned demands throughout the industry indicated statistically significant trends for, unplanned demands by calendar year, feed segment failures by calendar year, unplanned demands versus low-power license date, and motor-driven pump segment failures versus low-power license date. No other trend analysis indicated a statistically significant trend.

- The AFW segment failures were reviewed to determine the factors affecting overall system reliability. The review indicated that there were 78 AFW segment failures during the 1,117 system demands observed from 1987 through 1995. None of these failures resulted in complete system failure, at least one train was fully operable and providing adequate flow to the steam generator(s) for decay heat removal. Included in these 78 failures, were several instances where multiple independent trains did not function as designed. These cases were attributed to either common cause failures, a loss of the normal suction source, or an error of commission. Actual recovery from segment failures or failures judged to be recoverable, were observed in approximately half of the observed failures. Segment failures attributed to personnel error were in most cases readily recovered. Segment failures attributed to hardware, design, and other categories were recovered in approximately half of the observed events. Segment failures attributed to pre-existing maintenance errors and the environment were normally not recovered or readily recoverable.

- Common cause failure was a leading contributor to AFW unreliability as indicated previously in Section 3. The events that influenced the CCF contribution to AFW unreliability were four events involving failures of the feed control segments to operate, two events involving the motor-driven pump segments, and one event involving both the motor- and turbine-driven pump segments. The common cause failures associated with the motor-driven pump segments were both failures to start. The common cause failure that affected both the motor- and turbine-driven pump segments was classified as a failure to run. These common cause failures were caused by three hardware-related problems, two pre-existing maintenance errors, a design error, and an environmental problem. Three of the seven failures were recovered or judged to be recoverable (two of the hardware-related failures and a pre-existing maintenance error).

- The failure associated with the suction segment occurred during an automatic start of two motor-driven pumps. Suction pressure was insufficient for pump operation, which caused an automatic shift to the assured source (service water). The low suction pressure condition was a result of operating with the AFW condensate storage tank isolated and not maintaining adequate level in the upper surge tank, which provides an alternate source of feedwater to AFW. The AFW condensate storage tank had been isolated due to leakage. At the time of the AFW demand, the upper surge tank was thought to be 95% full. However, the chart recorder used for level indication was later discovered to have been broken and indicating a false trace at 95%. The actual level of the upper surge tank was approximately 65%. Even though AFW pump suction shifted to the assured source (service water), the service water system was fouled with clams and sludge which caused the AFW flow control valves to the steam generators to clog significantly reducing flow to two of four steam generators.

- In addition to the suction segment failure that occurred during an unplanned demand, there were two other events in which the backup source of water would not have functioned if needed for long-term AFW operation. These two failures, while not contributing to the unreliability estimate provided in Section 3 (because the demand counts could not be reasonably estimated), do provide additional insights into the importance of the backup water supply to the AFW system. One of these two failures occurred as a result of clam and sludge intrusion into the backup suction supply source (different event from the one mentioned in the previous paragraph). The other suction segment failure was the result of air formation in the suction piping caused by off-gassing. In addition, undersized piping was also found when a simultaneous startup of multiple pumps caused oscillations of pump suction pressure, resulting in multiple pump trips on low suction pressure, despite the existence of adequate static net positive suction pressure.

- In the 1985-1997 experience there was one event in which all three trains of AFW were intentionally disabled by operator action when the system was required to be in operation by plant technical specifications. Specifically, following a reactor trip, with all the AFW pumps running as a result of multiple low-low steam generator levels, the pumps were placed in “pull-to-lock,” and the steam supply valves to the turbine-driven pump were closed. An operator performed the action in an effort to limit a normal post-trip cooldown without informing or obtaining permission from the control room supervisor. While the electric main feedwater pumps were running, the feedwater isolation valves were closed which is normal following a reactor trip and turbine trip. The procedure required AFW flow to be throttled to 400 gpm if the cooldown continued below the no-load T_{ave} value.

- In addition to the event where all AFW trains were disabled by operator action, there were three other events in which operator action rendered at least one train inoperable when it was needed to restore or maintain steam generator levels. These instances were the result of (1) being unable to control steam generator levels, (2) the shutdown of an operating pump when no other method was available to feed the steam generator, and (3) opening system cross-connect valves, thereby causing two trains of AFW flow to be discharged to a test line when flow was needed to restore steam generator level.

- The distribution of the 78 segment failures showed that there were 32 feed control segment failures, 19 motor-driven pump segment failures, 21 turbine-driven pump segment failures, and 6 failures comprising diesel-driven pump (2), instrumentation (2), suction supply (1) and turbine steam supply (1). Of these 78 segment failures, six were attributed to problems with support systems.

    - The feed control segment failures were primarily caused by hardware malfunctions, 56%. Personnel error in the operation of the system, and failure to restore the segment to an operable status after maintenance contributed to about 30% of the failures. Approximately half of the feed control segment failures were recovered or judged to be easily recoverable. Most of the failures that were attributed to a hardware related problem were recovered. With the exception of one personnel-error related failure, none of the other failures from other causes were recovered or judged to be recoverable.

- Of the motor-driven pump segment failures during unplanned demands, five were classified as failures to run and 14 as failures to start. For the failures classified as failures to run, no one cause category dominated the failures. Recovery of the failures to run was only observed for the two failures associated with the error of commission (personnel error). For failures to start, maintenance errors accounted for 50% of the failures contributing to the unreliability estimate. Eleven of the failures to start were recovered or judged to be recoverable. A common cause failure of two pumps and an independent failure, both as a result of preexisting maintenance related errors, constituted the non-recovered failures.

- Of the of turbine-driven pump segment failures during unplanned demands, four were classified as failures to run and 17 as failures to start. Approximately 50% of the failures were hardware related. No other cause category contributed to a significant percentage of failures. With the exception of the three personnel-error-related failures, 17 of 18 remaining failures resulted in turbine overspeed trips. These trips were caused by worn, loose, or mis-aligned trip linkages, water accumulation in the steam supply lines, and contaminated governor hydraulic oil. These overspeed trips were primarily mechanical overspeed trips that could not be reset in the control room. As a result, only approximately half of the overspeed trips were recovered or judged to be recoverable.

- While failures attributed to design-related problems were a relatively small contributor to the total number of failures (5 of 78), they are important in that the failures occurred when the system was being operated differently during an unplanned demand than how it is normally tested. Failures related to pre-existing maintenance errors could also be considered a small contributor to the total number of failures (10 of 78); however, they are important because they indicate that the post-maintenance tests are not ensuring that the segment is fully operable after maintenance. In one instance, the pre-existing maintenance error went undetected for over a year. Moreover, only one failure related to pre-existing maintenance was recovered.

- In addition to the above findings, the contribution to segment failures as a result of support system failures were relatively small. Only 6 of 78 failures observed during unplanned demands could be attributed to support system failures. Of these six failures, all were recovered by operators manually starting the affected segment. The failures were primarily the result of the solid state protection system being in test at the time of the demand, which prevented an automatic start of the pumps.

Sections 4.1 through 4.3 provide a detailed summary of the industry data supporting the above results as well as additional insights 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, (2) identification of the factors affecting segment reliability in the industry, and (3) identification of the factors affecting segment reliability for each design class.

4.1 Industry Trends

This section provides the results of industry trend analyses. The analyses include AFW unplanned demands and segment failures plotted against calendar year and low-power license date. The frequencies of unplanned demands or failures provided in the figures is the number of events (unplanned demands or failures) that occurred in the specific year divided by the total number of plant operational years for the specific year. Plant operational years was estimated as described in Section A-2.2.4 of Appendix A. The frequencies and 90% Bayesian intervals are plotted in each figure in this section. A fitted trend line, and 90% confidence band on the fitted line, is also shown in the figures. Because of the reporting requirements associated with AFW, only the segment failures that occurred during unplanned demands were used to develop the associated failure frequencies.

4.1.1 Trends by Year

Table 14 provides the AFW segment failures and unplanned demands that occurred in the industry for each year of the study period. Failures classified as maintenance out of service events (used in Section 3 for the unreliability analysis) and failure of support systems were excluded from Table 14.

4.1.1.1 Unplanned Demands. Figure 12 is an illustration of the AFW system unplanned demand frequency for each year of the study. Figure 13 is provided for informational purposes, and provides the PWR reactor trip frequency for each year of the study period. The figures include fitted trend lines and 90% confidence bands for the fitted trends. The frequency is the number of events (unplanned demands or reactor trips) that occurred in the specific year divided by the total number of plant operational years for the specific year.

Table 14. Number of AFW events by category for each year[a] of the study.

Category	1987	1988	1989	1990	1991	1992	1993	1994	1995	Total
System demands	221	160	145	132	116	123	71	71	78	1,117
Motor-driven pump										
Failures	3	3	3	1	1	2	2	0	0	15
Demands	390	274	269	243	204	219	126	124	146	1,995
Turbine-driven pump										
Failures	6	2	5	2	2	1	1	0	2	21
Demands	116	74	89	65	64	63	43	46	42	602
Feed control										
Failures	8	7	6	3	2	2	2	0	2	32
Demands	1,009	775	662	644	526	595	328	314	372	5,225
Plant operating years[b]	46.73	51.70	51.27	53.56	57.21	58.05	57.12	60.09	60.21	496

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

b. Plant operating years excludes shutdowns that are greater than two calendar days in length.

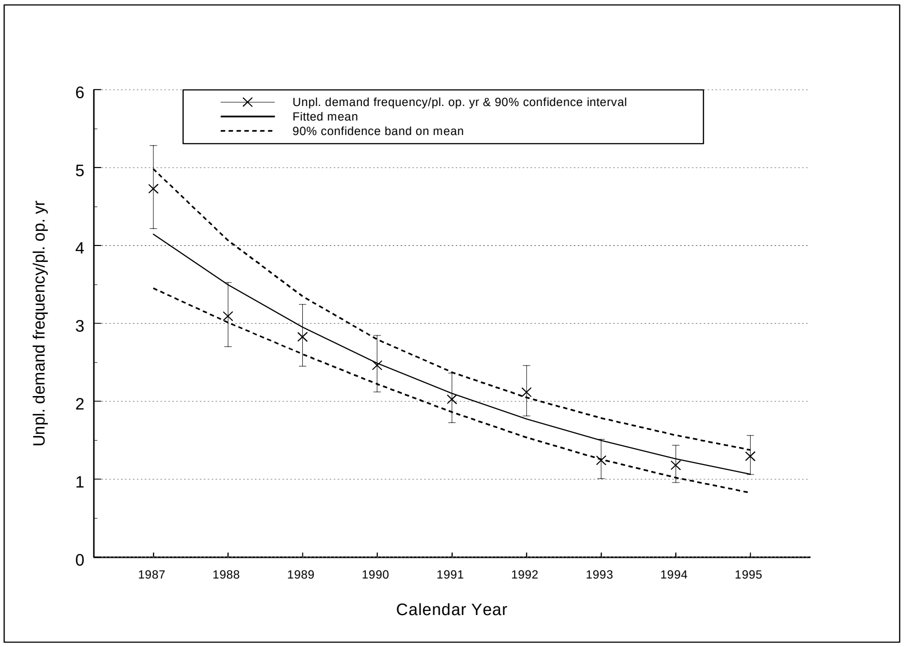


Figure 12. Unplanned demands trended by calendar year, with confidence limits on the individual frequencies. The decreasing trend is highly statistically significant (P-value <5E-5).

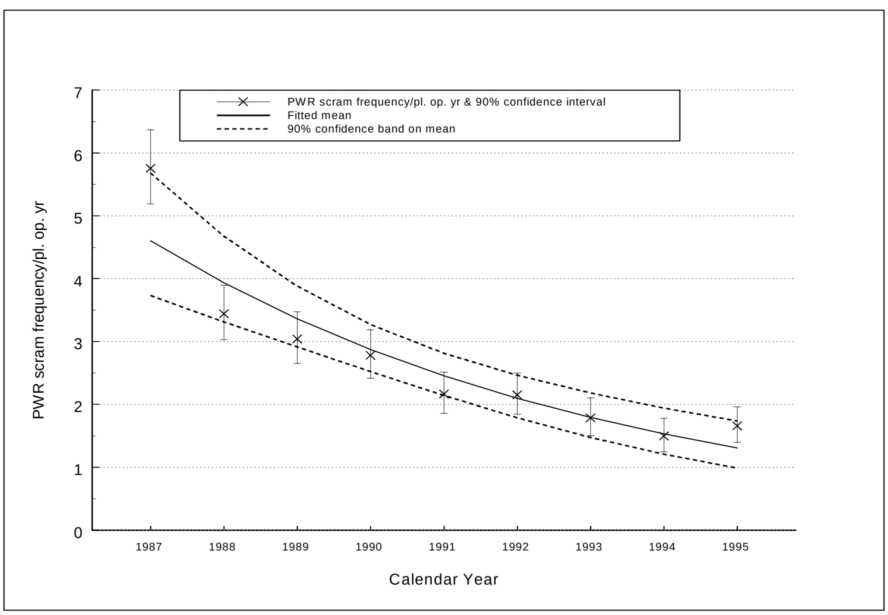


Figure 13. PWR scram frequency trended by calendar year, with confidence limits on the individual frequencies. The decreasing trend is highly statistically significant (P-value <5E-5).

As shown in Figure 12, the frequency of unplanned demands per plant operating year decreased from approximately 4.75 in 1987 to approximately 1.75 in 1995. Analysis of the system unplanned demand frequency for a trend showed a statistically significant trend over the study period. The P-values of the fitted trend line is <5E-5. Figure 13, which shows the PWR reactor trip frequency over the same time period, also shows a similar trend.

The leading cause of reactor trips provided in the *AEOD Annual Report, 1994-FY 95,*[58] is equipment failures initiated by problems primarily in the main feedwater system. Problems with main feedwater tend to result in the need for auxiliary feedwater, particularly if a low steam generator water level condition results. Overall, while the frequencies of AFW system unplanned demands and PWR reactor trips are different, a significant portion of the causes for the demands and trips are related. As a result, it appears that the decrease in AFW unplanned demands is related to the decrease in reactor trips caused by main feedwater related equipment problems.

4.1.1.2 Segment failures. Figure 14 shows the frequency of AFW segment (includes all types of segments) failures observed during unplanned demands for each calendar year over the study period. The frequency of any segment failure during an unplanned demand was about 0.0075, and the trend in this frequency was not statistically significant (P-value = 0.15). This indicates that while the number of unplanned demands has decreased over the study period, the probability of observing a segment failure varied year-to-year with no statistically significant trend.

To determine if any one segment type had a significant trend, the AFW segment failures were partitioned by the three major segment types: motor-driven pump, turbine-driven pump, and feed control. Figures 15, 16, and 17 show the results of the trend analysis for these three segment types. As shown in the figures, only the feed control segment had a decreasing trend that was statistically significant (P-value = 0.04). The motor- and turbine-driven segments had no statistically significant trend over the study period (P-values = 0.10 and 0.19, respectively).

For each of the three segment types, a review of the causes of the failures was performed for each year of the study period in an effort to determine if the cause of the failures had an influence on the observed trends. 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.

The review of the causes of the motor-driven pump segment failures over the study period indicated that maintenance-related errors contributed to approximately half of the failures and were equally distributed throughout the study period. The remaining failures were caused by hardware-related problems, design errors, and personnel errors. The distribution of these three cause categories over the study period did vary considerably. Specifically, all the failures attributed to hardware-related problems occurred prior to 1990, and all the design-related problems and personnel errors occurred from 1990 to the end of the study period. This indicates that while the frequency of motor-driven pump segment failures had no statistically significant trend, the causes of the failures over the study period changed.

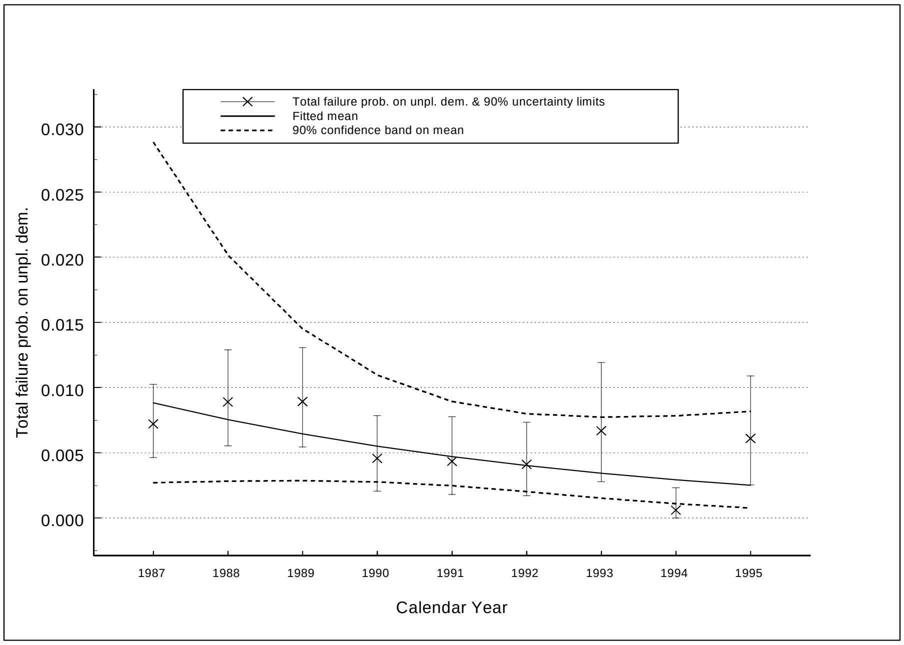


Figure 14. Failures per unplanned demand trended by calendar year, based on a constrained noninformative prior and annual data. The trend is not statistically significant (P-value = 0.15).

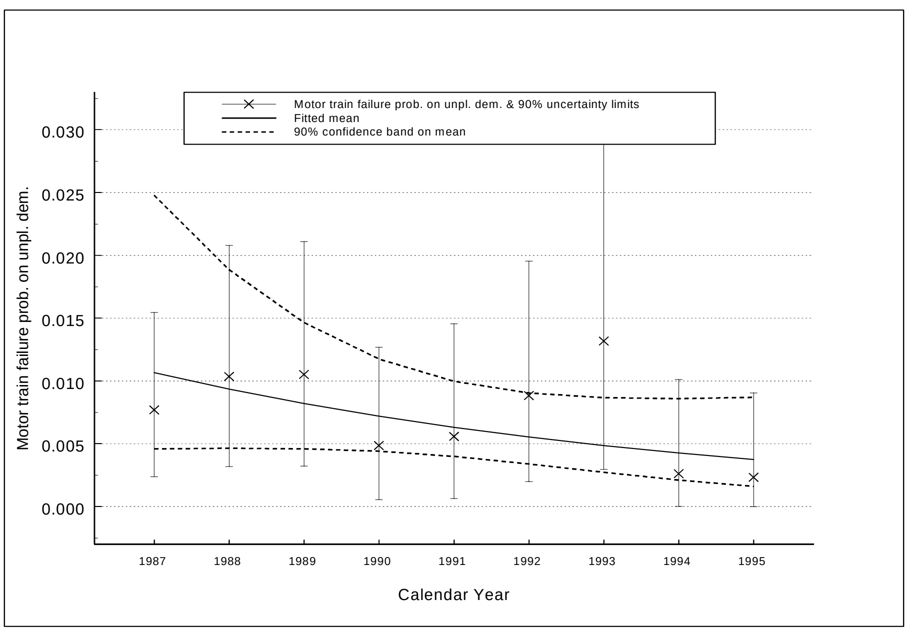


Figure 15. Motor-driven pump segment failures per unplanned demand trended by calendar year, based on a constrained noninformative prior and annual data. The trend is not statistically significant (P-value = 0.10)

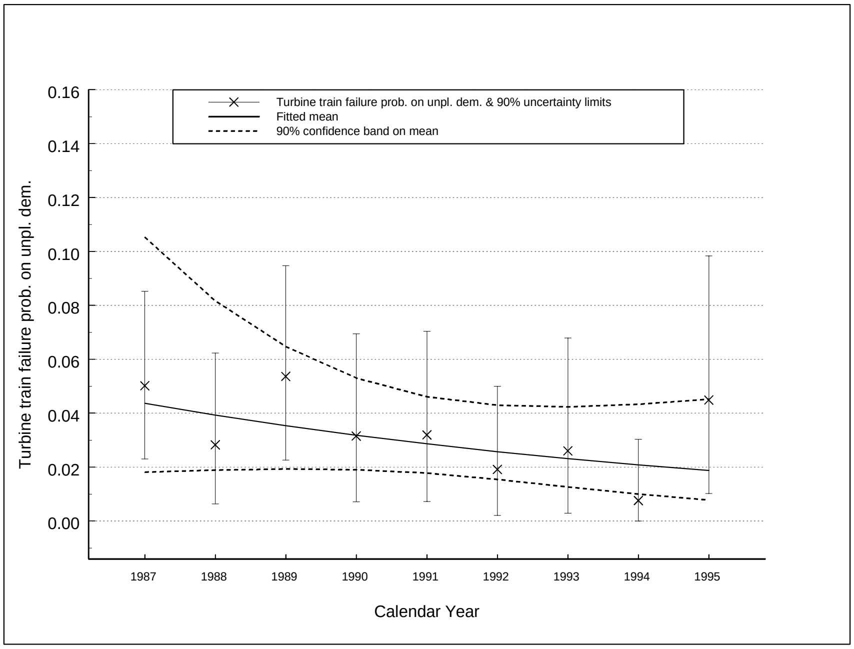


Figure 16. Turbine-driven pump segment failures per unplanned demand trended by calendar year, based on a constrained noninformative prior and annual data. The trend is not statistically significant (P-value = 0.19).

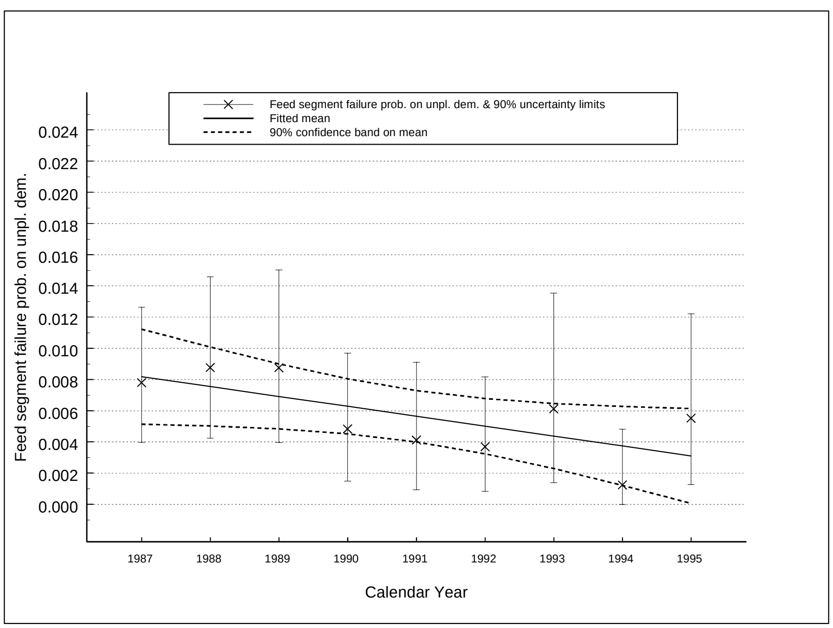


Figure 17. Feed segment failures per unplanned demand trended by calendar year, based on a constrained noninformative prior and annual data. A decreasing trend is statistically significant (P-value = 0.04).

The review of the causes of the turbine-driven pump segment failures over the study period indicated that the distribution of the causes changed in 1990. Prior to 1990, no one cause clearly dominated the turbine-driven pump segment failures. However, from 1990 to the end of the study period, seven of the eight turbine-driven pump segment failures were hardware related. This indicates that while the frequency of turbine-driven pump segment failures had no statistically significant trend, the causes of the failures over the study period changed. Specifically, failures attributed to hardware-related problems dominated the turbine-driven pump segments from 1990 to the end of the study period.

The review of the causes of the feed control segment failures indicated that the distribution of the causes of the failures varied over the study period. However, failures attributed to hardware-related problems and personnel errors were relatively constant over the study period. Prior to 1990, there were two events affecting six segments attributed to environment, and from 1990 to the end of the study period, there were none. Also, all (two) of the failures attributed to design-related problems occurred after 1990. In addition to the change in observed design and environment-related problems, the number of events involving two or more segments was almost three times higher prior to 1990 as compared to 1990 to the end of the study period. Specifically, prior to 1990, there were five events resulting in 14 segment failures, and from 1990 to the end of the study period, there were only two events resulting in four segment failures. Overall, while the causes of the feed control segment failures did change somewhat over the study period, the decrease in events resulting in two or more failures, from all causes, had a greater influence on the observed trend.

4.1.2 Trends by Low-Power License Date

To give some indication of the effect of plant aging (i.e., older plants versus newer plants) on AFW performance, a trend of plant-specific unplanned demand frequency and segment failures per unplanned demands were plotted against the plant low-power license date. The plots are shown in Figures 18, 20, 21 and 25. Figure 19 is a plot of plant-specific automatic reactor trip frequency against the plant low-power license date. Figure 19 is provided for informational purposes only because of the relationship between unplanned demands and automatic reactor trips stated earlier. Included with each figure is the frequency per plant operating year and 90% confidence interval; a fitted mean and a 90% confidence band for the fitted mean are also provided for each figure.

As shown in Figure 18, the frequency of unplanned demands versus low-power license date shows an increasing trend for the newer plants. The increasing trend is highly statistically significant (P-value <5E-5). Figure 19 shows a similar trend for PWR automatic reactor trips. As discussed earlier, the AFW unplanned demand trend appears to be related to the trend in automatic reactor trips. In addition, a review of the events that occurred at the plants that received a low-power license after January 1, 1987, indicated that approximately 70% of the unplanned demands occurred within 2 years of the low-power license date.

As shown in Figure 20, the frequency of motor-driven pump segment failures versus low-power license date shows a statistically significant (P-value=0.0001) decreasing trend for the newer plants. An examination of the motor-driven pump failures based on low-power license date indicated that there were 13 failures attributed to plants licensed before 1980 and only two failures attributed to plants licensed after January 1980. (January 1980 was chosen because it represented a natural break point in the data. Specifically, there were no failures observed from plants licensed from late 1977 to January 1980.) A review of the causes of the failures showed that for the failures associated with plants licensed prior to 1980, five were classified as maintenance related, five as hardware related, and three as design problems.

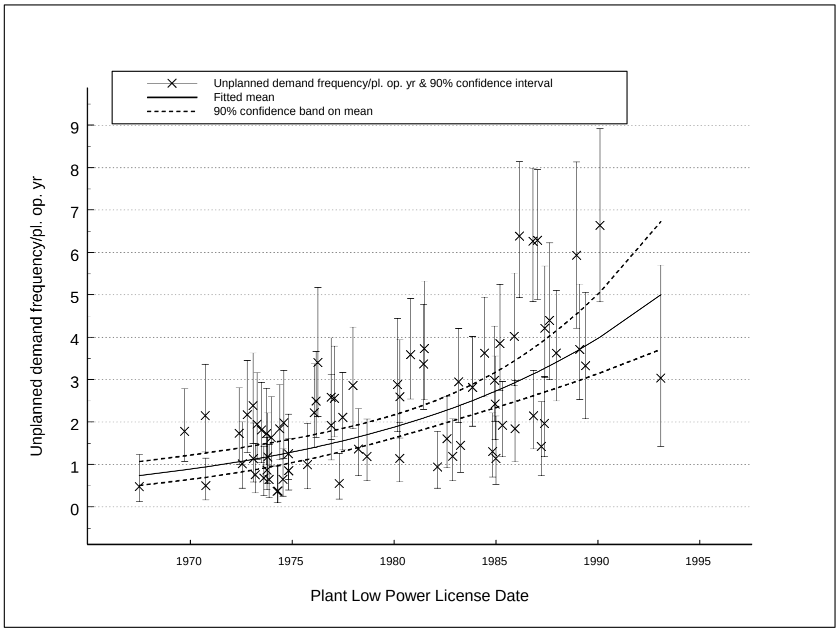


Figure 18. Unplanned demand frequency versus low-power license date, with confidence limits on the frequencies. The increasing trend is highly statistically significant (P-value <5E-5).

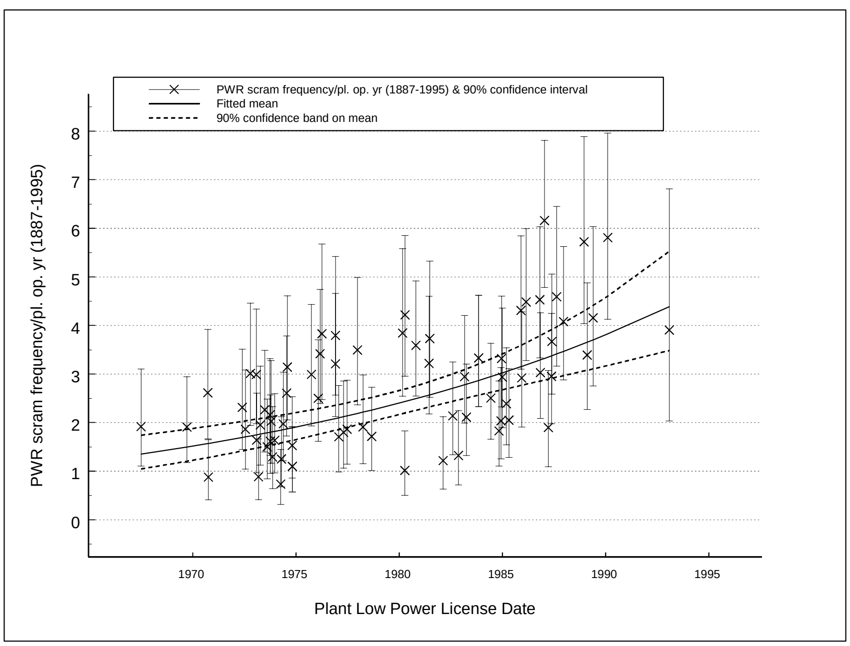


Figure 19. PWR scram frequency for 1987–1995 plotted against low-power license date, with confidence limits on the frequencies. The increasing trend is highly statistically significant (P-value <5E-5).

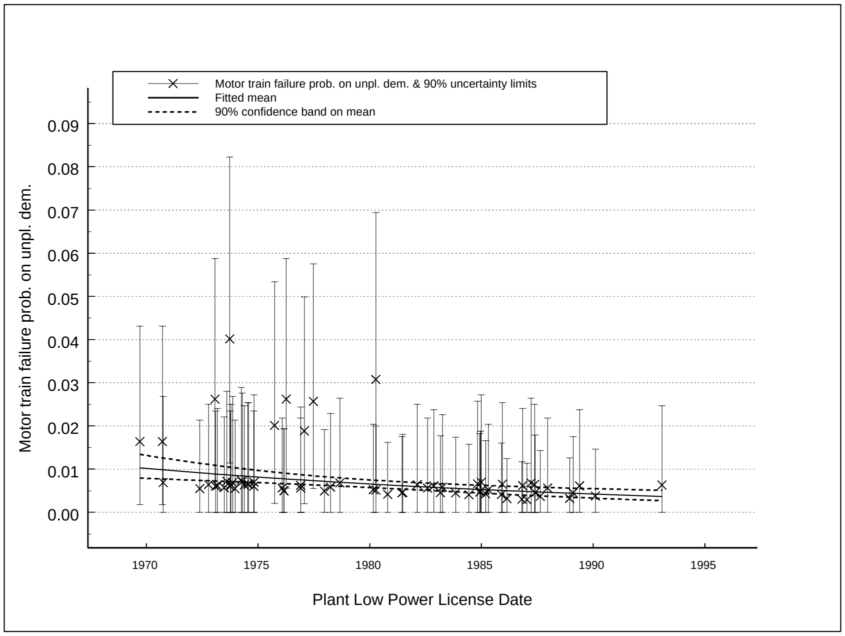


Figure 20. Motor-driven pump segment failure probability per demand, based on a constrained noninformative prior distribution, plotted against low-power license date. The decreasing trend is statistically significant (P-value = 0.0001).

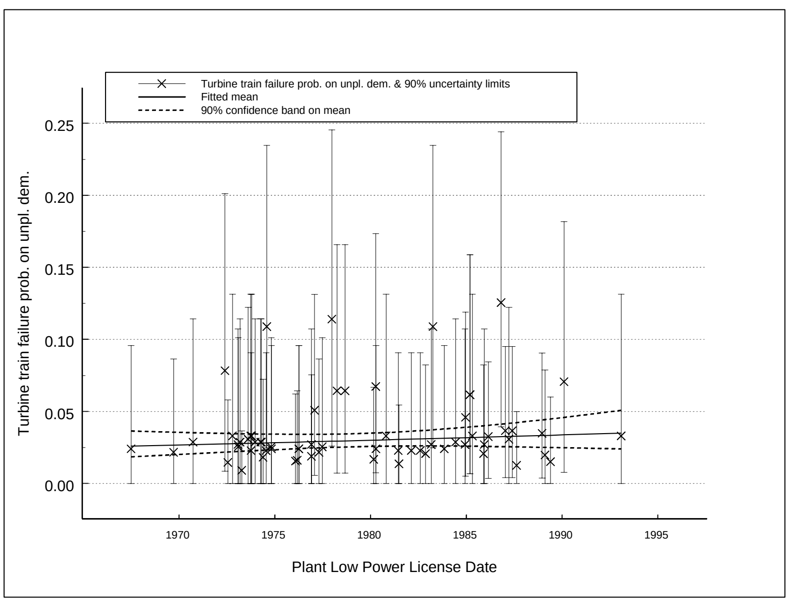


Figure 21. Turbine-driven pump segment failure probability per demand, based on a constrained noninformative prior distribution, versus low-power license date. The trend is not statistically significant (P-value = 0.32).

The five maintenance-related failures were the result of incorrect performance of maintenance activities and were not associated with an aging issue. The five hardware-related failures could be attributed to age-related failures. Two were the result of cracked channel ring vanes, two were the result of failed relays, and the remaining failure was attributed to a failed control switch. The three design-related problems were failures caused by operating the system differently than designed or tested. These failures were not attributed to an aging issue. The two failures that were observed at plants licensed after January 1980 were the result of a personnel error in operation of the system.

As shown in Figure 21, the turbine-driven pump segment failure probability per demand shows no significant trend with respect to low-power license date. The trend is not statistically significant (P-value = 0.32).

As shown in Figure 22, the feed segment failure probability per demand does not show a significant trend with respect to low-power license date. The trend is not statistically significant (P-value = 0.44). Although no trend with respect to plant low-power license date was found for feed segment failure probabilities on unplanned demands using the constrained noninformative prior distribution, a decreasing trend was seen for the 16 plants for which failures occurred. Two factors make the apparent trend inconclusive in the complete data set. First, the older plants having failures have relatively few feed segment demands within the study period. Demands ranged from 10 to over 300, with the lower numbers generally for the older plants (having fewer AFW unplanned demands). The variance in the probability estimates is higher when the demands are few. Second, the existence of many older plants (as well as newer ones) with no feed segment failures reduces the evidence for a decreasing trend in feed segment failure probabilities as the plants age.

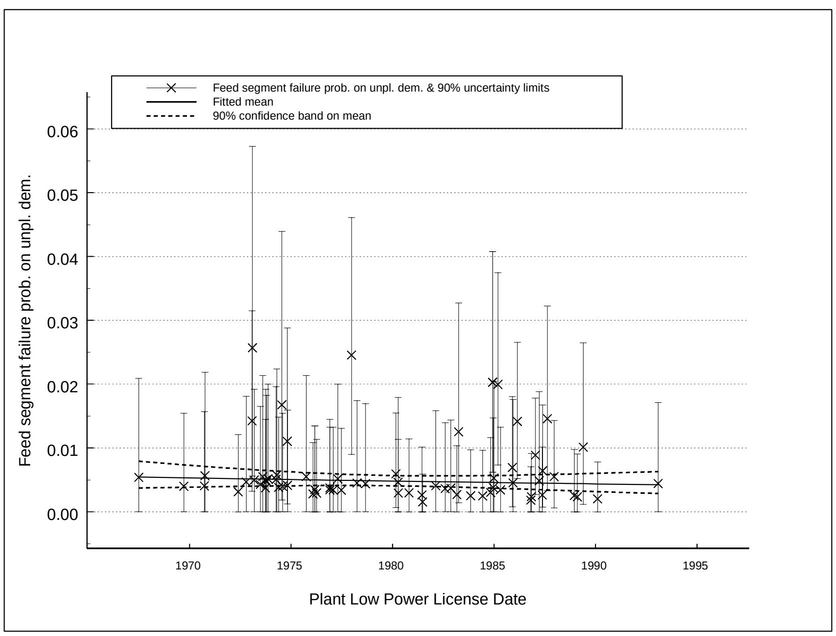


Figure 22. Feed segment failure probability per demand, based on a constrained noninformative prior distribution, plotted against low-power license date. The trend is not statistically significant (P-value = 0.44).

4.1.3 Trends in Calendar Year and Age, Considered Together

The rate of unplanned demands was analyzed in both Section 4.1.1 and Section 4.1.2. In the first section, the rate was shown to be decreasing with calendar year, when the plant data were pooled within each year. In the second section, the same rate was shown to be increasing with low-power license date, when the data from 1987 to 1995 were pooled within each plant. This trend was interpreted as a decreasing trend with plant age. Both trends were plausible: the calendar year reflects industry-wide culture and regulations, which have resulted in a decreasing rate of scrams, and plant age reflects the experience and learning at the particular plant. Because calendar year and plant age are closely related—a plant experiences increasing calendar year and increasing age together—the effects of the two variables were analyzed in a single model, presented here.

The fitted model was

$$\log\lambda = 9.78451 - 0.09669\times\text{year} - 0.10347\times\text{age} + \text{random plant effect},$$

with λ expressed as events per plant operating year, and $\log\lambda$ denoting the natural logarithm. In the data analysis, the calendar year was expressed as a two-digit number, from 87 through 95, and the plant age was counted as years elapsed since the low-power license date. The form of the model, linear in $\log\lambda$, was assumed, and the numbers were estimated from the data.

Both slope terms, for year and age, were statistically very significant (P-value = 0.0001). As time passes, any specific plant undergoes both increasing calendar years and increasing age, so the change in $\log\lambda$ is the sum of the two terms, –0.20016 times the number of elapsed years. Therefore, in about 11.5 years, the average scram rate has decreased by a factor of 10. The random plant effect has standard deviation of 1.35. That is, about 5% of the plants have $\log\lambda$ above or below the industry median by 2.7 or more. Therefore, during short time periods, the variation between plants dominates the gradual time trend.

Figure 23 uses solid lines to show the industry mean of λ for hypothetical plants of several ages. In each plot, the dashed lines form a 90% prediction band, covering the entire line for a random plant with 90% probability. The figure illustrates that the rate decreases as time goes on, that older plants tend to have lower rates, and that a random plant can differ substantially from the industry mean.

Technical details of the analysis method are given in Section A-4 of Appendix A.

4.2 Factors Affecting AFW Reliability

The AFW 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 by segment type that occurred during an unplanned demand. Segment failures found as a result of a surveillance test or from other methods are presented only as a qualitative discussion. As discussed previously in Section 2.2, single train failures found during the performance of a surveillance test or by personnel tours, etc., are not required to be reported 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. This reportability requirement effectively censors any results that can be obtained using data other than that obtained during unplanned demands.

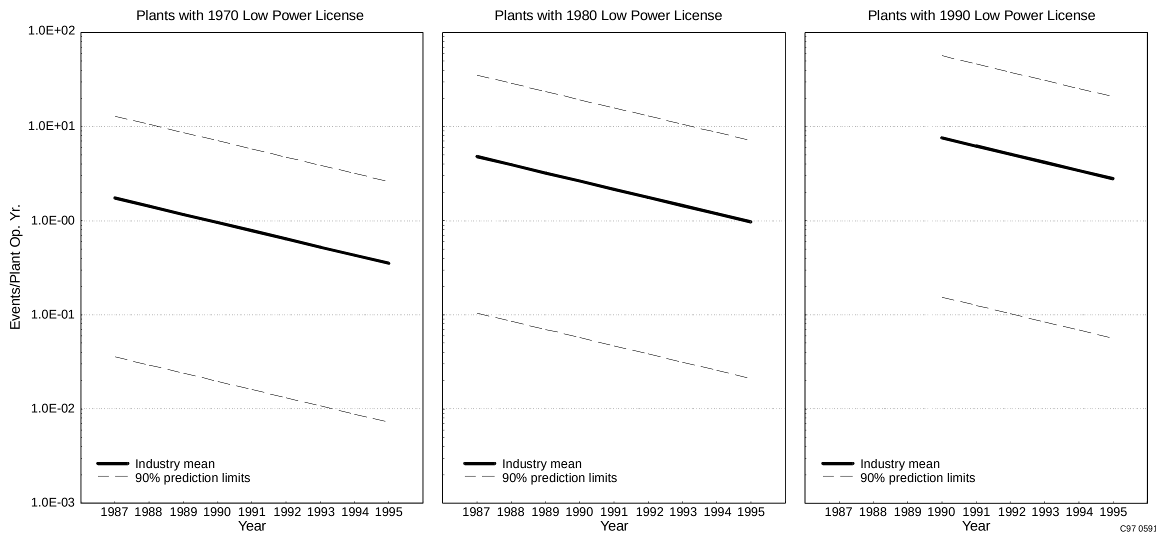


Figure 23. Rate of unplanned demands for the AFW system, for hypothetical plants of various ages. Solid lines show industry means, and the dashed lines are 90% prediction limits for a random plant.

Table 15 is a listing of the segment failures that occurred during an unplanned demand partitioned by the cause of the failure. Figure 24 is an illustration of the data provided in Table 15 for the segments that more than two failures were observed. Table 16 is a listing of the turbine- and motor-driven pump segment failures that occurred during an unplanned demand partitioned by the cause category and failure mode. Figure 25 is an illustration of the data provided in Table 16. Only the turbine- and motor-driven pump segments were partitioned by failure mode—the other segments failures were all classified as failures to operate. Therefore, as a result of the failure mode classifications, only the turbine and motor-driven pump segments required an additional data partitioning.

The reader is cautioned from making comparisons of the numbers provided in Tables 15 and 16 with the number of failures used in the unreliability analysis provided in the Section 3. The tables include the contribution of support system failures (which were not used in the unreliability analysis) and exclude the contribution of MOOS (which were 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 failure resulted in two motor-driven pumps failing to start, the tables shows two failures to start of motor-driven pumps, not one.

This section of the report is comprised of summary information relating to various factors that have affected AFW reliability. Section 4.2.1 provides insights into the failures that disabled the AFW system. Sections 4.2.2 and 4.2.3 discusses the causes for turbine-driven pump failures and motor-driven pump failures, respectively. The factors affecting feed-control segment reliability are presented in Section 4.2.4.

4.2.1 System Reliability

The AFW system consists of multiple independent trains, which overall increase the reliability of the system because a single component or train failure will not disable the system's safety function. However, there were nine instances observed in the unplanned demand data that more than one train was unable to complete its safety function. The types of events that resulted in multiple component or train failures were caused by either, an error of commission, failure of a common suction source, or common cause failures.

Table 15. Unplanned demand segment failures partitioned by cause category.[a]

Segment	Design	Envrnmnt[b]	Hardware	Mainten[b]	Persnnl[b]	Procdre[b]	Supprt[b] Sys	Water Accum[b]	Total
Diesel-driven pump	—	—	2	—	—	—	—	N/A	2
Feed control	2	2	18	4	6	—	—	N/A	32
Instrumentation	—	—	—	—	—	—	2	N/A	2
Motor-driven pump	3	—	5	5	2	—	4	N/A	19
Suction	—	—	1	—	—	—	—	N/A	1
Turbine-driven pump	—	—	14	1	3	—	—	3	21
Turbine steam supply	—	—	1	—	—	—	—	—	1
Total	5	2	41	10	11	—	6	3	78

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 support system failures (which were not used in the unreliability analysis) and excludes the contribution of MOOS (which were used in the unreliability analysis). 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; Water Accum = Water Accumulation.

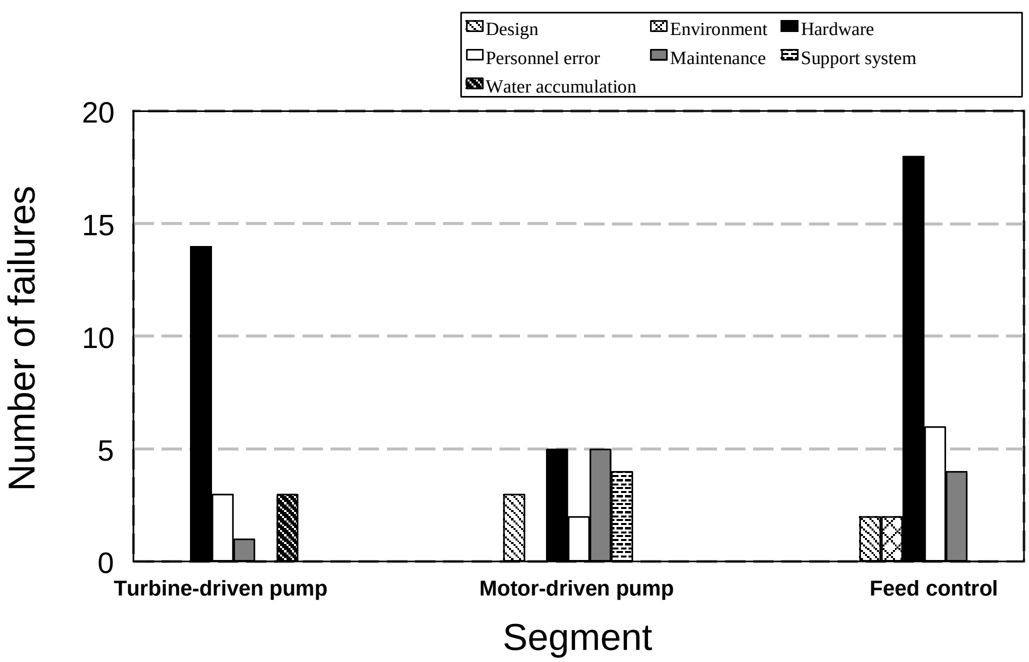


Figure 24. Illustration of the causes of segment failures.

Table 16. Unplanned demand segment failures partitioned by cause category and failure mode.[a]

Segment	Cause Category								
	Design	Envrnmnt[b]	Hardware	Mainten[b]	Persnnl[b]	Procdre[b]	Supprt[b] Sys	Water Accum[b]	Total
Turbine-driven pump									
Failure to run	—	—	3	—	1	—	—	—	4
Failure to start	—	—	11	1	2	—	—	3	17
Motor-driven pump									
Failure to run	1	—	2	—	2	—	—	N/A	5
Failure to start	2	—	3	5	—	—	4	N/A	14
Total[c]	1,2	—	5,14	0,6	3,2	—	0,4	0,3	9,31

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 support system failures (which were not used in the unreliability analysis) and excludes the contribution of MOOS (which were used in the unreliability analysis). 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; Water Accum = Water Accumulation.

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

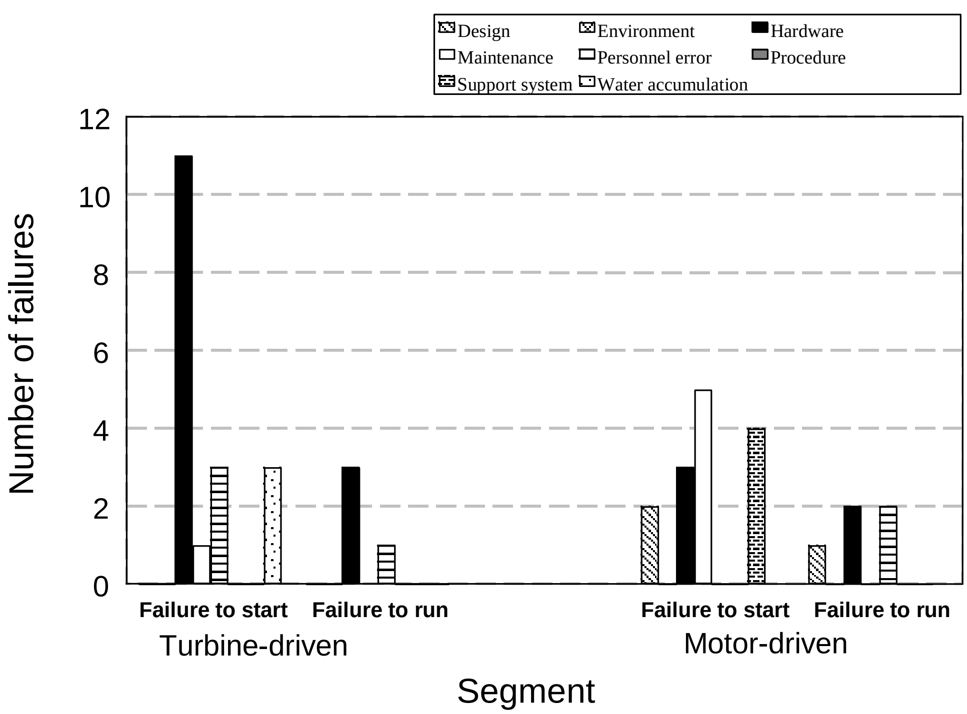


Figure 25. Distribution of the causes of unplanned demand failures by failure mode.

4.2.1.1 Error of Commission. In the operational data consisting of unplanned demands, there was one event in which all three trains of AFW were intentionally disabled by operator action when the system was required to be in operation by plant technical specifications. Specifically, following a reactor trip, the AFW pumps automatically started on low-low steam generator level. During subsequent recovery actions from the reactor trip, it was noted that the reactor coolant system was experiencing a cooldown as a result of feeding the steam generators with relatively cold water from the AFW system (which is a normal occurrence following a reactor trip and AFW pump start). An operator became concerned with the reactor coolant system cooldown rate when the temperature decreased to approximately 540°F. To reduce the steam generator feedwater addition rate and stabilize the reactor coolant system temperature, the ATWS mitigation system actuation circuitry was reset, and the AFW pumps were secured in a manner that rendered them inoperable before steam generator levels were restored above the automatic start setpoint (The control switches were placed in "pull-to-lock," and the steam supply valves to the turbine-driven pump were closed.) The procedure required AFW flow to be throttled to 400 gpm if the cooldown continued. In addition, the operator that performed the action did not inform control room personnel of this action.

Subsequently, approximately 19 minutes later (when the steam generator low-low level alarms cleared), the emergency procedure reader noticed that the AFW pump status did not conform to the appropriate emergency procedure step and immediately notified the shift supervisor, who directed the pumps to be returned to AUTO. During the period of time that the AFW pumps were inoperable, main feedwater was the makeup water source for the steam generators. This event was identified by the Accident Sequence Precursor (ASP) Program (NUREG/CR-4674)[59] and was assigned a conditional core damage probability (CCDP) of 1.1E-6.

Many of the same AFW initiation signals also result in a main feedwater isolation signal. In addition, generally a reactor trip results in a turbine trip which results in a main feedwater isolation. (Some designs require a coincidence signal of reactor trip and low reactor coolant temperature to receive a feedwater isolation.) In this event main feedwater was isolated and AFW was the only source of feedwater to the steam generator. While North Anna does have electric main feedwater pumps the feed control valves were closed.

The event was classified as an error of commission as a result of a plant operator intentionally disabling the function of AFW with steam generator levels below the automatic start setpoint. Defeating the automatic start capability of the AFW pumps is prohibited by technical specifications during this situation. In addition, the IEEE Standard, *Criteria for Protective Systems for Nuclear Power Generating Stations, ANSI/IEEE Std. 279-1971*,[60] requires that once a protective system is initiated, it is required to go until completion (i.e., steam generator levels above the low-low setpoint), and if the protective action of some part of the system has been bypassed or deliberately rendered inoperable for any purpose, this fact shall be continuously indicated in the control room. From the information provided in the LER and in NRC Resident Inspector Reports 50-338/93-17 and 50-339/93-17,[61] the actions by the control room operator were not in accordance with plant technical specifications or the IEEE Standards.

A review of AFW risk-based inspection guides[62-68] indicated that the dominant cause of AFW system multiple-train failures has been human error. The inspection guides identified two events that indicate that the above error of commission event is not an isolated occurrence. (The events occurred prior to 1987 and, therefore, were not used in the unreliability estimation provided in Section 3.) The two events identified in the inspection guides were the result of human error in the form of incorrect operator intervention into automatic AFW system functioning during transients that resulted in the temporary loss of all safety-grade AFW pumps. The events occurred at Davis-Besse (NUREG-1154[69]) and Trojan (AEOD/T416[70]`). In the Davis-Besse event, improper manual initiation of the steam and feedwater rupture control system led to overspeed tripping of both turbine-driven AFW pumps, probably as a result of the introduction of condensate into the AFW turbines from the long unheated steam supply line. (The system had never been tested with the abnormal, cross-connected steam supply lineup that resulted). In the Trojan event, the operator incorrectly stopped both AFW pumps as a result of misinterpretation of main feedwater pump speed indication. The diesel-driven pump would not restart as a result of a protective feature requiring complete shutdown, and the turbine-driven pump tripped on overspeed, requiring local reset of the trip and throttle valve.

In addition to the event where all AFW trains were disabled by operator action, there were three other events in which operator action rendered at least one train inoperable when it was needed to restore or maintain steam generator levels. The events were classified as personnel errors; however, they have similar characteristics to the error of commission. These instances were the result of (1) being unable to control steam generator levels, (2) the shutdown of an operating pump when no other method was available to feed the steam generator, and (3) opening system cross-connect valves, thereby causing two trains of AFW flow to be discharged to a test line when flow was needed to restore steam generator level.

The first event occurred when control room operators were unable to control steam generator levels following a reactor trip. During the subsequent recovery actions, the turbine-driven pump was shut down because of a casing drain steam leak with steam generator levels above the autostart setpoint for the turbine-driven pump. A few minutes later with both motor-driven pumps running, multiple low-low steam generator level alarms were received, resulting in a re-start of the turbine-driven pump. The LER stated that operators were unable to control or maintain steam generator levels with both motor-driven pumps running. This event was classified as a personnel error as a result of operators being unable to maintain steam generator levels above the low-level AFW actuation setpoint with both motor-driven pumps in operation.

The second event occurred when control room operators deliberately shut down a turbine-driven pump to limit plant cooldown. In this event, the turbine-driven pump was shut down with steam generator levels above the autostart setpoint; however, no other means of feeding the steam generator was available at the time. At the plant where this event occurred, each AFW pump supplies one steam generator; therefore, shutting down any pump results in no AFW flow to the associated steam generator. Within a very short period of time after the turbine-driven pump was shut down, multiple steam generator low level alarms occurred, resulting in a re-start signal to the turbine-driven pump. However, because the turbine was still coasting down from the previous operator-initiated trip, the turbine immediately tripped on overspeed. The event was classified as a single train failure as a result of a personnel error because of shutting down an AFW pump to a steam generator with no other feedwater flow available to the steam generator.

The third event related to an error of commission occurred during the post-reactor trip recovery process, and was the result of incomplete restoration from a previous surveillance test. During the recovery, control room operators observed that the “A” steam generator level continued to decrease even though the “A” motor-driven AFW pump flow indicated approximately 600 gpm. The "A" motor-driven AFW pump was secured after receiving a low discharge pressure alarm. Cross-connect valves were opened in an attempt to feed “A” steam generator from a different AFW pump segment; however, this proved unsuccessful. Subsequently, the "A" motor-driven pump recirculating test valve was discovered to be locked open instead of being in the required locked closed position. This condition diverted AFW flow back to the storage tank, thereby preventing AFW flow from entering the steam generator. The recirculation test valve was closed, and AFW flow was established to the steam generator.

The event was classified as a single train personnel error as a result of opening the cross-connect valves and subsequently connecting an operating segment to a faulted segment, essentially faulting both segments. From an operational perspective, the initial indications in the control room for “A” motor-driven pump segment was that the pump was running and providing 600 gpm flow; however, steam generator level was not recovering. These indications, high pump flow and steam generator level decreasing, are indicative of a header leak. Therefore, the actions taken by plant operators to cross-connect a properly operating segment to a segment with indications of a header leak was judged as a personnel error failing the properly operating segment.

Along with the personnel error related events that occurred during an unplanned demand, there were five instances in which operators disabled the system safety function when the system was required to be capable of an automatic start per plant technical specifications. In three of these instances, operators completely shut down the system after an automatic start, thereby rendering the system incapable of an autostart. In one of these instances, the system was left completely shut down following a reactor trip and was not noticed until the plant had returned to power operators 4 days later. In a fourth instance, operators completely disabled the automatic start function by pulling fuses (an action prohibited by plant technical specification) to perform a main feedwater pump trip check as a matter of expediency. In the final instance, an operator inadvertently isolated the suction sources for the motor-driven pumps with the turbine-driven pump out of service for maintenance.

4.2.1.2 Suction Segment. The failure, observed in the unplanned demand data of a suction segment, occurred following a reactor trip caused by a loss of steam generator level control. The AFW motor-driven pumps were demanded a few seconds after the reactor trip, and within 4 seconds of the pump start, a loss of normal suction alarm was received in the control room. Within a few seconds of the alarm, one header of the AFW suction automatically shifted to the nuclear service water system, which provides an assured source of water.

The automatic switchover to the nuclear service water system occurred as a result of an actual low AFW suction pressure condition. The low suction pressure condition was a result of operating with the AFW condensate storage tank isolated, while not maintaining adequate level in the upper surge tank, which provides an alternate source of feedwater to AFW. The AFW condensate storage tank had been isolated due to leakage. At the time of the transient, the upper surge tank was thought to be 95% full. However, the chart recorder used for level indication was later discovered to have been broken and indicating a false trace at 95%. The actual level of the upper surge tank was approximately 65%.

After the switchover to the assured source, an additional failure occurred that affected multiple feed control valves. After the initial trip recovery, it was noted that AFW flow to two steam generators had degraded following the suction switchover. Inspection of the internals of the AFW flow control valves revealed that the cavitrol cages for these valves were clogged with shredded Asiatic clam shells. Following discovery, all AFW pumps for both units were declared inoperable. The reduced flow to the steam generators was attributed to clam larvae from a nearby lake entering the nuclear service water system and growing to maturity in normally stagnant lines, which provide assured water supplies to various safety related systems. The clams were removed from the AFW and nuclear service water systems prior to unit startup. This event was identified by the ASP Program and was assigned a CCDP of 2.7E-4.

In addition to the suction segment failure that occurred during an unplanned demand, there were two other events in which the backup source of water would not have functioned for a PRA mission. These two failures, while not contributing to the unreliability estimate provided in Section 3 (because of the method of discovery), do provide additional insights into the importance of the backup water supply to the AFW system. One of these two failures occurred during a surveillance test, and the other was found during an engineering review.

The surveillance test failure of a suction segment occurred as a result of clam and sludge intrusion into the backup suction supply source. The plant was in hot shutdown following a refueling outage. During the outage, turbine-driven pump modification and preventive maintenance had been done, and extensive motor-operated valve testing of the cooling water supply valve had taken place. Operability testing of the pump was in progress. Several pump starts were made. On two of the starts, the pump tripped on overspeed. The operator was able to keep the pump running on a subsequent start, but the discharge pressure was only 200 psig. Expected discharge pressure is about 1,650 psig. The pump was disassembled and inspected; broken clam shells and sludge were removed from the pump casing, and a few clam shell pieces were removed from the first and second stage impellers. The pump operated satisfactorily after reassembly. All AFW pumps at both units were flushed; similar amounts of foreign material were removed from the other pumps. The cause of this failure was the presence of a mixture of sludge and broken clam shells located in the cooling water supply line to the AFW pump. This mixture was moved into the suction piping of the auxiliary feedwater pump when the backup source of water was used to test the motor-operated valve operation with a differential pressure.

The other suction segment failure was the result of air formation in the suction piping. The occurrence of air formation in two different locations in the nuclear service water suction was determined by plant engineering personnel during an extensive piping and configuration evaluation. The air was forming in high points of the nuclear service water discharge piping, and was capable of being introduced into the AFW system through the nuclear service water system assured makeup branch connections during a PRA mission.

Off-gassing was determined to be the source of the air found in the nuclear service water discharge header. The process of off-gassing in the service water discharge header was not recognized during the design phase. Dissolved gases (nitrogen/oxygen) were coming out of solution as the service water temperature increases while removing heat from various plant components. The dissolved gases were migrating to high points in the discharge piping where flow velocities are low. Additionally, at the plant discovering the problem, the nuclear service water assured makeup connections tie in at the top of the nuclear service water piping, thus allowing air (dissolved gases) to accumulate in this piping. Even though the system contains vents, these vents were installed during plant construction for startup and maintenance activities and were not required to be open for the purpose of continuous venting. An NRC Information Notice 93-12: *Off-Gassing in Auxiliary Feedwater System Raw Water Sources*[71] was written based on the event to highlight the potential for off-gassing in auxiliary feedwater raw water sources.

The risk-based inspection guides also identified another potential failure mechanism associated with AFW suction piping. The inspection guides identified undersized suction piping at several plants. The undersized piping was found when simultaneous startup of multiple pumps had caused oscillations of pump suction pressure, causing multiple pump trips on low suction pressure, despite the existence of adequate static net positive suction pressure. One instance of inadequately sized suction piping was observed in the operational data selected for the study. This event was identified during an engineering design review and, as a result, did not contribute to the unreliability estimate.

4.2.1.3 Common Cause Failure. In the unplanned demand data, there were events in which multiple segments were failed as a result of a common cause mechanism. Four of the instances involved failures of the feed control segments to operate, two instances involved the motor-driven pump segments, and one involved both the motor- and turbine-driven pump segments. The failures associated with the motor-driven pump segments were both failures to start. The failure that affected both the motor- and turbine-driven pump segments was classified as a failure to run.

The common cause failures associated with feed control segments were caused by two hardware problems, an environmental problem, a personnel error, and a maintenance error. The hardware problems were failures of the feed control valves to control steam generator level in the automatic mode caused by malfunctions of the control circuitry. The valves either throttled closed farther than required, resulting in reduced flow to the steam generator, or opened fully, resulting in overfilling the steam generator and possibly causing a high pump flow condition. In both instances, operators were able to take manual control of the valves and control steam generator levels. The environmental problem was the result of Asiatic clam intrusion into the system, causing a significant reduction in flow to two steam generators. The personnel error occurred when operators were unable to control steam generator levels using only the motor-driven pumps. With both motor-driven pumps operating, steam generator levels could not be maintained above the automatic start setpoint of the turbine-driven pump. Steam generator levels reached the automatic start setpoint of the turbine-driven pump, and the pump started as required. The turbine-driven pump was shut down a few minutes prior to the demand because of a casing drain line steam leak. The maintenance problem resulted from the torque switches for the motor-operated valves being set at too low a torque value. When the valves started to throttle closed from the normal full open position to control steam generator level, the torque switches tripped, stopping the motor-operator. To prevent steam generator overfill, the control room operator tripped the motor-driven pump after the two steam generator levels recovered above the automatic start setpoint.

One of the common cause failures of the motor-driven pumps failing to start on demand was the result of a design problem associated with the low suction pressure shutdown setpoint. The low-pressure shutdown setpoint problem was a result of the switches for both motor-operated pumps being set at too high a pressure (the set pressure was in accordance with established procedure and did not preclude successful performance of surveillance tests). As a result, during a low steam generator water level transient, the pumps would not start with a lower-than-normal suction pressure. The lower-than-normal pressure condition in the pump suction was the result of previous operator actions to maintain main feedwater flow. Plant operators had opened a high-volume makeup line from the condensate storage tank to the hotwell in an attempt to recover hotwell level and maintain main feedwater flow. Main feedwater was subsequently lost, and a steam generator low-level condition resulted, causing an AFW initiation. With an open high-volume makeup line and with the low-pressure shutdown switches set high, insufficient suction pressure was available to clear the low-pressure shutdown to allow the pumps to start. The pumps automatically started after operators closed the high-volume makeup line isolation valve. This event was identified by the ASP Program and was assigned a CCDP of 3.6E-6.

The other common cause failure of the motor-driven pumps failing to start on demand was the result of a maintenance error associated with the pump circuit breaker. The maintenance error resulted in both motor-driven pumps failing to start in manual due to a wiring error in the breaker switchgear. This error was installed 18 months earlier. After the wiring error was discovered, it was found that the motor-driven pump breakers would not close with a main feedwater pump trip signal present, which is a normal automatic start signal for AFW. The switches that defeat the automatic start when both main feedwater pumps trip were taken from the AUTO position to the DEFEAT position, which allowed the pumps to start. This event was identified by the ASP Program and was assigned a CCDP of 1.1E-6.

In addition to these common cause failures observed during unplanned demands, an NRC Information Notice, No. 87-94: *Single Failures in Auxiliary Feedwater Systems*,[72] provided supporting information concerning the potential for single failures of the auxiliary feedwater pump start and protective pump trip circuitry. In one of the events identified in the Information Notice, a licensee identified a potential single failure in a portion of the pump start circuitry that is common to both motor-driven pumps that could prevent both pumps from starting automatically in the event of either a low-low steam generator level or loss of main feedwater. At this plant, the start circuitry was designed so that the steam generator level and loss of feedwater start signals were routed through contacts of the safety injection inhibit relays. The purpose of these relays is to delay pump starts under safety injection conditions until the safety injection sequencer calls for the pumps to start at the appropriate time. If the contacts of either inhibit relay failed in the open position, neither the low steam generator level nor loss of feedwater start signals would cause the pumps to start. Moreover, the Information Notice identified similar occurrences at other plants where the AFW trip circuitry did not meet the single-failure criterion. In one instance, a design modification to provide protection from tornado damage to the auxiliary feedwater storage tank could fail the AFW system. Single failure vulnerabilities were found stemming from a single test switch, a single suction pressure instrument, and a single low suction pressure trip output relay. Failure of any one of these protective features could have resulted in tripping all three AFW pumps.

The one common cause failure that occurred, which affected both the motor- and turbine-driven pump segments, was a result of a pump problem, not related to the pump driver. During an unplanned demand, AFW flow was noticeably reduced to a steam generator. Subsequent detailed and extensive inspection, which included fiber-optic inspections of piping and flow control valve internals, revealed no indication for the problem. Surveillance tests were performed, and flow rates during the tests were normal. A few months later, AFW was again demanded following a reactor trip, and flow rates were 1/3 of normal to a steam generator. Inspection revealed metal pieces in the flow measuring orifice venturi to two steam generators. The metal pieces were from the AFW pumps. All three pumps were inspected, and each pump was missing pieces of the channel ring vane.

Along with the common cause failures observed during unplanned demands, there were 31 instances where more than one segment would not have been able to respond to a steam generator low level transient when it was required to be operable by plant technical specifications. These 31 instances were discovered either through the course of routine surveillance tests or other plant activities (e.g., plant tours, operator inspections, and design reviews). The failures were primarily the result of personnel errors. These errors consist of either completely shutting down the system after a demand, thus rendering it incapable of automatically starting, or failing to align the system for automatic start prior to a mode change. The other significant contributor to these failures was procedure problems. The procedure problems were the result of insufficient direction for the performance of surveillance tests such that the system is rendered incapable of automatically starting given a demand. Also, some plants were intentionally entering technical specification action statement 3.0.3 to perform a test (i.e., rendering all the AFW pumps inoperable). In addition to these failures, there were two events where all the AFW pumps at a site were rendered inoperable. These two events were caused by stress corrosion cracking of the pump impellers, and necessitated the replacement of all the AFW pump impellers at two sites.

A review of the AFW risk-based inspection guides for the mechanisms of common cause failures indicated that the dominant cause of AFW system multiple-train failures has been human error. Design/engineering errors and component failures have been less frequent (but nevertheless significant) causes of multiple train failures. The mechanisms of common cause failures observed from the operational data selected for this study was similar to the mechanisms of common cause failures identified in the risk-based inspection guides. There was however, one difference; the inspection guides did not identify common cause failures of the pump internals as a contributor, which were observed in the operational data.

4.2.2 Turbine-Driven Pump Reliability

There were 22 failures of the turbine-driven pump segment: 17 were classified as failures to start and four as failures to run. These events were primarily the result of hardware failures. Personnel error in operation of the segment, water accumulation in the steam lines/turbine, and a problem resulting from a maintenance activity contributed to the remaining failures.

4.2.2.1 Hardware Category. As shown in Table 16, there were 14 failures assigned the cause category of hardware: three were failures to run and 11 were failures to start. Two of the three failure to run events resulted in turbine overspeed trips. All of the failures to start also resulted in a turbine overspeed trip.

For the hardware failures classified as failures to run, none of the failures were recovered by operator action. The one failure that did not result in a turbine overspeed trip was caused by a wiped turbine journal bearing. The bearing failure occurred after 25 minutes of operation. The two failures that resulted in turbine overspeed trips were attributed to different components. One was the result of a plug blowing out of the trip limiter and striking the trip linkage. The plug striking the trip linkage caused a mechanical overspeed trip, which was not recovered by operator action. This event was identified by the ASP Program and was assigned a CCDP of 1.4E-5. The other overspeed trip was the result of the governor being unable to control speed with the normal high steam pressure conditions that existed following a reactor trip. The turbine had been tested satisfactorily during previous surveillance tests at a lower steam line pressure.

Of the hardware failures classified as failure to start, four of the failures were caused by problems associated with the trip linkage either being out of adjustment, worn excessively, or stem binding. These types of problems typically result in a mechanical overspeed trip that requires the turbine to be reset locally rather than from the control room. As a result, only one of the failures was recovered by operator action. Three of these four failures were also identified by the ASP Program and were assigned CCDPs of 4.8E-4, 1.5E-5, and 1.7E-6, respectively.

NRC Information Notice 94-66, Supplement 1: *Overspeed of Turbine Driven Pumps Caused by Binding in the Stems of Governor Valves,*[73] provided additional data on the mechanism of these failures. According to the Information Notice, the visible cause of valve stem binding is corrosion product buildup on the valve stem. The corrosion product hinders movement of the valve stem within the surrounding packing assembly because of the small tolerances between the stem and the surrounding stainless steel washers. Based on metallurgical analysis, the corrosion products are formed due to galvanic corrosion, crevice corrosion, and pitting corrosion. The corrosion may be initiated by a combination of moisture, heat, trace impurities in the stem packing, materials used for the valve stem and washers, and mechanical factors.

At two plants identified in the Information Notice, a valve stem replacement was soon followed by additional failures. It appears that a change in valve stem material processing (i.e., from gaseous to liquid nitriding) in conjunction with conditions conducive to corrosion may lead to rapid failure. A study performed for a licensee reported that severe corrosion was known to have occurred at nine plants, and that all nine had valve stems made of 410 SS nitrided by using a liquid nitriding process. The Information Notice indicated that either type of nitriding of stainless steel is subject to galvanic attack when coupled to 410 SS without nitriding. If the layer of the nitriding is mechanically damaged, the underlying 410 SS may cause galvanic corrosion of the nitrided layer. As a solution, some plants have replaced the valve stem with an Inconel 718 stem because of its superior corrosion resistance.

Two of the failures to start were the result of contaminated governor hydraulic oil. One of these two oil-related failures was recovered. The failure that was not recovered was also identified by the ASP Program and was assigned a CCDP of 4.7E-6. The reasons for the contaminated oil were not provided in the LER; however, NRC Information Notice No. 86-14 Supplement 2: *Overspeed Trips of AFW, HPCI and RCIC Turbines,*[74] provided information related to contaminated governor hydraulic oil and its effects on turbine reliability. In addition to the two trips observed during unplanned demands, there were several oil-related trips during surveillance tests, and also the Information Notice identified several other turbine overspeed events related to oil contamination that occurred during testing. Many of the trips were recurring problems.

At one plant that experienced a large number of trips over a 2-month period, the licensee brought a field representative of Woodward Governor Company onsite to help determine the cause of the recurring overspeed trips. Subsequent inspection revealed that the control oil system was contaminated with dirt and grit. A thick gelatinous coating of dirt and hardened oil was observed on some governor components including the EG-R actuator and remote servo. The overspeed trips resulted from the contaminated oil that slowed the response of the governor. To correct the condition, the licensee changed the turbine lubrication oil and replaced the EG-R actuator. The preventive maintenance program provided for sampling the turbine lubrication oil each month and for changing the lubrication oil filter every 6 months. However, the program did not provide for periodic inspections of the oil sump and other components of the governor control oil system. Moreover, the vendor manual required a 5-micron oil filter; however, a 25-micron filter was being used. This resulted in a large quantity of particles of approximately 5 to 25 microns in the oil system, which caused a heavy accumulation of impurities in the governor and slowed the response time.

Of the remaining overspeed trips, three were related to the governor control system, and the others did not contain sufficient information in the LER concerning the overspeed trip to provide a more detailed discussion. One of the governor control system failures was the result of the governor being dynamically unstable. In this event, the turbine experienced speed oscillations during the ramp up to rated speed that resulted in an overspeed trip 52 seconds later. One was the result of a failed EG-M control box that caused an electronic overspeed trip that was recovered. This event was identified by the ASP Program and was assigned a CCDP of 1.2E-4. The other was owing to a spurious trip signal in one channel from the electronic tachometer. The trip signal from this source was determined by plant personnel as being unnecessary to protect against overspeed and its trip function was deleted. This failure could have been recovered by operator action; however, no attempt was made because the motor-driven pumps were operating and steam generator levels were being recovered. This event was identified by the ASP Program and was assigned a CCDP of 4.4E-6.

4.2.2.2 Maintenance Category. There was one failure to start event associated with a previous maintenance activity. This failure caused an electronic overspeed trip that was recovered by operator action. The overspeed trip was caused by an improper travel adjustment of the governor.

4.2.2.3 Personnel Error. As shown in Table 16, there were three failures assigned to the personnel error cause category. One was classified as a failure to run (error of commission), and the others as failures to start. Two of these events occurred as part of an effort by plant operators to limit plant cooldown following a high power reactor trip.

The failure to run event was recovered by operator action. In this event, the system was disabled by operator action with steam generator levels below the automatic start setpoint. This event was discussed previously as an error of commission.

For the failure to start events, both events were either recovered or judged as being recoverable. One of the failures to start occurred as part of an effort to limit plant cooldown. The turbine-driven pump was shut down after restoring the steam generator level. However, a few minutes later, the steam generator water level was reduced to the automatic start setpoint, resulting in a demand for the pump. The turbine tripped on overspeed during the start because the turbine was designed to start from a standstill and was still coasting down. At the plant where this event occurred, each AFW pump provides water to a specific steam generator. Therefore, a shutdown of an AFW pump results in no AFW flow to the associated steam generator, which perhaps accounts for why the low steam generator level automatic start setpoint was reached before the pump coasted to a standstill.

NRC Information Notice No. 86-14 Supplement 2 provided information related to the cause for overspeed trips during turbine coast-down. The Information Notice identified recurring turbine overspeed trips during testing. The overspeed trips occurred as a result of steam leaking past the steam admission valves, causing the turbine to rotate. The rotating turbine causes oil to be admitted into the governor's speed-setting cylinder. The combination of the turbine's initial rolling and the position of the speed-setting bushing can be sufficient to cause the turbine to trip on overspeed when the steam admission valves are opened during a turbine start sequence.

The other failure to start event was the result of the turbine casing drain valve being left open, resulting in a steam leak. The turbine was shut down because of the leak. This failure was recovered. In addition, while the pump was shut down because of the steam leak, operators were unable to maintain steam generator levels with only the motor-driven pumps operating.

4.2.2.4 Water Accumulation. As shown in Table 16, there were three failures assigned to the water accumulation cause category. These failures were all classified as failures to start and resulted in a turbine overspeed trip. Two of these failures were judged as being recoverable, and the third failure was not recovered by operator action. Two of these events were identified by the ASP Program and were assigned CCDPs of 1.3E-5 and 1.7E-6. Also, there was one instance in which water accumulation resulted in a reduced pump flow rate on startup. Once the water was clear of the steam lines, pump flow rate normalized. This event was not counted as a failure. In addition to the water accumulation problems observed during unplanned demands, there were eight other instances of water accumulation in the turbine steam lines, causing the turbine to overspeed on startup. These eight other failures were observed during surveillance tests. Moreover, an AEOD issued study, AEOD/C602, *Operational Experience Involving Turbine Overspeed Trips*[75] identified nine overspeed trip events that occurred as a result of undrained condensate in the turbine steam supply lines.

The LERs that reported water accumulation problems also referenced other previous LERs, some dating back beyond the study period, where water accumulation had caused turbine overspeed trips. In some of these events, the water buildup in the steam lines caused a large impact force on system check valves. The impact force was sufficient to separate the disc from the valve and deform the steam piping when the check valve disc came in contact with the pipe at a downstream elbow or bend.

The introduction of accumulated condensed steam into the turbine results in speed oscillations that exceed the overspeed trip setpoint. The water accumulation is attributed to steam traps that were left isolated from previous maintenance, stream trap strainers that clogged with magnetite, an insufficient number of steams traps to adequately pass the volume of condensate, leaking isolation valves, and design/placement of the steam traps relative to condensate collection areas (low points in the steam piping).

4.2.3 Motor-Driven Pump Reliability

There were 19 failures of the motor-driven pump segment: five were classified as failures to run and 14 were classified as failures to start. No one cause category accounted for a significant majority of the failures.

4.2.3.1 Design Category. As shown in Table 16, there were three failures classified as resulting from design problems: one was classified as a failure to run and two were failures to start. The two failures to start were the result of failures associated with the prime-mover, while the failure to run was not associated with the prime-mover. Both of the failures to start were recovered. The failure to run was not.

The failure to run event was a result of the location of the pump discharge check valve relative to the recirculation branch line. An operating motor-driven pump ("A" pump) was found with steam escaping from the shaft packing after 20 minutes of operation. The system cross-connect valves were open, and the "B" AFW pump was running with about 15 psig greater discharge pressure than the "A" pump. The higher discharge pressure from the "B" pump caused the "A" pump discharge check valve to close. With the minimum flow line located downstream of the discharge check valve, the "A" pump was running at shutoff head (no recirculation flow). This condition resulted in pump heat being transferred to the condensate, resulting in steaming through both pump shaft packing glands.

The two failures to start were also classified as a common cause failure. These failures were a result of the low-pressure shutdown switches for both motor-operated pumps being set at too high a pressure. As a result, during a low steam generator water level transient, the pumps would not start with a lower than normal suction pressure. This event was discussed previously in the common cause failure section.

4.2.3.2 Hardware Category. As shown in Table 16, there were five failures classified as resulting from hardware problems: two were classified as failures to run and three as failures to start. The two failures to run were not associated with the prime-mover. The failures to run were not recovered by operator actions. For the failures to start, one was associated with the pump and two were associated with the prime-mover. All of the failures to start were recovered.

The failures to run were associated with the pump, and were also classified as a common cause failure. The pump failures were indicated by reduced flow to a steam generator. Inspection of the piping to the steam generator revealed metal pieces in the flow measuring venturi to two steam generators. The three AFW pumps (two motor-driven and one turbine-driven) were inspected, and the channel ring vanes for all three pump were missing pieces. This event was discussed previously in the common cause failure section.

For the failures to start, malfunctions in the individual pump control circuit and in a flow control switch prevented successful automatic start. Each of the failures were recovered by operator action, and two of the three events were identified by the ASP Program. The control circuit failures were the result of a failed time delay relay (CCDP of 3.5E-5) and failed contacts for the control switch. Both of these malfunctions prevented the initial automatic start of the pump that were recovered by operator manually starting the pump. The other failure to start was the result of the recirculation valve failing to close once the pump was operating at rated speed. This resulted in a high pump flow rate that caused the pump's circuit breaker to open from high current. This failure was recovered by operators closing the recirculation valve manually and starting the pump (CCDP of 1.0E-5).

4.2.3.3 Maintenance Category. As shown in Table 16, there were five failures assigned to the maintenance-related cause category, and all were classified as failures to start. Of the five failures, three were recovered, one judged as being recoverable, and one was not recovered by operator actions.

Two failures were the result of an incorrect setting of a low-pressure limiter and an amptector. The low-pressure limiter limits pump flow by sensing discharge pressure. As flow rate increases, pump discharge pressure drops, and the limiter acts to prevent excessive pump flow by maintaining a high discharge pressure. The limiter setpoint was too low, which did not limit pump flow rate. The high flow rate required a higher than normal amperage. The pump circuit breaker tripped open on excessive current to prevent pump damage. The pump was restarted and pressure maintained manually. The other failure that was the result of incorrect amptector setpoint caused the pump circuit breaker to open after 2 minutes of operation. This event was identified by the ASP Program and was assigned a CCDP of 2.0E-6. The setpoint of the amptector was such that the breaker tripped at an amperage that is normally experienced during an unplanned demand.

The remaining three failures were the result of mis-wired control circuits. In one instance, two pumps failed to start in manual due to a wiring error in the breaker switchgear. This error was installed 18 months earlier. After the wiring error was discovered, it was found that the motor-driven pump breakers would fail to close with the switches that defeat the automatic start when both main feedwater pumps trip in the AUTO position. This event was also classified as a common cause failure, and was recovered by operator action. The other failure as a result of mis-wired control circuit prevented a single pump from starting in automatic. Operators were able to start the pump manually. The wiring problem was not discovered during the post-maintenance test.

4.2.3.4 Personnel Category. As shown in Table 16, there were two failures classified as resulting from personnel error in the operation of the system. These two failures were classified as an error of commission. This event was the result of the system being disabled by operator action with steam generator levels below the automatic start setpoint. The action was taken to limit plant cooldown. The control switches were left blocked for 19 minutes until a procedure reader noticed the switch position. The failure was recovered after the steam generator levels were restored above the autostart setpoint.

4.2.3.5 Support System Category. As shown in Table 16, there were four failures classified as resulting from a failure of a support system. These events were not used in the unreliability estimate provided previously in Section 3, because they were considered as outside the system boundaries for this study. They are however, included in this discussion because from an operational perspective they are actual instances in which AFW could not respond to a steam generator level transient.

All four of the support system failures prevented the system from starting. Three of the four were the result of the solid state protection system being in test at the time of a demand, and the fourth failure was the result of a loss of control power to the initiation circuit. The cases where the solid state protection system was in test, the automatic start function of the system was blocked; however, operators were able to start the system manually. In the one instance where a loss of control power occurred, the system was prevented from starting in automatic; however, operators were able to start the system manually.

4.2.4 Feed Control Reliability

There were 32 failures of feed control segments. Failures attributed to hardware problems accounted for over 50% of the failures, while maintenance and personnel errors accounted for approximately 12% and 18% of the failures, respectively. Design and environmental-related problems accounted for the few remaining failures.

4.2.4.1 Design Category. As shown in Table 15, there were two failures classified as resulting from a design problem. One failure was the result of the isolation valve to a steam generator closing as a result of high flow. The valve closed because both motor-driven pumps were providing flow to the steam generator. It was later determined that the design setpoint of the high flow isolation was too low. This failure was not recovered. The other failure classified as a design problem resulted from a flow control valve failing to close to limit AFW flow when a motor-driven pump was in a runout condition when steam generator pressure was low. The pump was shut down to prevent damage. Investigation into the cause of the valve failing to close revealed a time delay relay, and two normally open contacts failed to provide a signal to close the valve. The relay was installed during a recent modification, and the circuit was tested successfully during a post-maintenance test. However, the test failed to verify proper operation of the protective function of the valve, which may have revealed that the normally open contacts should have been closed to provide automatic closure during high flow conditions.

4.2.4.2 Environment Category. There were two failures of flow control segments assigned to the environment cause category. These two failures were the result of Asiatic clams entering the system when the suction source was inadvertently switched to a raw water source. This event was previously discussed in the section on common cause failures.

4.2.4.3 Hardware Category. There were 18 failures of feed control segments assigned to the hardware cause category. Four of the instances where feed control valves failed involved two valves failing to control level; of these four, two were classified as common cause failures. The two instances where two valves failed, which were not the result of a common cause failure, were caused by a failed relay that prevented two valves from opening. This type of failure is implicitly modeled in the PRA/IPEs as a single failure causing two valves to fail. The other failure was the result of low flow rates observed to two steam generators. Surveillance testing and pipe internal inspections revealed no problems. However, several months later during an unplanned demand, flow rates were again observed to be low. Subsequent investigation revealed parts of the pumps in the cavitrol cages of the valves. The initial identification of the low flow rates was classified as a failure of the feed control segment, and the subsequent identification of low flow rates and the pump failures were classified as a common cause failure of the pumps.

The 10 remaining feed control segment failures were failures of a single valve to control steam generator level. Of these 10 failures, four were recovered. The types of failures observed in the operational data included valves failing to open because of malfunctioning relays or solenoid operators, switches that sense flow failing causing the valve to close, dirt in the valve positioner, and failed circuit cards.

4.2.4.4 Maintenance Category. There were five failures of flow control segments assigned to the maintenance cause category. These five failures were not recovered. Three of these five failures were independent failures, and the other two resulted from a common cause failure. The three independent failures were the result of the torque switches set too low resulting in the valve failing to throttle closed to limit flow, a loss of automatic control of a valve as a result of a feedback arm that was left disconnected, and a valve stem that mis-adjusted, which necessitated the shutdown of a turbine-driven pump to prevent steam generator overfill. The common cause failure was due to improper torque switch setpoints. The torque switches had been reset several years earlier to improve margin between torque switch trip and thermal overload trip of the motor supply breaker when operating the valve under postulated low-voltage conditions. Also, the adjusted setpoints were based on high flow/high dp. However, the load conditions associated with low flow and high back pressure (i.e., conditions that exist following normal reactor trip) create the highest thrust demand that the motor operator must support. The original torque switch settings which existed earlier would have allowed the valve operator to function properly under the low flow and high back pressure.

4.2.4.5 Personnel Error Category. There were seven failures of flow control segments assigned to the personnel error cause category. Three of these seven failures were the result of the test recirculation line not being fully closed after the completion of a surveillance test. In one event, the test recirculation valve was open, resulting in no flow to a steam generator. The pump flow rate indicated 600 gal/min; however, the steam generator level was not increasing. Operators shut down the motor-driven pump thinking that the pump was not operating and the flow indication was wrong. After shutting down the motor-driven pump, the cross-connect valves from a second motor-driven pump segment were opened.

This also resulted in flow being diverted through the test line. Operators realized that the test return line was open, and closed the valve allowing the recovery of steam generator levels. This event was classified as two segment failures because when the cross-connect valves were opened, two steam generators were not receiving adequate flow. The other failure that related to the test recirculation valve was the result of the valve not being fully closed after a surveillance test. The valve was locked open 3/8th of a turn versus fully closed, which subsequently diverted 100 gal/min of flow from a steam generator. Operators believed that there was a problem with system indication and focused their attention on instrument repairs rather than believing the indications and finding where the flow was being diverted. The recirculation valve was eventually found open and was subsequently closed.

The other four failures occurred during one event and were not recovered. Following unplanned demand (reactor trip), feedwater isolation and auxiliary feedwater actuation occurred. The turbine-driven pump was shut down due to excessive steam and heat buildup in the room below the pump room. The steam buildup was the result of the open casing drain valve on the turbine-driven AFW pump. Three of the four steam generators water levels were above the low-low level, while the remaining steam generator water level was recovering using the two motor-driven pumps. The turbine-driven pump was reset. The steam generator water levels were still fluctuating and while the operator tried to compensate for steam generator water level swings, a second low-low level occurred that caused restart of the turbine-driven pump. Later during the plant restart, steam generator water levels were cycling and resulted in high-high level in one generator and a subsequent feedwater isolation and AFW actuation. The plant was stabilized and then later a second feedwater isolation and AFW actuation occurred due to a high-high water level in a steam generator. This has been a recurring problem associated with steam generator water level control at low power. At the plant at which this event occurred, there is one set of two feed control segments for each motor-driven pump, and one set of four valves for the turbine-driven pump. The failure was classified as a personnel error in operation of the four feed control segments for the two motor-driven pumps.

4.3 Design Class Evaluation

This section provides a review of the failures that contributed to the operational unreliability for each of the 11 AFW design classes. This review primarily focuses on the failures observed during unplanned demands that contributed to the operational unreliability as defined previously in Section 3.2.2. In addition to the design class review, plant-specific reviews of the failures contributing to unreliability are also presented for those plants that have a relatively high operational unreliability as compared to the other plants within the design class. The comparisons within the design classes were based on the data provided previously in Figure 5 in Section 3.2.2.

4.3.1 Design Class 1

The AFW system configuration for Design Class 1 plants consists of one motor-driven and one turbine-driven train supplying two steam generators. Overall, all of the plants assigned to this design class had an operational unreliability slightly higher than the industry average. Two plants within the design class had failures observed during unplanned demands. Two were associated with the turbine-driven pump, and one was associated with the motor-driven pump. All of the failures were classified as failures to start and were not related. Each failure was either recovered or judged to be recoverable. Overall, the high design class unreliability is more than likely the result of the system configuration more than the number of observed failures.

One plant, Crystal River 3, had a higher unreliability than the design class average. Crystal River 3 accounted for two of the observed three failures in this design class. Arkansas Nuclear One Unit 2 accounted for the other. The two failures to start that contributed to the unreliability estimate for Crystal River 3 were observed in the motor- and turbine-driven pump segments and were not related. The motor-driven pump failure to start was the result of a hardware-related failure associated with a time delay relay in the automatic start circuit (CCDP of 3.5E-5). The turbine-driven pump failure to start was the result of water accumulation in the turbine steam supply lines. The one failure at Arkansas Nuclear One Unit 2 was the result of a failed EG-M control box that caused a turbine overspeed trip.

A review of risk-based inspection guides for plants assigned to this class indicated that (in order of importance) common cause failure of multiple pumps, failure of the turbine-driven pump to start or run, motor-driven pump failure to start or run, unavailability due to maintenance, and failure of motor-operated valves were the risk important components and failures modes for two sites. The mechanisms for the failures were reviewed in the inspection guides and compared to the mechanisms of the failures observed in the operational data. The results of the review indicted that the same components and mechanisms for failure were indicated in the inspection guide and observed in the operational data. The only difference was the identification in the inspection guide, of steam binding of pumps as a result of leakage of hot feedwater through several in series check valves while no instance of actual steam binding was observed in the operational data. However, there was one instance at Crystal River 3 in which elevated temperatures were observed in the AFW discharge piping as a result of check valve backleakage. The high-temperature condition was identified quickly by plant operators using installed temperature monitoring equipment, and the piping was flushed to return the temperature to normal conditions.

4.3.2 Design Class 2

The AFW system configuration for Design Class 2 plants consists of one motor-driven and two turbine-driven trains supplying two steam generators. Overall, the two plants assigned to this design class had an operational unreliability lower than the industry average. This design class consists of Calvert Cliffs Units 1 and 2. There were three failures observed during unplanned demands in this design class. All three were associated with the turbine-driven pump. One was a failure to start as a result of trip linkage being out of adjustment, which was recovered (CCDP of 4.8E-4). The second failure was a failure to run caused by a wiped journal bearing, which was not recovered. The remaining failure was a failure to operate of the turbine steam supply as a result of a failed control switch, which was not recovered. (There were no risk-based inspection guides available for review of the plants assigned to this design class.)

4.3.3 Design Class 3

The AFW system configuration for Design Class 3 plants consists of two turbine-driven trains supplying two steam generators. Overall, there is only one plant (Davis-Besse) assigned to this design class, and it had an operational unreliability significantly higher than the industry average. There were no observed failures during unplanned demands at Davis-Besse. However, the plant-specific operational unreliability assigned to this plant is relatively high because of the two turbine-driven pump train configuration of the system. (There were no risk-based inspection guides available for review of the plant assigned to this design class.)

4.3.4 Design Class 4

The AFW system configuration for Design Class 4 plants consists of two motor-driven pump trains and a turbine-driven train supplying two steam generators. Overall, the plants assigned to this design class had an operational unreliability lower than the industry average. There were 10 observed failures during unplanned demands at seven of the 13 plants in the design class. The failures were primarily

(8 of 10) the result of hardware-related problems associated with the motor- and turbine-driven pump and feed control segments. There was one maintenance-out-of-service event and a design related problem associated with motor-driven pumps. (There were no risk-based inspection guides available for review of the plants assigned to this design class.)

For the failures associated with the motor-driven pump segment, there was one observed failure for each of the three failure modes: (1) a design-related problem classified as a failure to run caused by the location of the recirculation line relative to the discharge check valve, (2) a failure to start caused by a hardware-related problem associated with a control switch, and (3) a maintenance-out-of-service. Only the failure of the control switch was recovered by operator action. All of the failures associated with the turbine-driven pump segment were classified as failures to start and resulted in a turbine overspeed trip. The failures were caused by contaminated governor oil and a worn latch mechanism, and the third failure did not contain sufficient information concerning the cause of the trip. Only the overspeed trip that was of an unknown cause was recovered. The failures observed in the feed control segment were all caused by hardware-related problems. Two of the four failures were recovered.

Five plants in the design class had relatively high operational unreliabilities as compared to the other plants in the design class; however, these five plants had operational unreliabilities lower than the industry average operational unreliability. The three Oconee units accounted for four of the 10 observed failures in the design class. These failures were three failures of a feed control segment and a maintenance-out-of-service of the motor-driven pump. The failures of the feed control segments were attributed to hardware-related problems (two failures occurred at Unit 1 and one at Unit 3). Two of the failures were related problems associated with solenoid valves and were identified by the ASP program and assigned CCDPs of 4.0E-6 (Unit 1 failure) and 1.8E-5 (Unit 3 failure). The other feed control segment failure was a result of a failed driver card. Millstone Unit 2 also had a high operational unreliability as compared to the other plants in the design class. There was only one failure observed at Millstone Unit 2—a failure to start of a motor-driven pump as a result of a control switch problem. Three Mile Island Unit 1 had a high operational unreliability as compared to the other plants in the design class; however, there were no observed failures at Three Mile Island. The high operational unreliability is most likely the result of a low number of demands as compared to the other plants in the design class.

4.3.5 Design Class 5

The AFW system configuration for Design Class 5 plants consists of two motor-driven pump trains and a turbine-driven train supplying three steam generators. Overall, the plants assigned to this design class had an operational unreliability significantly lower than the industry average. There were 19 observed failures during unplanned demands at nine of the 12 plants in the design class. The failures were attributed to nine hardware-related problems, five to maintenance, three to personnel error, and two to water accumulation in the turbine steam supply. Nine of the failures occurred as a result of a common cause failure mechanism.

There were eight failures associated with the motor-driven pump segment; six of the eight were related to a common cause failure mechanism. Three failures were classified as failures to start, four failures were classified as failures to run, and one was a maintenance-out-of-service event. The four failures to run were caused by an error of commission (recovered) and a failure of the pump channel ring vanes, and the failures to start were all caused by mis-wired control switches. One of the failures to start and the maintenance-out-of-service event were recovered by operator actions. Five of the failures associated with the turbine-driven pump segment were classified as failures to start, two were failures to run, and there was one maintenance-out-of-service. The failures to run were caused by a personnel error (error of commission that was recovered) and a plug blowing out of the trip limiter and striking the trip linkage that was not recovered. There were three failures observed in the feed control segment, and all were caused by hardware-related problems that were not recovered.

Three plants in the design class had relatively high operational unreliabilities as compared to the other plants in the design class; however, these plants had operational unreliabilities lower than the industry average operational unreliability. Beaver Valley Unit 2 had a relatively high operational unreliability as compared to the other plants in the design class. The high operational unreliability was attributed to two failures: a failure to start associated with the turbine-driven pump and a failure to operate of a feed control segment. Both of the failures were hardware related that were not recovered. North Anna Units 1 and 2 also had relatively high operational unreliabilities as compared to the other plants in the design class. The high operational unreliability at these two plants is attributed to a turbine-driven pump failure to run as a result of a blown plug in the trip limiter (CCDP 1.1E-6).

A review of risk-based inspection guides for the Design Class 5 plants indicated that (in order of importance) common cause failure of multiple pumps, failure of the turbine-driven pump to start or run, motor-driven pump failure to start or run, unavailability due to maintenance, and failure of motor-operated valves were the risk important components and failures modes for identified sites. The mechanisms for the failures were reviewed in the inspection guides and compared to the mechanisms of the failures observed in the operational data. The results of the review indicted that the same components and mechanisms for motor-and turbine-driven pump failures were indicated in the inspection guide and observed in the operational data. The inspection guides indicated failures of flow control, and pump suction and discharge valves were significant contributors to AFW risk. However, these failures were not significant contributors in the operational data selected for this study for this design class. Also, the identification of steam binding of pumps as a result of leakage of hot feedwater through several in series check valves was identified in the inspection guides as a significant contributor to AFW risk; however, no instance of actual steam binding was observed in the operational data for the design class.

4.3.6 Design Class 6

The AFW system configuration for Design Class 6 plants consists of only three turbine-driven trains supplying three steam generators. Turkey Point Units comprise this design class. Overall, there were only two maintenance-out-of-service events observed in this design class that contributed to the operational unreliability estimate (CCDPs of 3.7E-6 and 3.1E-6). There were no other observed failures during unplanned demands at these two plants. However, the plant-specific operational unreliability assigned to these plant is relatively high because of the three turbine-driven pump train configuration of the system. (There were no risk-based inspection guides available for review of the plants assigned to this design class.)

4.3.7 Design Class 7

The AFW system configuration for Design Class 7 plants consists of only one motor-driven train and a diesel-driven pump train supplying four steam generators. The Byron and Braidwood Units comprise this design class. The plant-specific operational unreliabilities assigned to these plants was below the industry average unreliability, and no one plant accounted for a majority of the failures. Overall, there was only five failures observed in this design class. Two failures were the result of support system failures that were not used in the unreliability analysis. The other three failures were hardware-related problems classified as a failure to start and a failure to run associated with the diesel-driven pump train, and a failure to operate of a feed control segment. With the exception of the failure to run of the diesel-driven pump segment, the failures were recovered by operator action. The failure to start of the diesel-driven pump was also identified by the ASP Program and was assigned a CCDP of 4.0E-5. (There were no risk-based inspection guides available for review of the plants assigned to this design class.)

4.3.8 Design Class 8

The AFW system configuration for Design Class 8 plants consists of a turbine-driven train and motor-driven train supplying four steam generators. Seabrook is the only plant that comprises this design class. Overall, there was only one failure to operate of a feed control segment as a result of a design problem. The isolation valve to the "A" steam generator closed as a result of a high flow condition caused by running both pumps. There were no other observed failures during unplanned demands at this plant. However, the plant-specific operational unreliability assigned to this plant is relatively high as compared to the other design classes because of the two pump train configuration of the system. (There were no risk-based inspection guides available for review of the plants assigned to this design class.)

4.3.9 Design Class 9

The AFW system configuration for Design Class 9 plants consists of two turbine-driven trains supplying four steam generators. Haddam Neck is the only plant that comprises this design class. Overall, there were no observed failures during unplanned demands at this plant. However, the plant-specific operational unreliability assigned to this plant is relatively high as compared to the other design classes because of the system configuration, and the relatively few number of unplanned demands observed at the plant during the study period. (There were no risk-based inspection guides available for review of the plants assigned to this design class.)

4.3.10 Design Class 10

The AFW system configuration for Design Class 10 plants consists of two motor-driven pump trains and a turbine-driven train supplying four steam generators. Overall, the plants assigned to this design class had an operational unreliability lower than the industry average. There were 39 observed failures during unplanned demands at 12 of the 23 plants in the design class. The failures were primarily the result of hardware (14 of 39) and maintenance (11 of 39) related problems. Personnel error in operation of the system, environment, and design-related problems accounted for the remaining failures. There were five maintenance-out-of-service events observed in the design class: three were associated with the motor-driven pumps and two with the turbine-driven pumps.

For the failures associated with the motor-driven pump segment, there were five failures to start and three maintenance-out-of-service events. Four of the five failures to start were recovered by operator action. The failures to start were the result of a design-related common cause failure, two maintenance-related problems, and a hardware failure. The design-related common cause failure was the result of the low-pressure shutdown switches being set at too high a pressure. The maintenance-related problems were the result of the incorrect settings of a breaker high current trip (the failure was not recovered) and a flow limiter. The one hardware-related problem was the result of a failed flow controller, which prevented the recirculation valve from closing, causing a pump high flow condition.

For the failures associated with the turbine-driven pump segment, there were five failures to start, one failure to run, and two maintenance-out-of-service events. Four of the five failures to start were recovered by operator action. The failures to start were the result of three hardware-related problems, a maintenance related problem, and a personnel error. The hardware-related problems were the result of (1) an electronic overspeed that was recoverable, (2) contaminated governor hydraulic oil that caused an overspeed trip that was not recovered, and (3) a corroded trip linkage that caused an overspeed trip that was not recovered. The maintenance-related problem was the result of the incorrect travel adjustment of the trip linkage that caused an overspeed trip that was not recovered. The one personnel error was the result of leaving the turbine casing drain valve open, filling the turbine room with steam. The personnel error was recovered. The one failure to run event was the result of the governor not being able to control turbine speed with varying steam pressures. The failure to run was not recovered.

For the failures associated with the feed control segments, no one cause clearly dominated the failures. The causes of the failures were distributed between hardware related problems (8), environmental problems (6), maintenance errors (4), personnel error (4), and a design problem (1). Recovery from the feed control segment failures was only observed in the events attributed to hardware (seven of eight were recovered). There was no recovery from the environmental, personnel error, and maintenance-related failures.

There were six plants that had relatively high operational unreliabilities as compared to the other plants in the design class. However, these operational unreliabilities were lower than the industry average operational unreliability. Wolf Creek had the highest operational unreliability in the design class. This operational unreliability was attributed to a turbine-driven pump failure to start as a result of leaving the casing drain valve open, and failure to maintain steam generator level with only the motor-driven pumps. Indian Point Unit 2 had an operational unreliability that was relatively high as compared to the other plants in the design class. This operational unreliability was attributed to a common cause failure of the motor-driven pumps as a result of the design setpoint of the pump low-pressure shutdown switch (CCDP of 3.6E-6), and a failure to start caused by a maintenance error in the setpoint of a motor-driven pump's circuit breaker over-current protection (CCDP of 2.0E-6). Indian Point Unit 3 also experienced a high operational unreliability in the design class. This operational unreliability was attributed to two failures to start of motor-driven pumps. One failure was a result of the incorrect setpoint of a flow limiter, and the other was the result of a failed open recirculation valve (CCDP of 1.0E-5). Both of these failures resulted in a pump high flow conditions. Cook Unit 1 had an operational unreliability that was relatively high as compared to the other plants in the design class. This operational unreliability was attributed to a maintenance-related problem associated feed control segment. The torque switches were set improperly, resulting in the valve failing in the open position, causing a high flow condition. Millstone Unit 3 had an operational unreliability that was relatively high as compared to the other plants in the design class. This operational unreliability was attributed to a hardware-related problem associated with the feed control segment. The control switch malfunctioned, failing the valve in the "as is' position. In addition, Millstone Unit 3 experienced two maintenance-out-of-service events associated with a turbine- and motor-driven pump. The remaining plant that had an operational unreliability that was relatively high as compared to the other plants in the design class was Sequoyah Unit 1. This operational unreliability was attributed to a maintenance-related problem associated with the feed control segment. The failure was the result of not reconnecting the feedback arm, thereby preventing the valve from controlling level.

A review of risk-based inspection guides for the Design Class 10 plants indicated that (in order of importance) common cause failure of multiple pumps, failure of the turbine-driven pump to start or run, motor-driven pump failure to start or run, unavailability due to maintenance, and failure of motor-operated valves were the risk important components and failures modes for identified sites. The mechanisms for the failures were reviewed in the inspection guides and compared to the mechanisms of the failures observed in the operational data. The results of the review indicted that the same components and mechanisms for motor-and turbine-driven pump failures were indicated in the inspection guide and observed in the operational data. The inspection guides indicated failure of flow control, and pump suction and discharge valves closed were a significant contributor to AFW risk. The operational data also indicted that failure of these valves was a significant contributor to risk. However, approximately 30% of the failures were the result of the valve failing open. In three instances, operators shut down operating pumps to prevent pump damage because of the failed open valves. The inspection guides also identified steam binding of pumps as a result of leakage of hot feedwater through several in series check valves as a contributor to risk; however, no instances of steam binding were observed in the design class.

4.3.11 Design Class 11

The AFW system configuration for Design Class 11 plants consists of one turbine-driven train and three motor-driven trains with each train supplying one of four steam generators. This design class is comprised of the two South Texas plants. Overall, there were three observed failures during unplanned demands at these two plants. Each of the three failures was the result of personnel error in operation of the system. Two failures were associated with the feed control segment and the other the turbine-driven pump. The plant-specific operational unreliability assigned to Unit 1 is relatively high as compared to the other design classes. However, the plant-specific operational unreliability assigned to Unit 2 is relatively low as compared to the other design classes. The difference is owing to the two feed control segment failures that were observed at Unit 1. (There were no risk-based inspection guides available for review of the plants assigned to this design class.)

The failures observed at South Texas Unit 1 were both feed control segment failures as a result of personnel error in operation of the segment. The first failure was the result of not fully closing the test return isolation valve after the performance of a surveillance test. As a result of the open test return valve, when the system was demanded, flow was diverted from the steam generator to the test return line, preventing recovery of steam generator level. The other failure at Unit 1 was the result of cross-connecting a second feed control segment to the segment with the open test return isolation valve, resulting in diverting flow from two steam generators to the test return line. The one observed failure at Unit 2 was also the result of personnel error. The failure was the result of shutting down the turbine-driven pump to limit plant cooldown. However, no other means of providing feedwater were available to the steam generator. At South Texas, even though there are four AFW trains, each train supplies one steam generator with the capability of cross-connecting the individual trains. Normally, the cross-connect valves are closed. When any train is shut down, either normal feedwater must be available or the cross-connect valves open to ensure adequate feedwater to the steam generator. In the instance where the turbine-driven pump was shut down to limit cooldown rate, the turbine-driven pump restarted automatically because of a low-level condition in the steam generator that occurred a few minutes later. From the information provided in the LER, there was no feedwater flow from any source to the steam generator after the turbine-driven pump was shut down.

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Appendix A

AFW Data Collection and Analysis Methods

Appendix A

AFW Data Collection and Analysis Methods

To characterize auxiliary feedwater (AFW) system performance, operational data pertaining to the AFW system from 72 U.S. commercial nuclear pressurized water reactor plants having AFW systems were collected and reviewed. This appendix provides descriptions for the operational data collection and the subsequent data characterization for the estimation of AFW system unreliability. Unreliability is considered for two sets of accident/transient responses. Both of these deal with AFW's safety system function, namely providing adequate flow to the steam generator(s) in response to a low steam generator(s) water level. The first pertains to *operational unreliability* (i.e., the type of mission that AFW is typically required to meet in actual plant operations). Study of this mission shows the strengths and weaknesses of the AFW system in its ordinary operation (i.e., the conditions encountered most often during plant transients requiring the AFW system). Typically, these transients require AFW to automatically start and deliver feedwater to one or more steam generators as required. These missions are generally of short duration. The second response deals with the *risk-based unreliability* of the AFW system. Here, the system requirement is required to run for an assumed mission time of from 4 to 24 hours.

For both of these analyses, 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 AFW system for the plants used in this study differs considerably between the plants. The plants have different numbers of trains and types of pump drivers, along with initiation 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 11 different AFW design classes.

To estimate unreliability for each AFW 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 AFW demands and associate the failures with the demands consistently within each group and where possible for the industry, the AFW system was partitioned into segments to facilitate the subsequent analysis. These system segments are (1) suction, (2) turbine-driven pump, (3) turbine steam supply, (4) turbine-driven pump feed control, (5) electric-motor-driven pump, (6) electric-motor-driven pump feed control, (7) diesel-driven pump, (8) diesel-driven pump feed control, (9) common feed control, (10) steam generator feed, and (11) instrumentation and control. The composition of the various components for each segment may differ among plants within an AFW 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 AFW 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 suction segment (CST-SUCT) includes all piping and valves (including valve operators) from the feedwater source to the pump suction isolation. It includes two piping lines for some plants, but was treated as a single segment since no common cause failures were seen in the LER data.

2. The turbine-driven pump segment (TDP-*ff*, where *ff* describes a failure mode) includes the turbine, trip and throttle valve, governor assembly with the associated controls, the turbine steam supply isolation just upstream of the trip throttle valve, and the valve operators. Also included with this segment is the pump and associated piping from and including the suction isolation 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.

3. The turbine steam supply segment (TD-STM-SUP) includes the associated piping, valves, and valve operators from the main steam line penetrations to the turbine steam supply isolation valve. The instrument air supply and dc power to the solenoid-operated valves were excluded.

4. The turbine-driven pump feed control segment (TDP-SG*x*-SEG, where *x* is a particular steam generator identifier) includes the piping and valves from the pump discharge isolation up to the steam generator for plants with only one AFW injection header per steam generator or plants where AFW has no connection with the main feedwater system. For plants with more than one injection header per steam generator or AFW connects with the main feedwater system, the turbine-driven pump feed control segment includes the pump discharge isolation valve and upstream piping up to the connection point for the alternate injection path or main feedwater system. Included with the segment are the associated valves and valve operators, the flow control valve and the control logic, and the test recirculation line if applicable.

5. The electric-motor-driven pump segment (MDP-*ff*) includes the 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 valves 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.

6. The electric-motor-driven pump feed control segment (MDP-SG*x*-SEG) includes the piping and valves from the pump discharge isolation up to the steam generator for plants with only one AFW injection header per steam generator or plants where AFW has no connection with the main feedwater system. For plants with more than one injection header per steam generator or AFW connects with the main feedwater system, the electric-motor driven pump feed control segment includes the pump discharge isolation valve and upstream piping up to the connection point for the alternate injection path or main feedwater system. Included with the segment are the associated valves and valve operators, the flow control valve and the control logic, and the test recirculation line if applicable.

7. The diesel-driven pump segment (DD-*ff*) includes the diesel engine, the associated fuel oil including the day tank, the cooling water up to the supply isolation, and the governor and the engine starting system. Also included with this segment is the pump and associated piping from and including the suction isolation 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.

8. The diesel-driven pump feed control segment (DD-SG*x*-SEG) includes the piping and valves from the pump discharge isolation up to the steam generator for plants with only one AFW injection header per steam generator or plants where AFW has no connection with the main

feedwater system. For plants with more than one injection header per steam generator or AFW connects with the main feedwater system, the diesel-driven pump feed control segment includes the pump discharge isolation valve and upstream piping up to the connection point for the alternate injection path or main feedwater system. Included with the segment are the associated valves and valve operators, the flow control valve and the control logic, and the test recirculation line if applicable.

9. The common feed control segment (PMP-SG*x*-SEG or MTDP-SG*x*-SEG) applies to plants where the turbine/diesel and electric-motor-driven pumps discharge to a shared header with flow to the steam generator being regulated in the common header. This segment includes the piping and valves from (not including) the pump discharge isolation up to the steam generator for plants with only one AFW injection header per steam generator or plants where AFW has no connection with the main feedwater system. For plants with more than one injection header per steam generator or AFW connects with the main feedwater system, the feed control segment includes the pump discharge isolation valve and upstream piping up to the connection point for the alternate injection path or main feedwater system. Included with the segment are the associated valves and valve operators, the flow control valve and the control logic, and the test recirculation line if applicable.

10. The steam generator feed segment (CKV-SG*x*) includes the check valve(s) and associated piping downstream of the common or turbine/motor feed segments. Generally, this segment includes the last set of check valves in the feedwater system piping that prevent diverting AFW flow from the steam generator.

11. The instrumentation and control segment includes the circuits for the system initiation and operation. However, each of the component failures in these circuits were screened to ensure that the component failure identified in the circuit was dedicated to the AFW system. Note that all failures associated with segment occurred by observation or in surveillance tests; none occurred in the LER unplanned demands. Therefore, this segment was not included in the PRA models.

Each plant's AFW system has several but not all of these 11 segment types. Appendix D provides block diagrams of typical configurations of these segments for each of the 11 identified AFW design classes. Also, plant and class-specific fault trees were developed to describe how the AFW fails in terms of these segment types.

A-2. DATA COLLECTION AND CHARACTERIZATION

The AFW 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 AFW system for the years 1987 through 1995. To ensure as complete a data set as possible, the SCSS database was also searched for all safety injection actuations and critical reactor trips for plants that have an AFW system. These records potentially provide an additional source of AFW actuations because (1) the AFW system is typically demanded as a result of a safety injection demand and (2) AFW may be required to start following a reactor trip as a result of either steam generator level shrink or feedwater problems experienced as part of the trip.

Differences may exist among plants interpreting what is an AFW ESF actuation or failure and hence what is reportable. 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 AFW 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] (AFW ESF actuations were found and reported as ESF actuations for all plants in the study.) AFW 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 AFW.

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 AFW failures during various plant operating conditions and testing. In this report, the term *inoperability* is used to describe any AFW 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 for the operational and/or the risk-based missions.

The AFW 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 AFW 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, an electric-motor-driven 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. 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, with care taken 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 AFW failures, failure modes, failure mechanisms, causes, etc. were based on the independent review of the information provided in the LERs.

Three 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 that were 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.

Failure classification of the events for a risk-based mission was based on the ability of the AFW system to function as designed for up to 24-hours. Inoperability events classified as failures for an operational mission were based on successful operation while the system was needed. Thus, events could be classified as failures for a risk-based mission even if the system functioned successfully for the operational mission. Therefore, these events would be included in the failure count for a risk-based mission, but would not be included in the failure count for an operational mission. An example of such a failure would be a turbine governor oil leak that would allow the turbine to operate while it was needed to restore steam generator level (15 minutes). However, the oil leak would fail the turbine, and hence the pump, in a longer 24 hour risk-based mission. Each LER was reviewed to determine if the segment would have been reasonably capable of performing its safety function for each mission.

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 AFW system to complete its mission. Specifically, an electric-motor-driven pump segment may have failed to start; however, the turbine-driven and/or redundant electric-motor-driven 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 a low steam generator water level condition to preclude level restoration.

- The flow control valve does not modulate closed to prevent a pump runout condition as required following an automatic system initiation with a low steam generator pressure.

- The turbine-driven pump trip/throttle valve is blocked closed for pre-planned maintenance associated with the turbine when a low-low water level condition occurs in two or more steam generators.

- One of the two steam supply valves to the turbine-driven pump fails to open when the turbine-driven pump is demanded during a low-low water level condition in two steam generators.

- A pump is shut down by operator action for any reason with steam generator level at or below the initiation setpoint.

- The flow controller malfunctions and either prevents the system from providing the required flow to any steam generator, or requires an operator to place the controller in manual because of erratic operation.

- Water in the turbine steam supply line causes the turbine to overspeed and trip during an unplanned start attempt.

- The turbine-driven pump is shut down by operator action as a result of a steam leak associated with the turbine steam supply.

- Sludge or foreign material in the pump casing results in a reduction in pump capacity.

- A damaged pump impeller as a result of stress corrosion cracking.

- Personnel error in operation of the flow controller that causes the turbine to trip, or results in a low-low water level condition in a steam generator.

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 (diesel, turbine, and electric motor). Examples of the types of events classified as MOOS include an electric-driven pump motor's circuit breaker being racked out for repairs, or the turbine-driven pump steam supply valves being closed with the control switch marked-up/tagged in the closed position to allow maintenance on the turbine governor.

- Failure to start (FTS) occurred if the pump segment was in service but fails to automatically start or manually start, and obtain sufficient condensate pressure and flow. This failure mode applied only to the pump segments (diesel, turbine, and electric motor). 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 turbine trips on overspeed as a result of water accumulation in the steam supply lines, erratic operation of the turbine governor that required the turbine to be shut down before the required flows and pressures are observed, a damaged pump impeller, and an electric-driven pump motor's circuit breaker fails 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. As an example, if the turbine casing drain valve was inadvertently left open, resulting in filling the turbine-driven pump room full of steam necessitating a turbine shutdown, the event was classified as a failure to start even though the turbine may have ran for a few minutes prior to the shutdown. Also, a failure may have been classified as a failure to start if the electric-driven pump circuit breaker tripped on over-current a few minutes after a successfully 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 start was also used in the observed and surveillance test data for losses of the safety function of the instrumentation segment. These failures do not affect the unreliability analysis, however, since none occurred during the unplanned demands.

- Failure to run (FTR) occurred if, at any time after the pump segment was delivering sufficient condensate pressure and flow, the segment failed to maintain sufficient pressure and flow while it is needed due to a time dependent mechanism not present at the time of the demand. This failure mode applied only to the pump segments (diesel, turbine, and electric motor). 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 turbine overspeeds and trips as a result of a failed resistor in the governor speed control circuit, erratic operation of the turbine governor that required the turbine to be shut down at anytime after the required flows and pressures are observed, insufficient pump packing lubrication that causes the packing to overheat and subsequently fail the pump, the pump recirculation line fails to provide adequate pump overheating protection, and an electric-driven pump motor’s circuit breaker opens as a result of excessive current flow.

- 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 erratic operation of the flow control valves, one of the two turbine steam supply valves fails to open on demand, a flow control valve opens too far resulting in steam generator over-fill concern, a flow control valve closes too much requiring operator action to control steam generator level, and a test return valve is left partially open after a surveillance test resulting in degraded flow to a steam generator.

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: the low suction pressure shutdown switches are set at too high a pressure resulting in a failure of both motor-driven pumps to start when demanded, the control circuit for two flow control valves were reverse-wired during a previous maintenance activity resulting in the operation of the switch for valve ‘A’ causing valve ‘B’ to re-position, and a motor-driven pump exhibits degraded flow during a surveillance test that is determined to be a result of stress corrosion cracking, which is also found affecting the turbine-driven pump.

- Error of commission (EOC) occurred if the AFW system was rendered inoperable by operator action when the system was needed to restore steam generator level. An example is operators placing the control switches for the pumps in pull-to-lock with steam generator levels below the automatic start setpoint.

For the events associated with the feed control segments, some LERs identified a degraded flow condition to one or more steam generators. 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 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 a feed control 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 feed control 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 feed control segment was classified as failed.

Some of the LERs identified feed control valves that failed in the open position, while failure of a valve in the open position could be considered a “fail-safe” position, these malfunctions of the flow control valves were classified as failures of the feed control segment to operate. This classification was based on the need for the feed control 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. As an example, if a feed control valve failed open for a motor-driven pump, the pump would fill the steam generator to the steam lines and subsequently fail the turbine-driven pump. The turbine-driven pump failure would occur through actuation of the high steam generator water level trip that closes the trip-throttle valve. In addition, water would still enter the turbine steam supply piping, and during any subsequent restart of the turbine it would overspeed as a result of the water accumulation. As a result of the impact on the turbine-driven pump, the feed control segment was classified as failed.

A second rational for classifying a failed open feed control valve as a failure of the feed control segment stems from the shutdown of the motor-driven pump by the control room operator prior to reaching a high level condition (Same example as stated in the previous paragraph). If the motor-driven pump is shutdown, the shutdown of the motor-driven pump effectively fails the motor-driven pump segment for the remainder of the operational or risk-based mission. This is because continued heat removal through the atmospheric dump valves would not end once the generator level is initially restored above the autostart setpoint. Steam would continue to be bled from the steam generator lowering the level to the autostart setpoint. The pump would restart with a wide open valve drawing an unusually high starting current (normal starting current is five times running current with a discharge closed) which could damage the motor windings. Given that the pump would have to be restart many times over a 24-hour period for a risk-mission, damage to the motor windings would be inevitable. In addition for an operational mission, as the cooldown continues steam generator pressure would lower. As the downstream pressure of the pump lowers, flow rates would increase. This could result in excessive pump flow rates and possibly a pump runout condition if flow is greater than design flow. The excessive flow that could occur from the reduced steam generator pressure would cause motor amps to increase and this high amperage could cause the motor circuit breaker to open or possible damage to the motor windings.

Overall, while a failed open flow control valve could be considered a “fail safe” position, this “fail safe” designation does not take into account long-term operation of the segment for either an operational or risk-mission. In either of these missions, a pump segment would have to be shutdown because of the failed open valve. While is possible to successfully operate the segment with a failed open valve by throttling a pump discharge isolation, this action is considered a recovery action for the segment and not a normal successful operation of the segment.

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 turbine-driven pump tripped on overspeed (electric) and (b) manually resetting the electric-overspeed trip from the control room, thereby causing the turbine to restart. 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 the turbine-driven pump overspeed on a startup and both motor-driven pumps were operating properly, operators would not normally pursue recovery of the turbine-driven pump segment. 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 a turbine-driven pump tripping on overspeed, engineers assessed whether, given the information in the LER, the likelihood was high that the operators would have been able to reset the overspeed trip and start the turbine if necessary. If the overspeed trip was an electrical overspeed, this failure was typically judged to be recoverable because most electrical overspeed trips are easily reset. However, if the overspeed trip was a mechanical overspeed trip resulting from a broken linkage, 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 (unplanned demand, surveillance test, engineering design review, or other routine plant operations)
- The cause of the event (e.g., design, hardware, maintenance, personnel, procedure, support system, water accumulation, 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 undersized fuses, improper relays for the circuit operation, torque switches for motor-operated valves set too low/high, and high energy line break and seismic qualification errors.

- *Hardware*—Inoperabilities that were the result of components failing to satisfactorily perform their 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. This category primarily included actual failures. Examples of the types of inoperabilities that were assigned to the "Hardware" category include blown fuses that were the proper size, worn packing that prevents proper operation of valves or pumps, worn pump impeller wearing rings, turbine overspeed trips as a result of governor binding or a worn linkage, 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. This category primarily included actual failures that manifested themselves during an unplanned demand. Examples of the types of inoperabilities that were assigned to the "Maintenance" category include torque switches set too low resulting in a motor-operated valve failing to open when demanded, improper oil or lubricant used in motor bearings or gear boxes, control switches wired incorrectly, incorrect assembly of the turbine-driven pump governor, test recirculation valves left in the open position after the test, switches left in the test position after the test, and removing the channel 'A' fuses when it was intended to remove the channel 'B' fuses.

- *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, blocking any system automatic start function when required to be operational by plant technical specifications, and operation of the flow control valves that results in additional low steam generator levels or trips operating pumps because of overfeeding a steam generator.

- *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 torque switch settings for a motor-operated valve being too low because the values listed in the procedure were incorrect, or the control switches for the discharge valves of a pump being left in the closed position versus open permissively because the step that requires the repositioning of the switch was inadvertently omitted in a procedure revision.

- *Environment*—Inoperabilities that were the result of an intrusion of clams, shells, or sludge were classified as "Environment." The failures assigned this cause category may have a root cause related to one or more of the previously mentioned categories. However, because of the number of instances observed in the operational data for which sludge or the presence of clams cause degraded flow during pump operation, this cause category was created to track these specific events.

- *Support system*—AFW segment inoperabilities that were the result of a failure mechanism associated with a system outside of AFW but necessary for the operation of AFW 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 AFW could not respond to a low level in a steam generator. Therefore a review of these events is provided in the Engineering Section of the report for informational purposes only. The types of failures caused by support system failures include AFW inoperabilities from losses of 4,160-Vac control power and from ESF actuation system failures.

- *Water accumulation*—Inoperabilities that were the result of water in the turbine casing or turbine steam supply lines that resulted in a turbine overspeed trip when demanded or caused components to be damaged were classified as "Water accumulation." The failures assigned this cause category may have a root cause related to one or more of the previously mentioned categories. However, because of the number of instances observed in the operational data for which water accumulation either caused or directly contributed to a turbine overspeed trip on an unplanned demand, 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 AFW segment would have been able to perform as required even though it was not operable as defined by plant technical specifications. As an example, 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. However, the results of an engineering analysis for the missing restraint provided by the plant in the safety analysis section of the LER indicated that the existing system configuration would not fail given a seismic event. Based on the engineering analysis information provided by plant personnel in the LER, the event would not be classified as a failure. Other inoperabilities **not** classified as failures include configuration errors associated with the floor drain system, missing or inadequate high energy line break provisions, and valves failed in the position required for emergency response.

In addition, administrative problems associated with AFW 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 because the segment would still be capable of functioning as designed given a demand for the segment. Moreover, plant personnel typically would state in the LER that the segment was available to respond and that the subsequent surveillance test was performed satisfactorily. 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 AFW 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 AFW 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 under-voltage relays in the emergency power system set at the wrong voltage, a de-energized emergency bus that prevented the start of an electric-driven pump, malfunction of protective/actuation circuitry that is not specifically dedicated to the AFW 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 “A” electric-motor-driven AFW system 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 AFW 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 AFW 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 AFW 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.

Two sets of AFW system responses were considered in this study: responses for the operational mission, and responses for the risk-based mission. By definition, the unplanned demands are instances of AFW response showing its *operational unreliability* (i.e., the type of mission that AFW is typically required to meet in actual plant operations). Study of this mission shows the strengths and weaknesses of the AFW system in its ordinary operation (i.e., the conditions encountered most often). Sustained operation for periods of 4 to 24 hours is required for the risk-based mission.

As explained in further detail below, the unplanned demands meet the countable and rigorous requirements, but 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. Unplanned demands usually were the result of actual low steam generator water level conditions, safety injection demands, or losses of normal feedwater (main feedwater pump trips or low main feedwater header pressure). Other plant conditions may have also resulted in an unplanned demand of AFW based on the plant-specific design of the AFW initiation circuit. These initiations of AFW were also included in the study if they resulted from a valid signal. All valid signals occurred when the plant was operational.

Spurious signals or those inadvertent initiation signals that occurred during the performance of a surveillance test were not classified as demands. For example, shorting test leads or blown fuses that resulted in a demand signal were not counted as a valid demand of AFW's safety-related function.

The LERs identified from the SCSS database search were reviewed to determine the nature and frequency of AFW 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 AFW 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 AFW. For example, an LER might state that a low-low water level condition existed in two steam generators during the event. Based on the information provided in the FSAR for the particular plant, the condition would result in the automatic start of both electric-motor-driven pumps and the turbine-driven pump, and result in AFW flow to the steam generators. However, no explicit identification of the AFW pump start may have been found in the LER. In another example, an LER may describe that a low water level condition existed and the motor-driven pumps started. However, based on the information provided in the FSAR for the particular plant, the pumps would run in a recirculation mode and no AFW flow would be provided to the steam generators until water level dropped to an even lower level.

As a result of the reviewing the full text of each LER and plant-specific knowledge concerning AFW initiation and operation, it was possible to determine a relatively accurate number of AFW unplanned demands throughout the industry, even though not every demand was explicitly identified in the LERs. Therefore, the number of events classified and used in this study to determine the number of AFW unplanned demands will differ from the number of ESF actuations identified in a simple SCSS database search. This difference results from the differing coding methodology employed in coding an event for SCSS and for analysis in this study. Specifically, SCSS will only capture explicitly identified AFW ESF actuations, while in this study the intent was to capture all actual AFW 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 based on a review of the system operating characteristics and initiation parameters.

The review of the unplanned demands also included capturing in the database the average pump run times specified in the LER for each type of pump that received a demand to start and run during the events.

A few of the valid unplanned demands occurred during startup sequences, when the AFW system was being used for ordinary feedwater control. New demands to start and run were not counted for the one or more AFW pump trains already running. The control segments, however, were used in these events in response to the steam generator level control requirements of the unplanned demand.

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

A-2.2.2 Surveillance Tests

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, the quarterly surveillance tests of the pumps that are required to be performed per ASME Section XI could also be used to estimate reliability. Because both of these tests are performed at a relatively standard frequency and place approximately the same stresses on the system as an actual plant transient, they could be used to estimate a demand frequency and subsequent reliability estimate of the system for a risk-based mission. However, reasonable assurance must exist that all failures associated with these 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.

A-2.2.3 Pump Run Times

For the risk-based mission unreliability calculations, rates were used to quantify probabilities for failure to run for the required mission time specified in each plant’s IPE study. For these calculations, the run times for each type of pump stated in the LERs were used to normalize the failure counts. Many of the run times, however, were unknown. For each type of pump, two average run times were computed from the unplanned demand LERs for which run times were specified. One run time was derived from those events with run times for which AFW system failures were observed. A second average was derived using those events for which no failures were observed. 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. Where an actual run time occurred, one of the two calculated average run times for the type of pump was applied. The choice of the average run time was based on whether a failure (any failure) occurred from the unplanned demand. No statistical tests were performed to identify actual differences in the run time reporting among events with and without failure. The run time estimates were separated for events with and without failure in order to avoid any possible bias that might come from events with failures being truncated, or from a greater percentage of reporting of actual run times among events with failures.

Using projected run times based on averages of known times for unknown run times introduces additional uncertainty in the failure rate estimates, which 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 AFW 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, as were outages lasting more than 2 days.

To evaluate trends with respect to plant age, it was assumed that the age of the AFW system is the same as the total calendar time of the plant from the low-power license date. Each plant's AFW 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.

A-3. ESTIMATION OF UNRELIABILITY

Four groups of estimates were evaluated for the AFW 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 AFW system. The total failure probabilities were developed for use with common cause *alpha* factors, discussed elsewhere in this report, to quantify the common cause portion of the fault trees. Common cause probabilities for failure of more than one segment in an event were estimated directly from the LER data for comparison with the results of the alpha factor methodology (see Section E-2).

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 the risk-based model for failure to run for the three pump types. For FTR, most of the operational demands were relatively short compared with the 4 to 24-hour mission times 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 AFW system. Failure probabilities were quantified for each of the types of segments described in Section A-1, except for instrumentation (no instrumentation segment failures occurred in the unplanned demands). 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, except for the suction segment, which was defined such that each AFW system has exactly one.

Recovery modes were modeled for failure modes having at least one failure and for which recovery was possible. MOOS is included in the recovery mode assessments because restoration of AFW trains declared out of service for maintenance occurred in several AFW events. 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, including the observed and test data, CCF was quantified for FTS for motor trains, for FTR across train types, for FTO for the feed control segments, and for FTO of the steam feed supply into the turbine-driven pumps. Since the driver types differ, the FTR evaluation across train types was based on only pump-related failures. For these four CCF failure-modes, four 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. Recovery was considered for all of these estimates except for the steam feed supply, for which no CCFs occurred among the unplanned demands. In the fault trees, the recovered total failure estimates (or recovered total failure estimates, as applicable) were in AND gates with factors reflecting the fractions of common cause events with sufficient loss to defeat the success criteria of the system.

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 AFW system during the 1987–1995 study period and included partial as well as total losses of function. For failure of the motor-driven pumps to start, both the pump and the associated motor were considered. The FTR data came solely from AFW pump failures, without regard to the driver type. Data for both air-operated and motor-operated valves were considered for the feed control segments. For the turbine steam supply, air-operated steam line valves were considered.

Simple counts of failures involving more than one like segment, and of the opportunities among the unplanned demands for such failures, were used to estimate the CCF probabilities from the LERs. These estimates are expected to have a much greater uncertainty than the alpha factor method. They were developed for comparison of the two methods (see Section E-2).

The independent and total failure probability and rate estimates were in several instances estimated separately for the operational model and the risk-based model. This separation occurred whenever events occurred for which AFW segments met the requirements of the operational mission but were degraded. For these events, the engineering judgment was that they would not have functioned for the longer time periods associated with a risk-based mission.

A final type of estimate developed for consideration in the AFW unreliability analysis was the impact of errors of commission by AFW operators that rendered one or more trains of AFW unavailable during certain events. The operators, attempting to prevent T_{ave} from lowering below the no-load value, shut off one or more trains of the system. In three events, the impact at a segment level was treated as an ordinary failure to start or failure to operate. However, in one event, the entire system (three trains) was disabled after running for a period of time. This failure to run was treated as a special case of failure of the entire system. For the operational model, the failure was recovered; this also was quantified. However, this event was omitted from the fault tree calculations for comparison with other AFW risk studies since it was an extreme case not ordinarily modeled in risk assessments.

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 independent and total failure probabilities, the unplanned demands were counted by failure mode as follows. One demand for the suction function of the system was assessed for each event. 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 feed control segments, steam generator feed segments, and turbine steam feed 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 D_{full} 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 exception was the error of commission that was treated separately in the study, and was not counted as successful running of the turbine and motor pump trains.

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.

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.

The CCF probabilities were estimated by counting events rather than individual segment demands and failures. Different types of CCF demands were counted based on the number of segments associated with each AFW design class. For example, CCF failures to start among turbine pump trains were assessed using data just from those plants having more than one AFW turbine pump train. To assess CCF probabilities across pump train types, only those events with demands for more than one type of train were considered.

A-3.1.2 Data-Based Choice of Data Sets

The data were reviewed to see if pump train events could be combined across pump driver type, and if the various feed control segments could be combined. 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 three train types is the same was tested, as was the probability for failure to operate within four types of feed control segments (common feed segments and segments feeding from the three types of pump trains). 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 FTR 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-3.1.4 Additional Assessments of Data Groupings

To further characterize individual probability or rate estimates and their uncertainties, probabilities and confidence bounds were computed in each applicable data set and in the selected pooled data sets for each year, for each AFW design class, and for each plant unit. The hypothesis of no differences across each of these groupings was tested in each data set, using the Pearson chi-square test. Often, the expected cell counts were small enough that the asymptotic chi-square distribution was not a good approximation for the distribution of the test statistic; therefore, the computed P-values were only rough approximations. They are adequate for screening, however.

A premise for these tests is that variation within subgroups in the data be less than the sampling variation, so that the data can be treated as having constant probabilities of failure or failure rates within each subgroup while testing for differences between groups. When statistical evidence of differences within a grouping is identified, this hypothesis is not satisfied. For such data sets, confidence intervals based on overall pooled data are too short, not reflecting all the variability in the data. However, the additional within-subgroup variation is likely to inflate the likelihood of rejecting the hypothesis of no significant systematic variation between years, plant units, or data sources, rather than to mask existing differences in these attributes.

A-3.1.5 Estimation of Failure Probability Distributions using Demands

Three methods of modeling the failure/demand data for the unreliability calculations were employed. They all use 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.

In all three methods, 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 output 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 three methods differ primarily in the selection of a prior distribution, as described below. After describing the basic methods, a summary section describes additional refinements that are applied in conjunction with these methods.

Simple Bayes Method. Where no significant differences were found between groups (such as plants), 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 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.

In the simple Bayes method, 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. In the absence of fitted empirical Bayes distributions described in the next paragraph, it was used both for any single group and as a generic distribution for industry results.

Empirical Bayes Method. When between-group variability could be estimated, the empirical Bayes method was employed.[A-5] Here, the prior beta(a, b) distribution is estimated directly from the data for a failure mode, and it models between-group variation. The model assumes that each group has its own probability of failure, p, drawn from this distribution, and that the number of failures from that group has a binomial distribution governed by the group's p. The likelihood function for the data is based on the observed number of failures and successes in each group and the assumed beta-binomial model. This function of a and b was maximized through an iterative search of the parameter space, using a SAS routine.[A-4] In order to avoid fitting a degenerate, spike-like distribution whose variance is less than the variance of the observed failure counts, the parameter space in this search was restricted to cases in which the sum, a plus b, was less than the total number of observed demands. The a and b corresponding to the maximum likelihood were taken as estimates of the generic beta distribution parameters representing the observed industry data for the failure mode.

The empirical Bayes method uses the empirically estimated distribution for generic results, but it also can yield group-specific results. For this, the generic empirical distribution is used as a prior, which is updated by group-specific data to produce a group-specific posterior distribution. In this process, the generic distribution itself applies for modes and groups, if any, for which no demands occurred (such as plants with no unplanned demands).

The empirical Bayes method was always used in preference to the simple Bayes method when a chi-square test found a statistically significant difference between groups. Because of concerns about the power of the chi-square test, discomfort at drawing a fixed line between significant and nonsignificant, and an engineering belief that there were real differences between the groups, an attempt was made for each failure mode to estimate an empirical Bayes prior distribution over years and over plants. The fitting of a nondegenerate empirical Bayes distribution was used as the index of whether between-group variability could be estimated. The simple Bayes method was used only if no empirical Bayes distribution could be fitted, or if the empirical Bayes distribution was nearly degenerate, with smaller dispersion than the simple Bayes posterior distribution. Sometimes, an empirical Bayes distribution could be fitted even though the chi-square test did not find a between-group variation that was even close to statistically significant. In such a case, the empirical Bayes method was used, but the numerical results were almost the same as from the simple Bayes method.

When more than one empirical Bayes prior distribution was fitted for a failure mode, such as a distribution describing variation across plants and one describing variation across years, the general principle was to select the distribution with the largest variability.

Alternate Method for Some Group-Specific Investigations. Occasionally, the unreliability was modeled by group (such as by plant, by year or by design class) to see if trends existed, such as trends due to time or age. The above methods tend to mask any such trend. The simple Bayes method pools all the data, and thus yields a single generic posterior distribution. The empirical Bayes method typically does not apply to all of the failure modes, and so masks part of the variation. Even when no differences can be seen between groups for any one failure mode, so that the above methods would pool the data for each failure mode, the failures of various modes could all be occurring in a few years or at a few plants. They could thus have a cumulative effect and show a clearly larger unreliability for those few years or plants. Therefore, it is useful to calculate the unreliability for each group (each year or plant) in a way that is very sensitive to the data from that one group.

It is natural, therefore, to update a prior distribution using only the data from the one group. The Jeffreys noninformative prior is suitably diffuse to allow the data to drive the posterior distribution toward any probability range between 0 and 1, if sufficient data exist. However, when the full data set is split into many groups, the groups often have sparse data and few demands. Any Bayesian update method pulls the posterior distribution toward the mean of the prior distribution. More specifically, with beta distributions and binomial data, the estimated posterior mean is $(a+f)/(a+b+d)$. The Jeffreys prior, with $a = b = 0.5$, thus pulls every failure probability toward 0.5. When the data are sparse, the pull toward 0.5 can be quite strong, and can result in every group having a larger estimated unreliability than the population as a whole. In the worst case of a group and failure mode having no demands, the posterior distribution mean is the same as that of the prior, 0.5, even though the overall industry experience may show that the probability for the particular failure mode is, for example, less than 0.1. Because industry experience is relevant for the performance of a particular group, a more practical prior distribution choice is a diffuse prior whose mean equals the estimated industry mean. Keeping the prior diffuse, and therefore somewhat noninformative, allows the data to strongly affect the posterior distribution; and using the industry mean avoids the bias introduced by the Jeffreys prior distribution when the data are sparse.

To do this, the "constrained noninformative prior" was used, a generalization of the Jeffreys prior defined in Reference A-6 and summarized here. The Jeffreys prior is defined by transforming the binomial data model so that the parameter p is transformed, approximately, to a location parameter ϕ. The uniform distribution for ϕ is noninformative. The corresponding distribution for p is the Jeffreys noninformative prior. The generalization replaces the uniform distribution for ϕ with the constrained maximum entropy distribution[A-7] for which the corresponding mean of p is the industry mean from the pooled data, $(f+0.5)/(d+1)$. The maximum entropy distribution for ϕ is, in a precise sense, as flat as possible subject to the constraint. Therefore, it is quite diffuse. The corresponding distribution for p is found. It does not have a convenient form, so the beta distribution for p having the same mean and variance is found. This beta distribution is referred to here as the constrained noninformative prior. It corresponds to an assumed mean for p but to no other prior information. For various assumed means of p, the noninformative prior beta distribution parameters are tabulated in Reference A-6.

For each failure mode of interest, every group-specific failure probability was found by a Bayesian update of the constrained noninformative prior with the group-specific data. The resulting posterior distributions were pulled toward the industry means instead of toward 0.5, but they were sensitive to the group-specific data because the prior distributions for each failure mode were so diffuse.

Additional Refinements in the Application of Group-Specific Bayesian Methods. For both the empirical Bayes distribution and the constrained noninformative prior distribution, beta distribution parameters are estimated from the data. A minor adjustment[A-8] was made in the posterior beta distribution parameters for particular plants, years, and classes to account for the fact that the prior parameters a and b are only estimated, not known. This adjustment increases the group-specific posterior variances somewhat.

Both group-specific failure probability distribution methods use a model, namely, that the failure probability *p* varies between groups according to a beta distribution. In a second refinement, lack of fit to this model was investigated. Data from the most extreme groups (plants or years) were examined to see if the observed failure counts were consistent with the assumed model, or if they were so far in the tail of the beta-binomial distribution that the assumed model was hard to believe. Two probabilities were computed, the probability that, given the resulting beta posterior distribution and binomial sampling, as many or more than the observed number of failures for the group would be observed, and the probability that as many or fewer failures would be observed. If either of these probabilities was low, the results were flagged for further evaluation of whether the model adequately fitted the data. This test was most important with the empirical Bayes method, since the empirical Bayes prior distribution might not be diffuse. No strong evidence against the model was seen in this study. See Atwood[A-4] for more details about this test.

Group-specific updates were not used with the simple Bayes approach because this method is based on the hypothesis that significant differences in the groups do not exist.

A-3.1.6 Assessments and Estimation of Failure Probability Distributions Using Rates

As stated above, the FTR probabilities for each train type were derived from rates of occurrence rather than from failures and demands for the risk-based model. Chi-square test statistics were computed to identify significant differences, if any, among plant AFW design classes, among plant units, and among calendar years for the failure occurrence rates. Bayesian methods similar to those described above were also used. The analyses for rates are based on event counts from Poisson distributions, with gamma distributions that reflect the variation in the occurrence rate across subgroups of interest or across the industry. 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. An *empirical Bayes* method also exists. Here, gamma distribution shape and scale parameters are estimated by identifying the values that maximize the likelihood of the observed data. Finally, the *constrained noninformative prior* method was applied in a manner similar to the other failure modes but again resulting in a gamma distribution for rates. These methods are described further in References A-9 and A-6.

A-3.2 The Combination of Failure Modes

The failure mode probabilities are combined to obtain the unreliability. Two steps were used to obtain the reliability for the AFW 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-10] 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

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

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-11] 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 computed using a similar process. When events occur according to a Poisson process with a fixed occurrence rate, and, for each event, recovery either occurs or fails with a fixed probability, then the resulting nonrecovered occurrences form a Poisson process with an occurrence rate equal to the product of the original occurrence rate and the nonrecovery probability. Therefore, a gamma distribution describing the initial occurrence rate for a failure mode is combined with a beta distribution on the nonrecovery probability using simple multiplication, as above. The process requires selecting gamma and beta distributions for the failure rate and nonrecovery probability, respectively; computing the means and variances of these distributions; computing from these the mean and variance of the product; and identifying the gamma distribution whose mean and variance match the mean and variance of the product.

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 nonrecovery probability 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 AFW system unreliability quantification.

The distribution selection step requires further discussion. Three possibilities exist for the quantification used to describe the risk-based model and to describe the operational model. An updated empirical Bayes distribution may exist for each level within a grouping, such as for each plant. However, when no such empirical Bayes distribution is fit, the data show no strong evidence for variation between plants and a single generic distribution describing industry performance for that failure mode is used for all the plants. In the second possibility, the Jeffreys noninformative prior is the single possibility identified for this distribution. In the third possibility, other generic industry distributions may exist that reflect variation in some other variable, such as year. The distribution showing year-to-year variation is a more accurate model of the industry data for the failure mode than the noninformative distribution that reflects just sampling variation. The Jeffreys noninformative prior updated with industry data is selected only when no other empirical Bayes distributions were found for the data being analyzed.

In the approach to the unreliability modeling used for the trending studies, plant or year-specific beta distributions derived from updating the constrained noninformative prior are used for each failure mode. This approach is used for the group-specific investigations for which a minimal amount of data filtering occurs.

A-3.2.2 AFW System Unreliability

Four series of AFW system unreliability calculations were performed. Because of the complexity of the AFW 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 diesel maintenance and diesel failure to run were not considered since no failures occurred for these modes. The models also included unrecovered suction source path failure probabilities. For each plant, as applicable depending on plant configurations, the fault models included contributions from unrecovered independent failures in feed control segments and the turbine steam supplies. Independent failures of steam generator feed 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 motor-driven pumps, pump-related failures to run of all train types, failures of feed control segments, and failures of the turbine steam supplies. Recovery was also considered for the first three of these four CCF contributors, since CCF events for these occurred during the unplanned demands.

  Alpha factors were used with either the recovered or the total failure probability estimates, as applicable, for the CCF contributors. The total failure probability estimates used either directly or in the recovery probability calculations were based on independent failures plus failures that occurred in common-cause events.

  For the operational models, the failure modes were characterized with beta distributions (updated empirical Bayes distributions reflecting plant variability if possible) 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 except for two issues. First, longer mission times were assumed for the risk-based model. Second, gamma distribution rate parameters and plant-specific mission times were input to the IRRAS system for failures to run.

- Plant-specific models for trend analysis of the operational model with respect to the low-power license date. For these 72 IRRAS runs, beta distribution data similar to the data for the basic operational model were input. However, the distributions were derived from the constrained noninformative prior, and all the distributions were plant-specific Bayesian updates.

- Finally, year-specific models were evaluated for each of the 11 plant design classes. The data (pooled across plants and thus across plant design classes) for each failure mode for each year were used to update the constrained noninformative priors for each failure mode. This process resulted in a block of data covering all the operational model failure modes, for each of the 9 years in the study period. Each year's data set was input into 11 IRRAS models, one for each plant design class.

In the AFW system unreliability calculations, 3,000 simulations were evaluated in most IRRAS runs. For the analysis of unreliability trends with respect to low power-license date, each plant-specific run had 2,000 simulations. The simulation outputs provided estimates of the mean value of the unreliability, together with uncertainty bounds and a standard deviation.

For the year-specific models, one further calculation led to the overall year-by-year AFW unreliability estimates. For each of the 9 years, two weighted averages were computed. The first was a weighted average of the mean unreliability estimates across the plant design classes. The second was a weighted average of the mean of the unreliability squared. In a process like that described in Section A-3.2.1, this mean (of the square of the unreliability) is computed from the estimated mean and variance for the plant design class and year. For both of the weighted averages, the weights were proportional to the number of plants in the associated design class. From the two resulting weighted averages, the mean and variance of a mixture distribution reflecting all the design classes during a given year is computed. A log normal distribution with this mean and variance was selected to describe the AFW operational model industry performance for the given year during the study period, rather than a beta distribution, because the resulting distribution was less skewed and had reasonable lower bounds. The resulting distributions were studied across years to evaluate AFW operational model unreliability trends.

A-4. ESTIMATION OF ADDITIONAL DISTRIBUTIONS FOR TREND ANALYSIS

In addition to the analyses used to estimate system unreliability, the overall frequencies of inoperabilities, failures, and unplanned demands have been analyzed by plant and by year in this series of NRC operational data system studies to identify possible trends and patterns for engineering analysis. For AFW, however, three changes were made. First, because single failures are not required to be reported when redundant trains are available to feed the steam generators, reporting of observed failures and failures in testing is not consistent enough to merit study. Thus, as with the unreliability analysis, only failures observed during unplanned demands on the AFW system were studied. All such failures are expected to be reported since an LER is required for each unplanned demand.

The second change results from the first: the only frequency reasonable to study in time is the frequency of unplanned demands. Since the failure data set is restricted to these events, studying probabilities of failure on demand is appropriate for the failures themselves.

The third change relates to the diverse trains present in the AFW system. For the trend analyses, motor- and turbine-driven trains are studied separately. Diesel train data were not trended since there were only two failures. Feed control segments represent another area of the system with enough failures to consider trends. Thus, the more specific train-level performance is studied rather than AFW failures in general.

Trends and patterns in events that were not classified as failures during unplanned demands were not studied.

The number of demands on a train or feed control segment for a given plant and year is the sum of the demands on that train or segment across the set of AFW system unplanned demands that occurred at the plant during the year. The demands thus are the total number of like trains or segments that were actuated during the unplanned demand events.

Trending the number of failures per demand for the motor and turbine trains and feed control segments differs from the analysis used for the unreliability. Total failures were used, including failures that occurred in CCF events and longer-term failures that were omitted from the operational mission model. The error of commission event that was treated separately for the unreliability analysis was included, bringing in three train-level failures to run. For the pump trains, the analysis does not distinguish between failure modes (e.g., failure to start and failure to run). As in previous failure trending studies, maintenance events were excluded since they are within the designed operation of the AFW system.

Two specific analyses were performed for the unplanned demand frequency and the motor, turbine, and feed control segment probabilities. First, each probability or frequency was compared to determine whether significant differences exist among the plants or among the calendar years. Frequencies and confidence bounds were computed for each rate or probability for each year and plant unit. The hypotheses of simple Poisson or binomial distributions for the occurrences and failures with no differences across the year and plant groupings were 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.

Regardless of whether particular years or plants were identified as having different occurrence frequencies or probabilities, the frequencies and probabilities were also modeled by plant and by year to see if trends exists. For plants, trends with regard to plant age are assessed, as measured from the plant low-power license date. For years, calendar trends are assessed. Least-squares regression analyses are used to assess the trends. The paragraphs below describe certain analysis details associated with these analyses.

With sparse data, estimated event probabilities (event counts divided by demands) are often zero, and regression trend lines through such data often produce negative rate estimates for certain groups (years or ages). Since occurrence frequencies and probabilities cannot be negative, log models are considered. Thus, the analysis determines whether log(frequency) or log(probability) is linear with regard to calendar time or age. An adjustment is needed in order to include frequencies or probabilities that are zero in this model.

Using $0.5/t$ as a frequency estimate or $0.5/d$ as a probability estimate in such cases is not ideal. Such a method penalizes groups that have no failures, increasing only their estimate. Furthermore, industry performance may show that certain events are very rare, so that $0.5/t$ or $0.5/d$ is an unrealistically high estimate. A method that adjusts the estimates uniformly for all the grouping levels (plants or years) and that uses the overall information contained in the industry mean is needed for sparse data and rare events.

As stated in Sections A-3.1.5 and A-3.1.6, constrained noninformative priors can be formed for probabilities and frequencies. This method meets the requirements identified above. Because it also produces estimates for each group (each year or plant) in a way that is very sensitive to the data from that one group, it preserves trends that are present in the unadjusted data. The method, described in Reference A-5, involves updating a prior distribution using only the data from a single group. For frequencies, such distributions are gamma distributions; they are beta distributions for probabilities. Since industry experience is relevant for the performance of a particular group, a practical prior distribution choice is a diffuse prior whose mean equals the estimated industry mean. For frequencies, the mean is constrained to equal (0.5+N)/*T*, where *N* is the total number of events across the industry and *T* is the total exposure time. For probabilities, as stated in Section A-3.1.5, the constrained mean is (0.5+N)/*d*. The specification for the prior distribution mean is the constraint. Keeping the prior diffuse, and therefore somewhat noninformative, allows the data to strongly affect the posterior distribution. This goal is achieved by basing the modeling on a maximum entropy distribution. The details are explained in Reference A-5; the resulting prior distribution for frequencies is a gamma distribution with shape parameter 0.5 and scale parameter *T/(2N+1)*. This process thus adds 0.5 uniformly to each frequency event count and *T/(2N+1)* to each group exposure time. For probabilities, the effect is similar. For both frequencies and probabilities, the mean of the updated posterior distribution is used in the regression trending.

In practice, an additional refinement in the application of the constrained noninformative prior method adjusts the posterior distribution parameters for particular plants and years to account for the fact that one prior distribution scale parameter is only estimated, not known. This adjustment[A-8] increases the group-specific posterior variances somewhat.

For calculating a trend involving one explanatory variable, such as calendar year or low-power license date, standard techniques were used. The logarithms of the calculated rates were fitted to a straight line by weighted least squares. Because the optimal weights depend on the variances of the data, and the estimated variances depend on the fitted means, the values were iteratively reweighted until the estimate stabilized. A confidence band for the fitted line was then found, a band that covers the entire true line with 90% confidence, as discussed in References A-12 and A-13.

For modeling a rate as a function of two explanatory variables, such as calendar year and age, while also allowing for the presence of between-plant differences, a SAS macro GLIMMIX[A-14] was used, documented to some extent in Reference A-15. To do this, the data were prepared as follows.

Consider the rate of unplanned demands, and suppose, for explanatory purposes, that a plant had its low-power license date on April 1, 1980, so that approximately one fourth of the year had elapsed before the low-power license date. Now consider the data for that plant in 1988, say. The unplanned demands occurring in April through December of 1988 occurred when the plant was considered 8 years old. The demands occurring in January through March of 1987 occurred when the plant was considered 7 years old. The critical hours for 1988 were apportioned to the two time periods, 1/4 of them in the first time period and 3/4 in the second time period. Thus, in 1987 through 1995, the plant experienced 18 time periods. The unplanned demands and the critical hours were counted for each time period. The count within each time period was assumed to be Poisson distributed.

The data file therefore contained five fields: the plant identifier, the calendar year, the plant age, the corresponding count of unplanned demands, and the approximate number of critical hours. GLIMMIX was invoked with this data file. It fitted the model

$$\log \lambda_{ijk} = \beta_0 + \beta_1 \times i + \beta_2 \times j + \upsilon_k$$

for year *i*, age *j*, and plant *k*. The year and age are integers, and υ_k is a random variable, assumed normally distributed.

For a plant with a given low-power license date, a 90% prediction band was found, essentially using the methods described in Reference A-12. It has the interpretation

Pr(a random data set generates a band that contains log λ for all years and a random plant) ≥ 0.90.

The calculation was based on the approximate normal distribution for $\log \hat{\lambda}$ and the assumed normal distribution of υ. The width of the band reflected both the uncertainty in the estimates of the βs and on the variance of υ, although the second term dominated in the case considered.

Finally, this prediction band was given a Bayesian interpretation, corresponding to a lognormal uncertainty distribution for λ. The 5th and 95th percentiles of λ were set to the prediction limits, and the mean of λ was calculated. The mean and percentiles are plotted in the body of the report.

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Appendix B

AFW Operational Data, 1987–1995

Appendix B
AFW Operational Data, 1987–1995

In subsections below, listings of the data used for the auxiliary feedwater (AFW) system reliability study are provided. First, the results of the data classification for inoperabilities are listed, then the results of the classification of the unplanned demands.

The AFW 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 AFW system for the years 1987 through 1995. To ensure as complete a data set as possible, the SCSS database was also searched for all safety injection actuations and critical reactor trips for plants that have an AFW system. These records would provide an additional source of AFW actuations because (1) the AFW system is typically demanded as a result of safety injection demand and (2) AFW may be required to start following a reactor trip as a result of either steam generator level shrink, or feedwater problems experienced as part of the trip.

Differences may exist among plants interpreting what is an AFW ESF actuation or failure and hence what is reportable. 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 AFW 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.* (AFW ESF actuations were found and reported as ESF actuations for all plants in the study.) AFW 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 a more complete description of the event, which is needed to determine successful operation or failure of AFW.

B-1. AFW INOPERABILITIES

The information encoded in the SCSS database, and included in this study, encompasses both actual and potential AFW failures during all plant operating conditions and testing. In this report, the term *inoperability* is used to describe any AFW component malfunction either actual or potential, except an ESF actuation, in which an LER was submitted in accordance with the requirements identified in 10 CRF 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. The term *fault* is used in this study to refer to the remaining subset of inoperabilities that were not classified as failures. Specifically for an event to be classified as a fault, when considering all the data provided in the full text of the LER, the segment would have functioned successfully for a risk-based mission. The subset of inoperabilities classified as faults were primarily potential failures. 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 inoperability events that were classified for inclusion in the study. The events that were classified as failures include the applicable failure mode. For the unreliability estimation process, only the failures that occurred during an unplanned demand were used to estimate unreliability. A listing and description of the events used in the unreliability analysis are provided in Appendix C.

B-2. AFW UNPLANNED DEMANDS

To estimate reliability, information on the frequency and nature of AFW 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 either actual low steam generator water level conditions, safety injection demands, or losses of normal feedwater (main feedwater pump trips or low main feedwater header pressure). Other plant conditions may have also resulted in an unplanned demand of AFW based on the plant-specific design of the AFW initiation circuit. These initiations of AFW 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 not classified as unplanned demands. For example, the shorting of test leads or blown fuses that resulted in a demand signal were not counted as a valid demand.

The LERs identified from the SCSS database search were reviewed to determine the nature and frequency of AFW 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 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 AFW 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 initiation setpoints, operating characteristics, and schematic for the system was necessary to capture the unplanned demand frequency 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 AFW based on the information provided in the IPE or FSAR. For example, the plant would state in the LER that a double-low water level condition existed in two steam generators during the event. Based on the information provided in the FSAR for the particular plant, the condition would result in the automatic start of both electric-motor-driven pumps and the turbine-driven pump. However, no explicit identification of the AFW pump start was found in the LER. Therefore, based on the narrative of each LER and plant-specific knowledge concerning AFW initiation and operation, it was possible to determine a relatively accurate number of AFW 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 AFW demands, the reader/analyst should not compare the results used in this study to a simple SCSS database search for an AFW 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 AFW inoperabilities, provides the results of the search and categorization of AFW 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: SGFDSGMT, steam generator feed segment; TDP, turbine-driven pump; INSTRMNT, instrumentation and control; MFDSGMT, motor-driven pump feed segment; TDPSTM, turbine-driven pump steam supply; DDP, diesel-driven pump; COMFDSMT, common feed control segment; MDP, motor-driven pump; CSTSUCTN, pump 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; Water accum, water accumulation in the steam supply lines to the turbine-driven pump or in the turbine casing; Support sys., the malfunction associate with a support system that ultimately prevented operation of a segment of AFW (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 steam generator level); Environment, the malfunction was the result of an environmental problem (an example would be an Asiatic clam infestation).
Method of discovery	The method of discovery identifies how the inoperability was found. Demand, unplanned demand; Other, discovered through the normal course of routine plant operations (this category includes operator walkdowns, control room annunicators or alarms, etc.); 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 (the designator FTRP is used to identify failures associated to the pump that are independent of the driver, e.g., impeller failure); 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. Auxiliary feedwater inoperability 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 Unit 1	31387001	01/01/87	SGFDSGMT	1	Design	Review	N/A	False	False	False
Arkansas Unit 1	31388009	09/22/88	SGFDSGMT	1	Design	Review	N/A	False	False	False
Arkansas Unit 1	31388021	11/26/88	TDP	1	Maintenance	Other	FTS	False	False	False
Arkansas Unit 1	31389022	03/10/89	SGFDSGMT	1	Design	Review	N/A	False	False	False
Arkansas Unit 1	31392005	05/19/92	TDP	1	Maintenance	Test	FTR	False	False	False
Arkansas Unit 1	31394001	01/31/94	INSTRMNT	1	Hardware	Test	FTS	False	False	False
Arkansas Unit 1	31395005	04/20/95	MFDSGMT	2	Hardware	Other	FTO	True	True	False
Arkansas Unit 2	36888023	02/19/88	TDPSTM	1	Hardware	Test	N/A	False	False	False
Arkansas Unit 2	36889006	04/18/89	TDP	1	Hardware	Demand	FTS	True	False	False
Arkansas Unit 2	36890024	12/05/90	TDP	1	Water accum.	Test	FTS	False	False	False
Arkansas Unit 2	36894002	04/22/94	TDP	1	Hardware	Other	FTS	False	False	False
Beaver Valley Unit 1	33491012	04/15/91	SGFDSGMT	3	Design	Review	N/A	False	False	False
Beaver Valley Unit 1	33491018	06/06/91	SGFDSGMT	3	Design	Review	N/A	False	False	False
Beaver Valley Unit 1	33491022	07/20/91	MDP	1	Hardware	Demand	N/A	False	False	False
Beaver Valley Unit 2	41287035	11/10/87	COMFDSMT	1	Hardware	Demand	FTO	False	False	False
Beaver Valley Unit 2	41289015	05/14/89	TDP	1	Hardware	Test	FTR	False	False	False
Beaver Valley Unit 2	41289025	09/10/89	COMFDSMT	2	Hardware	Other	N/A	False	False	False
Beaver Valley Unit 2	41290008	07/02/90	TDP	1	Hardware	Demand	FTS	False	False	False
Beaver Valley Unit 2	41291004	10/18/91	TDP	1	Design	Review	N/A	False	False	False
Beaver Valley Unit 2	41292004	03/30/92	MDP	1	Support sys.	Review	N/A	False	False	False
Beaver Valley Unit 2	41293001	01/26/93	COMFDSMT	1	Design	Review	N/A	False	False	False
Beaver Valley Unit 2	41293014	11/29/93	TDP	1	Hardware	Test	FTR	False	False	False
Braidwood Unit 1	45687060	12/06/87	MDP	1	Support sys.	Demand	FTS	True	False	False
Braidwood Unit 1	45693006	12/09/93	CSTSUCTN	1	Hardware	Review	N/A	False	False	False
Braidwood Unit 2	45693006	12/09/93	CSTSUCTN	1	Hardware	Review	N/A	False	False	False
Braidwood Unit 2	45789002	05/11/89	MFDSGMT	1	Hardware	Demand	FTO	True	False	False
Braidwood Unit 2	45789007	11/01/89	MDP	2	Personnel	Test	FTS	False	False	False
Bryon Unit 1	45493004	12/08/93	CSTSUCTN	1	Hardware	Review	N/A	False	False	False
Byron Unit 2	45493004	12/08/93	CSTSUCTN	1	Hardware	Review	N/A	False	False	False
Byron Unit 2	45587007	05/04/87	MDP	1	Support sys.	Demand	FTS	True	False	False
Byron Unit 2	45588005	05/06/88	DDP	1	Hardware	Demand	FTR	False	False	False
Byron Unit 2	45588008	07/14/88	DDP	1	Hardware	Demand	FTS	True	False	False

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
Callaway	48387003	04/02/87	MFDSGMT	1	Hardware	Other	FTO	False	False	False
Callaway	48387022	08/28/87	CSTSUCTN	1	Personnel	Test	N/A	False	False	False
Callaway	48392005	04/10/92	TDPSTM	1	Hardware	Other	FTO	False	False	False
Calvert Cliffs Unit 1	31787012	07/23/87	TDP	1	Hardware	Demand	FTS	True	False	False
Calvert Cliffs Unit 1	31788014	10/29/88	TDPSTM	1	Hardware	Other	N/A	False	False	False
Calvert Cliffs Unit 1	31789010	06/14/89	SGFDSGMT	1	Design	Review	N/A	False	False	False
Calvert Cliffs Unit 1	31792008	11/24/92	TDP	1	Hardware	Demand	FTR	False	False	False
Calvert Cliffs Unit 2	31889004	03/01/89	TDP	1	Maintenance	Other	FTS	False	False	False
Calvert Cliffs Unit 2	31895002	01/13/95	TDPSTM	1	Hardware	Demand	FTO	False	False	False
Catawba Unit 1	41387026	07/06/87	MFDSGMT	1	Hardware	Demand	FTO	True	False	False
Catawba Unit 1	41388015	03/09/88	MFDSGMT	2	Environment	Other	FTO	False	False	True
Catawba Unit 1	41389007	01/27/89	TDP	1	Hardware	Test	FTS	False	False	False
Catawba Unit 1	41389007	01/27/89	TDP	1	Hardware	Test	FTR	False	False	False
Catawba Unit 1	41391015	07/10/91	MFDSGMT	1	Hardware	Demand	FTO	True	False	False
Catawba Unit 1	41392004	03/14/92	MFDSGMT	1	Maintenance	Test	N/A	True	False	False
Catawba Unit 1	41392008	07/12/92	MFDSGMT	1	Design	Demand	FTO	False	False	False
Catawba Unit 1	41393012	12/25/93	TDPSTM	2	Personnel	Other	FTO	False	True	False
Catawba Unit 2	41487002	01/28/87	MFDSGMT	4	Hardware	Demand	N/A	False	False	False
Catawba Unit 2	41487024	08/07/87	TFDSGMT	1	Hardware	Test	FTO	False	False	False
Catawba Unit 2	41487026	09/12/87	TDP	1	Hardware	Test	FTR	False	False	False
Catawba Unit 2	41487029	11/03/87	TDP	1	Maintenance	Demand	FTS	False	False	False
Catawba Unit 2	41488012	03/09/88	MFDSGMT	2	Environment	Demand	FTO	False	False	True
Catawba Unit 2	41488012	03/09/88	CSTSUCTN	1	Hardware	Demand	FTO	True	False	False
Catawba Unit 2	41489010	03/14/89	MFDSGMT	1	Hardware	Other	FTO	False	False	False
Catawba Unit 2	41489017	07/31/89	TDP	1	Hardware	Test	FTS	False	False	False
Catawba Unit 2	41489019	09/12/89	CSTSUCTN	1	Personnel	Other	FTO	False	False	True
Catawba Unit 2	41492003	03/02/92	MFDSGMT	4	Design	Review	N/A	False	False	False
Catawba Unit 2	41492003	03/02/92	TFDSGMT	4	Design	Review	N/A	False	False	False
Catawba Unit 2	41494007	10/18/94	MFDSGMT	4	Personnel	Other	FTO	False	False	True
Catawba Unit 2	41494007	10/18/94	TFDSGMT	2	Personnel	Other	FTO	False	False	True
Comanche Peak Unit 1	44590004	03/12/90	MFDSGMT	2	Maintenance	Demand	N/A	False	False	False
Comanche Peak Unit 1	44590042	11/20/92	INSTRMNT	2	Personnel	Other	FTS	False	False	True
Comanche Peak Unit 1	44591010	03/22/91	MFDSGMT	1	Personnel	Other	FTO	False	False	False
Comanche Peak Unit 1	44591016	04/18/91	MFDSGMT	1	Hardware	Test	FTO	False	False	False

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
Comanche Peak Unit 1	44591029	12/04/91	TDPSTM	2	Personnel	Other	FTO	False	True	False
Comanche Peak Unit 1	44595003	06/11/95	TDP	1	Hardware	Demand	FTS	False	False	False
Comanche Peak Unit 2	44595004	06/21/95	TDP	1	Water accum	Test	FTS	False	False	False
Cook Unit 1	31589001	01/16/89	TFDSGMT	1	Maintenance	Demand	FTO	False	False	False
Cook Unit 1	31589013	09/06/89	MDP	1	Design	Other	N/A	False	False	False
Cook Unit 1	31593002	06/09/93	TDP	2	Design	Other	N/A	False	False	False
Cook Unit 2	31689017	10/19/89	TDP	1	Hardware	Test	FTR	False	False	False
Cook Unit 2	31691004	03/13/91	TDP	1	Hardware	Demand	FTS	True	False	False
Cook Unit 2	31691006	08/01/91	TDP	1	Hardware	Demand	FTR	False	False	False
Cook Unit 2	31693007	08/02/93	MFDSGMT	2	Hardware	Demand	FTO	True	False	True
Cook Unit 2	31695005	08/29/95	MFDSGMT	2	Maintenance	Demand	FTO	False	False	True
Crystal River 3	30287002	02/21/87	MDP	1	Procedure	Test	FTS	False	False	True
Crystal River 3	30287002	02/21/87	TDP	1	Procedure	Test	FTS	False	False	True
Crystal River 3	30287013	07/12/87	TDP	1	Procedure	Test	FTS	False	False	True
Crystal River 3	30287013	07/12/87	MDP	1	Procedure	Test	FTS	False	False	True
Crystal River 3	30287017	08/08/87	TDPSTM	1	Procedure	Other	N/A	False	False	False
Crystal River 3	30288002	01/07/88	TDP	1	Water accum	Demand	FTS	True	False	False
Crystal River 3	30288014	06/21/88	SGFDSGMT	1	Hardware	Other	N/A	False	False	False
Crystal River 3	30289023	06/16/89	MDP	1	Hardware	Demand	FTS	True	False	False
Crystal River 3	30291013	11/19/91	TDP	1	Personnel	Other	N/A	False	False	False
Crystal River 3	30291013	11/19/91	MDP	1	Hardware	Other	FTS	False	False	False
Crystal River 3	30292004	04/24/92	TFDSGMT	2	Design	Other	N/A	False	False	False
Crystal River 3	30292004	04/24/92	MFDSGMT	1	Design	Review	N/A	False	False	False
Crystal River 3	30292007	05/01/92	TDPSTM	2	Design	Review	N/A	False	False	False
Crystal River 3	30295015	08/30/95	INSTRMNT	2	Procedure	Review	N/A	False	False	False
Crystal River 3	30295016	08/31/95	INSTRMNT	2	Procedure	Review	N/A	False	False	False
Crystal River 3	30295027	12/06/95	TDP	1	Personnel	Other	N/A	False	False	False
Crystal River 3	30295027	12/06/95	MDP	1	Personnel	Other	N/A	False	False	False
Davis-Besse	34687004	01/12/87	TDPSTM	1	Hardware	Test	N/A	False	False	False
Davis-Besse	34692004	04/27/92	TDP	1	Design	Review	N/A	False	False	False
Davis-Besse	34693004	04/28/93	TDPSTM	1	Design	Review	N/A	False	False	False
Davis-Besse	34693007	11/12/93	TDPSTM	1	Maintenance	Test	N/A	False	False	False
Diablo Canyon Unit 2	32388024	12/31/88	TDP	1	Maintenance	Test	FTR	False	False	False
Diablo Canyon Unit 2	32389001	01/17/89	TDPSTM	1	Maintenance	Other	FTO	False	False	False

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 Unit 2	32389001	01/17/89	MFDSGMT	1	Maintenance	Other	FTO	False	False	False
Diablo Canyon Unit 2	32389002	02/12/89	TDP	1	Maintenance	Test	N/A	False	False	False
Farley Unit 1	34889007	11/12/89	MDP	2	Maintenance	Demand	FTS	True	False	True
Farley Unit 1	34891005	05/18/91	TDP	1	Personnel	Other	FTR	False	False	False
Farley Unit 1	34894004	06/02/94	TDPSTM	1	Hardware	Test	N/A	False	False	False
Fort Calhoun	28587022	04/15/87	CSTSUCTN	1	Personnel	Other	N/A	False	False	False
Fort Calhoun	28589016	06/16/89	TDP	1	Design	Review	N/A	False	False	False
Fort Calhoun	28590003	02/16/90	COMFDSMT	2	Design	Review	N/A	False	False	False
Fort Calhoun	28590009	03/16/90	COMFDSMT	2	Design	Review	N/A	False	False	False
Fort Calhoun	28590016	05/11/90	TDP	1	Design	Review	N/A	False	False	False
Fort Calhoun	28593019	12/09/93	MDP	1	Procedure	Test	FTS	False	False	False
Fort Calhoun	28593019	12/09/93	TDPSTM	2	Personnel	Other	FTO	False	True	False
Ginna	24490013	12/11/90	MDP	1	Design	Demand	FTR	False	False	False
Ginna	24492002	02/03/92	TDP	1	Hardware	Demand	N/A	False	False	False
Haddam Neck	21390004	03/16/90	COMFDSMT	4	Hardware	Test	FTO	False	False	True
Haddam Neck	21390016	08/20/90	TDP	2	Design	Review	FTS	False	False	False
Haddam Neck	21391005	03/04/91	COMFDSMT	2	Hardware	Test	FTO	False	False	True
Harris	40087035	06/17/87	TDP	1	Water accum	Demand	FTS	False	False	False
Harris	40089001	01/16/89	TDP	1	Water accum	Demand	FTS	True	False	False
Harris	40089006	03/14/89	TDP	1	Maintenance	Demand	MOOS	False	False	False
Harris	40089017	10/09/89	TDP	1	Hardware	Demand	FTS	True	False	False
Harris	40089020	10/31/89	MFDSGMT	2	Maintenance	Other	N/A	False	False	False
Indian Pt. Unit 2	24787003	02/02/87	MDP	2	Hardware	Test	N/A	False	False	False
Indian Pt. Unit 2	24787006	04/30/87	MDP	2	Support sys.	Review	N/A	False	False	False
Indian Pt. Unit 2	24791001	01/07/91	MDP	1	Maintenance	Demand	FTS	False	False	False
Indian Pt. Unit 2	24792007	04/13/92	MDP	2	Design	Demand	FTS	True	False	True
Indian Pt. Unit 2	24793011	01/30/93	MFDSGMT	1	Maintenance	Test	FTO	False	False	False
Indian Pt. Unit 3	28687001	01/31/87	MDP	1	Maintenance	Demand	FTS	True	False	False
Indian Pt. Unit 3	28687005	04/30/87	MDP	1	Design	Review	FTS	False	True	False
Indian Pt. Unit 3	28688002	03/31/88	MDP	1	Hardware	Demand	FTS	True	False	False
Indian Pt. Unit 3	28693004	01/13/93	TDP	1	Maintenance	Test	FTS	False	False	False
Kewaunee	30588011	08/31/88	TDPSTM	2	Personnel	Other	FTO	False	True	False
Kewaunee	30589012	06/22/89	INSTRMNT	2	Design	Review	N/A	False	False	False
Kewaunee	30590006	04/14/90	TDPSTM	2	Personnel	Other	FTO	False	True	False
Kewaunee	30591001	02/01/91	TDP	1	Design	Review	N/A	False	False	False

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
Kewaunee	30591008	09/10/91	TDP	1	Design	Review	N/A	False	False	False
Kewaunee	30591012	12/04/91	TDP	1	Personnel	Other	N/A	False	False	False
Kewaunee	30592010	04/13/92	TDPSTM	1	Personnel	Other	FTO	False	True	False
Kewaunee	30593001	04/21/93	TFDSGMT	1	Design	Review	N/A	False	False	False
Kewaunee	30593018	10/12/93	TDP	1	Hardware	Other	N/A	False	False	False
Kewaunee	30595007	11/09/95	TDP	1	Maintenance	Test	FTS	False	False	False
Maine Yankee	30990006	09/13/90	COMFDSMT	3	Procedure	Other	N/A	False	False	False
Maine Yankee	30991004	02/02/91	INSTRMNT	2	Design	Review	N/A	False	False	False
Maine Yankee	30992006	04/11/92	MDP	2	Procedure	Test	FTS	False	False	True
Maine Yankee	30993020	10/12/91	MDP	2	Personnel	Other	FTS	False	False	True
McGuire Unit 1	36987009	04/15/87	TDP	1	Maintenance	Demand	MOOS	False	False	False
McGuire Unit 1	36988007	04/16/88	TDPSTM	1	Hardware	Demand	N/A	False	False	False
McGuire Unit 1	36988021	08/17/88	INSTRMNT	1	Hardware	Other	FTS	False	False	False
McGuire Unit 1	36988045	12/10/88	MFDSGMT	1	Maintenance	Other	FTO	False	False	False
McGuire Unit 1	36989010	05/15/89	TDP	4	Design	Review	N/A	False	False	False
McGuire Unit 1	36989010	05/15/89	MDP	4	Design	Review	N/A	False	False	False
McGuire Unit 1	36992006	04/30/92	CSTSUCTN	1	Hardware	Other	FTO	False	True	False
McGuire Unit 1	36992011	12/10/92	MDP	1	Hardware	Other	FTR	False	False	False
McGuire Unit 1	36994008	11/01/94	TFDSGMT	1	Design	Test	N/A	False	False	False
McGuire Unit 1	36994008	11/01/94	MFDSGMT	1	Design	Test	N/A	False	False	False
McGuire Unit 2	36989010	05/15/89	TDP	4	Design	Review	N/A	False	False	False
McGuire Unit 2	36989010	05/15/89	MDP	4	Design	Review	N/A	False	False	False
McGuire Unit 2	36992006	04/30/92	CSTSUCTN	1	Hardware	Other	FTO	False	True	False
McGuire Unit 2	36992011	12/10/92	TDP	1	Hardware	Other	FTR	False	False	False
McGuire Unit 2	37091002	05/15/91	TDP	1	Maintenance	Other	FTR	False	False	False
McGuire Unit 2	37091004	04/22/91	TDP	1	Maintenance	Other	FTR	False	False	False
Millstone Unit 2	33687012	11/16/87	MDP	1	Hardware	Demand	FTS	True	False	False
Millstone Unit 2	33693022	09/03/93	CSTSUCTN	1	Design	Review	N/A	False	False	False
Millstone Unit 2	33694001	01/18/94	COMFDSMT	2	Hardware	Test	FTO	False	False	False
Millstone Unit 2	33694015	05/19/94	INSTRMNT	2	Design	Review	N/A	False	False	False
Millstone Unit 3	42387026	05/14/87	MDP	1	Maintenance	Demand	MOOS	False	False	False
Millstone Unit 3	42388016	04/25/88	MDP	2	Personnel	Other	FTS	False	False	True
Millstone Unit 3	42389009	05/11/89	MFDSGMT	1	Hardware	Demand	FTO	False	False	False
Millstone Unit 3	42389009	05/11/89	TDP	1	Maintenance	Demand	MOOS	False	False	False
Millstone Unit 3	42389026	10/23/89	TDP	1	Maintenance	Test	FTR	False	False	False
Millstone Unit 3	42394006	03/15/94	TDPSTM	1	Design	Review	N/A	False	False	False

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 Unit 3	42394011	09/08/94	TDP	1	Hardware	Test	FTS	False	False	False
Millstone Unit 3	42394014	11/21/94	TDP	1	Water accum	Test	FTS	False	False	False
North Anna Unit 1	33888002	01/08/88	TDP	1	Hardware	Demand	FTR	False	False	False
North Anna Unit 1	33892008	03/19/92	INSTRMNT	2	Procedure	Test	FTS	False	False	True
North Anna Unit 1	33893014	04/11/93	TDP	1	Maintenance	Test	FTS	False	False	False
North Anna Unit 2	33987005	06/01/87	TDP	1	Personnel	Other	FTS	False	False	True
North Anna Unit 2	33987005	06/01/87	MDP	2	Personnel	Other	FTS	False	False	True
North Anna Unit 2	33993002	04/16/93	MDP	2	Personnel	Demand	EOC	True	False	True
North Anna Unit 2	33993002	04/16/93	TDP	1	Personnel	Demand	EOC	True	False	True
North Anna Unit 2	33994001	01/05/94	TDP	1	Personnel	Other	FTS	False	False	False
Oconee Unit 1	26989001	01/02/89	COMFDSMT	1	Hardware	Demand	FTO	True	False	False
Oconee Unit 1	26990009	06/04/90	CSTSUCTN	1	Personnel	Other	N/A	False	False	False
Oconee Unit 1	26991007	07/03/91	INSTRMNT	2	Support sys.	Demand	FTS	True	True	False
Oconee Unit 1	26992004	05/08/92	COMFDSMT	1	Hardware	Demand	FTO	True	False	False
Oconee Unit 2	27092004	10/19/92	TDP	1	Water accum	Demand	N/A	False	False	False
Oconee Unit 2	27094001	02/08/94	MDP	1	Hardware	Other	FTS	False	False	True
Oconee Unit 2	27094002	04/06/94	MDP	1	Hardware	Demand	MOOS	True	False	False
Oconee Unit 3	28791007	07/03/91	COMFDSMT	1	Hardware	Demand	FTO	True	False	False
Oconee Unit 3	28793001	01/26/93	COMFDSMT	1	Personnel	Other	FTO	False	False	True
Palisades	25594020	12/07/94	COMFDSMT	1	Hardware	Test	FTO	False	False	False
Palisades	25595006	06/29/95	MDP	1	Design	Review	FTR	False	False	True
Palisades	25595006	06/29/95	TDP	1	Design	Review	FTR	False	False	True
Palo Verde Unit 1	52887025	11/27/87	TDPSTM	2	Maintenance	Test	FTO	False	False	True
Palo Verde Unit 1	52888013	03/25/88	MDP	1	Hardware	Test	FTR	False	False	True
Palo Verde Unit 1	52888013	03/25/88	TDP	1	Hardware	Test	FTR	False	False	True
Palo Verde Unit 1	52893010	11/05/93	MFDSGMT	2	Design	Review	N/A	False	False	False
Palo Verde Unit 2	52887025	11/27/87	TDPSTM	2	Maintenance	Test	FTO	False	False	True
Palo Verde Unit 2	52888013	03/25/88	TDP	1	Hardware	Test	FTR	False	False	True
Palo Verde Unit 2	52888013	03/25/88	MDP	1	Hardware	Test	FTR	False	False	True
Palo Verde Unit 2	52893010	11/05/93	MFDSGMT	2	Design	Review	N/A	False	False	False

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
Palo Verde Unit 3	52888013	03/25/88	TDP	1	Hardware	Test	FTR	False	False	True
Palo Verde Unit 3	52888013	03/25/88	MDP	1	Hardware	Test	FTR	False	False	True
Palo Verde Unit 3	52893010	11/05/93	MFDSGMT	2	Design	Review	N/A	False	False	False
Prairie Island Unit 1	28287007	05/16/87	TDP	1	Hardware	Test	FTS	False	False	False
Prairie Island Unit 1	28287007	05/16/87	TDP	1	Environment	Other	FTR	False	False	True
Prairie Island Unit 1	28287007	05/16/87	MDP	1	Environment	Test	FTR	False	False	True
Prairie Island Unit 2	30690001	10/09/90	TDP	1	Procedure	Test	FTS	False	False	True
Prairie Island Unit 2	30690001	10/09/90	MDP	1	Procedure	Test	FTS	False	False	True
Robinson 2	26187018	06/15/87	MDP	1	Personnel	Demand	FTS	False	False	False
Robinson 2	26189010	08/16/89	COMSUCTN	1	Design	Review	FTO	False	False	False
St. Lucie Unit 2	38987003	04/09/87	TDP	1	Hardware	Demand	FTS	False	False	False
St. Lucie Unit 2	38989007	09/23/89	MDP	1	Hardware	Demand	FTR	False	False	False
St. Lucie Unit 2	38990001	01/14/90	TDP	1	Hardware	Demand	FTS	True	False	False
Salem Unit 1	27287017	11/13/87	TDPSTM	1	Design	Review	N/A	False	False	False
Salem Unit 1	27289027	06/19/89	MFDSGMT	1	Hardware	Demand	N/A	False	False	False
Salem Unit 1	27289029	10/16/89	MDP	2	Support sys.	Other	FTS	False	True	False
Salem Unit 1	27291002	01/24/91	TDP	1	Hardware	Other	N/A	False	False	False
Salem Unit 1	27291036	12/13/91	SGFDSGMT	4	Design	Review	N/A	False	False	False
Salem Unit 1	27292019	08/05/92	TDP	1	Maintenance	Test	FTS	False	False	False
Salem Unit 1	27295012	12/16/95	TDPSTM	1	Design	Review	N/A	False	False	False
San Onofre Unit 2	36189001	01/12/89	MDP	1	Hardware	Test	FTR	False	False	False
San Onofre Unit 2	36190012	08/26/90	TDP	1	Water accum	Test	FTS	False	False	False
San Onofre Unit 2	36190015	12/04/90	MDP	2	Maintenance	Other	N/A	False	False	False
San Onofre Unit 2	36191014	09/10/91	TDP	1	Water accum	Test	FTS	False	False	False
San Onofre Unit 2	36192007	02/22/92	TDP	1	Water accum	Test	FTS	False	False	False
San Onofre Unit 2	36193006	09/08/93	TDPSTM	1	Design	Review	N/A	False	False	False
San Onofre Unit 3	36290011	07/22/90	TDPSTM	1	Hardware	Other	N/A	False	False	False
San Onofre Unit 3	36295002	08/22/95	COMFDSMT	2	Personnel	Other	N/A	False	False	False
Seabrook	44390015	06/20/90	COMFDSMT	1	Design	Demand	FTO	False	False	False

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
Sequoyah Unit 1	32789005	02/10/89	MFDSGMT	1	Maintenance	Demand	FTO	False	False	False
Sequoyah Unit 1	32790004	02/21/90	TDPSTM	1	Maintenance	Other	N/A	False	False	False
Sequoyah Unit 2	32888012	03/05/88	TFDSGMT	1	Maintenance	Other	FTO	False	False	False
Sequoyah Unit 2	32888023	05/19/88	MDP	1	Maintenance	Demand	MOOS	False	False	False
Sequoyah Unit 2	32888026	06/11/88	MFDSGMT	2	Maintenance	Other	FTO	False	False	True
Sequoyah Unit 2	32888027	06/06/88	TFDSGMT	1	Maintenance	Demand	FTO	False	False	False
Sequoyah Unit 2	32889008	07/10/89	MFDSGMT	2	Hardware	Demand	FTO	True	False	True
South Texas Unit 1	49888032	02/28/88	TDP	1	Hardware	Test	FTR	False	False	True
South Texas Unit 1	49888032	02/28/88	MDP	3	Hardware	Test	FTR	False	False	True
South Texas Unit 1	49890006	07/30/90	MFDSGMT	2	Personnel	Demand	FTO	True	True	False
South Texas Unit 1	49892006	03/18/92	TFDSGMT	1	Personnel	Other	FTO	False	False	True
South Texas Unit 1	49892006	03/18/92	MFDSGMT	3	Personnel	Other	FTO	False	False	True
South Texas Unit 1	49893007	02/04/93	TDP	1	Water accum	Test	FTS	False	False	False
South Texas Unit 2	49989013	04/15/89	TDP	1	Personnel	Demand	FTS	False	False	False
South Texas Unit 2	49993004	02/03/93	TDP	1	Water accum	Test	FTS	False	False	False
Summer	39587015	06/16/87	MDP	1	Maintenance	Demand	MOOS	True	False	False
Summer	39588007	06/01/88	MDP	1	Support sys.	Demand	FTS	True	False	False
Surry Unit 1	28089032	07/27/92	CSTSUCTN	1	Personnel	Other	FTO	False	False	False
Surry Unit 1	28091006	04/19/91	MDP	1	Procedure	Other	FTS	False	False	False
Surry Unit 1	28095001	01/08/95	TDP	1	Hardware	Demand	FTS	False	False	False
Surry Unit 2	28188004	03/27/88	COMFDSMT	2	Hardware	Demand	FTO	False	False	False
Surry Unit 2	28188010	05/16/88	MDP	2	Hardware	Demand	FTR	False	False	True
Surry Unit 2	28188010	05/16/88	TDP	1	Hardware	Other	FTR	False	False	True
Surry Unit 2	28192007	06/15/92	COMFDSMT	1	Personnel	Other	N/A	False	False	False
Turkey Point Unit 3	25087004	01/12/87	SGFDSGMT	1	Hardware	Other	N/A	False	False	False
Turkey Point Unit 3	25087006	01/23/87	SGFDSGMT	1	Hardware	Other	N/A	False	False	False
Turkey Point Unit 4	25187001	01/06/87	TDP	1	Maintenance	Demand	MOOS	False	False	False
Turkey Point Unit 4	25187014	07/11/87	TDPSTM	1	Hardware	Other	N/A	False	False	False
Turkey Point Unit 4	25187015	07/15/87	SGFDSGMT	3	Personnel	Other	N/A	False	False	False
Turkey Point Unit 4	25192007	09/29/92	TDP	1	Hardware	Demand	MOOS	False	False	False

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 Unit 1	42487009	03/20/87	MFDSGMT	2	Hardware	Demand	FTO	False	True	False
Vogtle Unit 1	42487020	04/30/87	MFDSGMT	1	Hardware	Other	FTO	False	False	False
Vogtle Unit 1	42487036	06/15/87	INSTRMNT	2	Maintenance	Other	FTS	False	False	True
Vogtle Unit 1	42487062	10/28/87	TFDSGMT	4	Personnel	Other	FTO	False	False	True
Vogtle Unit 1	42487062	10/28/87	MFDSGMT	4	Personnel	Other	FTO	False	False	True
Vogtle Unit 1	42487066	11/11/87	MDP	1	Support sys.	Demand	MOOS	False	False	False
Vogtle Unit 1	42488008	04/07/88	MFDSGMT	1	Hardware	Demand	FTO	False	False	False
Vogtle Unit 1	42489005	02/10/89	TDP	1	Hardware	Demand	FTS	False	False	False
Vogtle Unit 1	42489008	02/23/89	TDP	1	Design	Review	N/A	False	False	False
Vogtle Unit 1	42492007	09/09/92	TDP	1	Hardware	Test	FTS	False	False	False
Vogtle Unit 2	42589013	03/30/89	TDP	1	Maintenance	Other	N/A	False	False	False
Vogtle Unit 2	42593007	10/19/93	TDP	1	Hardware	Test	FTS	False	False	False
Waterford 3	38287020	07/31/87	TDP	1	Hardware	Demand	FTS	False	False	False
Waterford 3	38288033	12/08/88	COMFDSMT	1	Hardware	Demand	FTO	True	False	False
Wolf Creek	48287037	09/10/87	TDP	1	Personnel	Demand	FTR	True	False	False
Wolf Creek	48287037	09/10/87	MFDSGMT	4	Personnel	Demand	FTO	False	False	True
Wolf Creek	48290018	08/03/90	TDP	1	Maintenance	Other	N/A	False	False	False
Wolf Creek	48290021	10/01/90	TDP	1	Hardware	Other	N/A	False	False	False
Wolf Creek	48293010	05/08/93	MDP	2	Personnel	Other	FTS	False	False	True
Zion Unit 1	29588019	10/25/88	MDP	2	Design	Review	FTS	False	False	True
Zion Unit 1	29589025	12/18/89	MFDSGMT	2	Maintenance	Test	FTO	False	False	True
Zion Unit 1	29590002	01/16/90	TDP	2	Personnel	Test	FTR	False	False	False
Zion Unit 1	29592014	09/09/92	TDP	1	Maintenance	Test	FTR	False	False	False
Zion Unit 1	29592016	09/26/92	MDP	2	Design	Test	FTS	False	False	True
Zion Unit 1	29592020	10/21/92	MDP	1	Maintenance	Other	FTS	False	False	False
Zion Unit 1	29594008	06/10/94	MDP	2	Hardware	Test	FTR	False	True	False
Zion Unit 2	29588019	10/25/88	MDP	2	Design	Review	FTS	False	False	True
Zion Unit 2	29592016	09/26/92	MDP	2	Design	Other	FTS	False	False	True
Zion Unit 2	30488006	10/29/88	MDP	1	Design	Review	N/A	False	False	False
Zion Unit 2	30488015	12/19/88	TFDSGMT	4	Personnel	Other	N/A	False	False	False
Zion Unit 2	30491003	06/08/91	TDP	1	Personnel	Other	FTS	False	False	False
Zion Unit 2	30494002	03/07/94	TDP	1	Maintenance	Test	FTS	False	False	False
Zion Unit 2	30494004	04/07/94	MFDSGMT	1	Hardware	Test	FTO	False	False	False
Zion Unit 2	30494004	04/07/94	TFDSGMT	1	Maintenance	Test	FTO	False	False	False

Table B-3. Auxiliary feedwater unplanned demands.

Plant Name	LER Number	Event Date	Segment Demanded: Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Arkansas Unit 1	31387002	5/17/87	2	1	2	2	1	2	0	0	0	2
Arkansas Unit 1	31387003	8/8/87	2	1	2	2	1	2	0	0	0	2
Arkansas Unit 1	31387004	8/15/87	2	1	2	2	1	2	0	0	0	2
Arkansas Unit 1	31387005	8/25/87	2	1	2	2	1	2	0	0	0	2
Arkansas Unit 1	31388003	2/17/88	2	1	1	0	0	0	0	0	0	2
Arkansas Unit 1	31389002	1/20/89	2	1	1	2	1	1	0	0	0	2
Arkansas Unit 1	31389020	5/30/89	2	1	2	0	0	0	0	0	0	2
Arkansas Unit 1	31389041	12/21/89	2	1	2	0	0	0	0	0	0	2
Arkansas Unit 1	31389041	12/21/89	0	0	0	2	1	2	0	0	0	2
Arkansas Unit 1	31389048	12/28/89	2	1	2	2	1	2	0	0	0	2
Arkansas Unit 1	31391003	4/21/91	0	1	2	0	0	0	0	0	0	2
Arkansas Unit 1	31391003	4/21/91	2	0	0	2	1	2	0	0	0	2
Arkansas Unit 1	31391005	5/21/91	2	1	2	2	1	2	0	0	0	2
Arkansas Unit 1	31392003	4/24/92	2	1	2	2	1	2	0	0	0	2
Arkansas Unit 1	31394002	4/11/94	2	1	2	2	1	2	0	0	0	2
Arkansas Unit 1	31395004	4/3/95	2	1	2	2	1	2	0	0	0	2
Arkansas Unit 2	36887007	9/9/87	0	1	2	0	0	0	0	0	0	2
Arkansas Unit 2	36887007	9/9/87	3	0	0	2	1	2	0	0	0	2
Arkansas Unit 2	36887008	11/14/87	3	1	2	0	0	0	0	0	0	2
Arkansas Unit 2	36887008	11/14/87	0	0	0	2	1	2	0	0	0	2
Arkansas Unit 2	36888011	8/1/88	3	1	2	0	1	2	0	0	0	2
Arkansas Unit 2	36888020	12/1/88	3	1	2	2	1	2	0	0	0	2
Arkansas Unit 2	36889006	4/18/89	3	0	0	2	1	2	0	0	0	2
Arkansas Unit 2	36889006	4/18/89	0	1	2	0	0	0	0	0	0	2
Arkansas Unit 2	36889024	12/31/89	3	0	0	2	1	1	0	0	0	1
Arkansas Unit 2	36889024	12/31/89	0	1	0	2	1	0	0	0	0	1
Arkansas Unit 2	36890019	8/21/90	3	1	2	2	1	2	0	0	0	2
Arkansas Unit 2	36890020	9/28/90	3	1	2	2	1	2	0	0	0	2
Arkansas Unit 2	36891005	2/1/91	3	1	2	2	1	2	0	0	0	2
Beaver Valley Unit 1	33487002	2/7/87	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 1	33487013	6/9/87	0	0	0	3	1	0	0	0	6	3
Beaver Valley Unit 1	33488007	6/7/88	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 1	33488008	6/9/88	0	2	0	3	1	0	0	0	0	0
Beaver Valley Unit 1	33488008	6/9/88	0	2	0	0	0	0	0	0	6	3

Table B-3. (continued).

Plant Name	LER Number	Event Date	Segment Demanded: Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Beaver Valley Unit 1	33488009	6/11/88	0	2	0	0	0	0	0	0	0	3
Beaver Valley Unit 1	33488009	6/11/88	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 1	33489001	1/17/89	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 1	33489002	2/13/89	0	0	0	3	1	0	0	0	6	3
Beaver Valley Unit 1	33489007	5/18/89	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 1	33490007	3/30/90	0	0	0	3	1	0	0	0	6	3
Beaver Valley Unit 1	33491022	7/20/91	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 1	33491023	7/27/91	0	0	0	3	1	0	0	0	6	3
Beaver Valley Unit 1	33491029	11/6/91	0	0	0	3	1	0	0	0	6	3
Beaver Valley Unit 1	33492009	10/9/92	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 1	33493013	10/12/93	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 1	33494005	6/1/94	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 1	33494008	7/19/94	0	0	0	3	1	0	0	0	6	3
Beaver Valley Unit 2	33494005	6/1/94	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 2	41287005	7/17/87	0	2	0	3	1	0	0	0	3	3
Beaver Valley Unit 2	41287014	8/15/87	0	0	0	3	1	0	0	0	3	3
Beaver Valley Unit 2	41287015	8/15/87	0	0	0	3	1	0	0	0	3	3
Beaver Valley Unit 2	41287017	8/16/87	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 2	41287019	8/25/87	0	0	0	3	1	0	0	0	3	3
Beaver Valley Unit 2	41287020	9/9/87	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 2	41287023	9/28/87	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 2	41287024	9/29/87	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 2	41287025	9/30/87	0	2	0	0	0	0	0	0	6	3
Beaver Valley Unit 2	41287026	10/8/87	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 2	41287028	10/14/87	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 2	41287030	10/16/87	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 2	41287032	10/24/87	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 2	41287034	10/29/87	0	0	0	3	1	0	0	0	3	3
Beaver Valley Unit 2	41287035	11/10/87	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 2	41287036	11/17/87	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 2	41288002	1/27/88	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 2	41288007	4/4/88	0	0	0	3	1	0	0	0	3	3
Beaver Valley Unit 2	41288009	7/27/88	0	0	0	3	1	0	0	0	3	3
Beaver Valley Unit 2	41288011	8/23/88	0	0	0	3	1	0	0	0	3	3
Beaver Valley Unit 2	41288013	9/20/88	0	0	0	3	1	0	0	0	3	3
Beaver Valley Unit 2	41289003	2/12/89	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 2	41289019	6/22/89	0	0	0	3	1	0	0	0	3	3

Table B-3. (continued)

Plant Name	LER Number	Event Date	Segment Demanded									
			Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Beaver Valley Unit 2	41289020	6/22/89	0	2	0	0	0	0	0	0	6	3
Beaver Valley Unit 2	41290008	7/2/90	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 2	41291005	11/26/91	0	2	0	3	1	0	0	0	6	3
Beaver Valley Unit 2	41292007	5/5/92	0	2	0	0	0	0	0	0	6	3
Beaver Valley Unit 2	41292009	6/5/92	0	2	0	0	0	0	0	0	6	3
Beaver Valley Unit 2	41293002	1/30/93	0	0	0	3	1	0	0	0	3	3
Beaver Valley Unit 2	41293002	1/30/93	0	1	0	0	0	0	0	0	0	0
Beaver Valley Unit 2	41295006	8/13/95	0	2	0	3	1	0	0	0	6	3
Braidwood Unit 1	45687046	9/10/87	0	0	0	0	0	0	1	4	0	0
Braidwood Unit 1	45687060	12/6/87	0	1	4	0	0	0	0	0	0	0
Braidwood Unit 1	45687060	12/6/87	0	0	0	0	0	0	1	4	0	0
Braidwood Unit 1	45688016	8/11/88	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 1	45688022	10/16/88	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 1	45688025	11/15/88	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 1	45689004	3/6/89	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 1	45690001	1/12/90	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 1	45690008	6/8/90	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 1	45690021	12/1/90	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 1	45690023	12/30/90	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 1	45691012	11/6/91	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 1	45693001	1/7/93	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 1	45694012	8/11/94	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 1	45695004	4/9/95	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45688023	10/17/88	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45688025	11/15/88	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45788012	6/20/88	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45788013	6/21/88	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45788014	6/22/88	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45788016	6/24/88	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45788018	7/2/88	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45788019	7/24/88	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45788020	9/4/88	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45788028	11/17/88	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45788029	10/25/88	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45788031	11/5/88	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45789002	5/11/89	0	0	0	0	0	0	1	4	0	0

Table B-3. (continued).

Plant Name	LER Number	Event Date	Segment Demanded: Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Braidwood Unit 2	45789002	5/11/89	0	1	4	0	0	0	0	0	0	0
Braidwood Unit 2	45789004	9/7/89	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45790010	6/9/90	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45791003	8/1/91	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45791006	12/1/91	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45792001	2/25/92	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45792002	3/15/92	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45792006	9/10/92	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45792007	11/14/92	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45793007	10/3/93	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45794003	4/5/94	0	1	4	0	0	0	1	4	0	0
Braidwood Unit 2	45794005	8/2/94	0	1	4	0	0	0	1	4	0	0
Bryon Unit 1	45487018	8/11/87	0	1	4	0	0	0	1	4	0	0
Bryon Unit 1	45487019	8/12/87	0	1	4	0	0	0	1	4	0	0
Bryon Unit 1	45488002	4/18/88	0	0	0	0	0	0	1	4	0	0
Bryon Unit 1	45488002	4/18/88	0	1	4	0	0	0	0	0	0	0
Bryon Unit 1	45488004	7/16/88	0	0	0	0	0	0	1	4	0	0
Bryon Unit 1	45488004	7/16/88	0	1	4	0	0	0	0	0	0	0
Bryon Unit 1	45488005	8/4/88	0	0	0	0	0	0	1	4	0	0
Bryon Unit 1	45488005	8/4/88	0	1	4	0	0	0	0	0	0	0
Bryon Unit 1	45488005	8/4/88	0	1	4	0	0	0	0	0	0	0
Bryon Unit 1	45489002	1/31/89	0	1	4	0	0	0	1	4	0	0
Bryon Unit 1	45490006	5/3/90	0	1	4	0	0	0	1	4	0	0
Bryon Unit 1	45490011	8/19/90	0	1	4	0	0	0	1	4	0	0
Bryon Unit 1	45490014	12/3/90	0	1	4	0	0	0	1	4	0	0
Bryon Unit 1	45492001	1/29/92	0	1	4	0	0	0	1	4	0	0
Byron Unit 2	45587005	3/31/87	0	1	4	0	0	0	1	4	0	0
Byron Unit 2	45587006	4/27/87	0	1	4	0	0	0	1	4	0	0
Byron Unit 2	45587007	5/4/87	0	1	0	0	0	0	1	4	0	0
Byron Unit 2	45587009	6/29/87	0	1	4	0	0	0	1	4	0	0
Byron Unit 2	45587011	7/25/87	0	1	4	0	0	0	1	4	0	0
Byron Unit 2	45587018	10/1/87	0	1	4	0	0	0	1	4	0	0
Byron Unit 2	45588004	5/6/88	0	0	0	0	0	0	1	4	0	0
Byron Unit 2	45588004	5/6/88	0	1	4	0	0	0	0	0	0	0
Byron Unit 2	45588006	6/2/88	0	0	0	0	0	0	1	4	0	0
Byron Unit 2	45588006	6/2/88	0	1	4	0	0	0	0	0	0	0

Table B-3. (continued)

Plant Name	LER Number	Event Date	Segment Demanded									
			Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Byron Unit 2	45588008	7/14/88	0	0	0	0	0	0	1	4	0	0
Byron Unit 2	45588008	7/14/88	0	1	4	0	0	0	0	0	0	0
Byron Unit 2	45588009	7/15/88	0	1	4	0	0	0	0	0	0	0
Byron Unit 2	45588009	7/15/88	0	0	0	0	0	0	1	4	0	0
Byron Unit 2	45588012	12/15/88	0	1	4	0	0	0	1	4	0	0
Byron Unit 2	45590001	1/18/90	0	1	4	0	0	0	1	4	0	0
Byron Unit 2	45590010	12/20/90	0	1	4	0	0	0	1	4	0	0
Byron Unit 2	45591005	11/7/91	0	1	4	0	0	0	1	4	0	0
Byron Unit 2	45592003	6/10/92	0	1	4	0	0	0	1	4	0	0
Byron Unit 2	45593003	5/11/93	0	1	4	0	0	0	1	4	0	0
Byron Unit 2	45594003	9/24/94	0	0	0	0	0	0	1	4	0	0
Callaway	48387032	11/8/87	0	2	4	0	0	0	0	0	0	4
Callaway	48388001	1/4/88	0	2	4	0	0	0	0	0	0	4
Callaway	48388004	2/13/88	0	2	4	0	0	0	0	0	0	4
Callaway	48388005	4/16/88	0	2	4	0	0	0	0	0	0	4
Callaway	48388005	4/17/88	0	2	4	0	0	0	0	0	0	4
Callaway	48388006	4/21/88	0	2	4	0	0	0	0	0	0	4
Callaway	48388007	5/2/88	0	2	4	0	0	0	0	0	0	4
Callaway	48388010	9/3/88	0	2	4	0	0	0	0	0	0	4
Callaway	48388010	9/2/88	0	2	4	0	0	0	0	0	0	4
Callaway	48388015	11/16/88	0	1	2	0	0	0	0	0	0	2
Callaway	48389003	3/31/89	0	2	4	0	0	0	0	0	0	4
Callaway	48389005	5/18/89	0	2	4	0	0	0	0	0	0	4
Callaway	48389005	5/18/89	0	2	4	0	0	0	0	0	0	4
Callaway	48389006	5/29/89	0	2	4	0	0	0	0	0	0	4
Callaway	48389008	6/23/89	0	0	0	2	1	4	0	0	0	4
Callaway	48390005	5/1/90	0	2	4	0	0	0	0	0	0	4
Callaway	48390007	6/11/90	0	2	4	0	0	0	0	0	0	4
Callaway	48390015	11/19/90	0	2	4	2	1	4	0	0	0	4
Callaway	48390016	11/24/90	0	2	4	0	0	0	0	0	0	4
Callaway	48390017	12/30/90	0	2	4	0	0	0	0	0	0	4
Callaway	48391006	11/5/91	0	2	4	0	0	0	0	0	0	4
Callaway	48392002	1/22/92	0	2	4	0	0	0	0	0	0	4
Callaway	48392003	1/23/92	0	2	4	0	0	0	0	0	0	4
Callaway	48392004	3/20/92	0	2	4	0	0	0	0	0	0	4
Callaway	48392006	5/15/92	0	2	0	0	0	0	0	0	0	4

Table B-3. (continued).

			Segment Demanded									
Plant Name	LER Number	Event Date	Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Callaway	48392007	5/23/92	0	2	0	0	0	0	0	0	0	4
Callaway	48392010	9/20/92	0	2	4	2	1	4	0	0	0	4
Callaway	48395004	6/8/95	0	2	4	0	0	0	0	0	0	4
Callaway	48395005	8/16/95	0	2	4	0	0	0	0	0	0	4
Callaway	48395006	4/10/92	0	2	4	0	0	0	0	0	0	4
Calvert Cliffs Unit 1	31787003	1/27/87	0	1	2	2	1	2	0	0	0	2
Calvert Cliffs Unit 1	31787012	7/23/87	0	1	2	2	1	2	0	0	0	2
Calvert Cliffs Unit 1	31787015	11/11/87	0	1	2	0	0	0	0	0	0	2
Calvert Cliffs Unit 1	31788009	8/24/88	0	1	2	0	0	0	0	0	0	2
Calvert Cliffs Unit 1	31788012	11/14/88	0	1	2	2	1	2	0	0	0	2
Calvert Cliffs Unit 1	31791003	10/1/91	0	1	2	2	1	2	0	0	0	2
Calvert Cliffs Unit 1	31792008	11/24/92	0	0	0	2	1	2	0	0	0	0
Calvert Cliffs Unit 1	31792008	11/24/92	0	1	2	2	1	2	0	0	0	2
Calvert Cliffs Unit 1	31794001	1/24/94	0	1	2	2	1	2	0	0	0	2
Calvert Cliffs Unit 1	31794006	6/16/94	0	1	2	2	1	2	0	0	0	2
Calvert Cliffs Unit 1	31794007	7/19/94	0	1	2	0	0	0	0	0	2	
Calvert Cliffs Unit 1	31795002	6/16/95	0	1	2	2	1	2	0	0	0	2
Calvert Cliffs Unit 1	31795006	11/16/95	0	1	2	2	1	2	0	0	0	2
Calvert Cliffs Unit 2	31787012	7/23/87	0	1	2	2	1	2	0	0	0	2
Calvert Cliffs Unit 2	31887002	2/28/87	0	1	2	2	1	2	0	0	0	2
Calvert Cliffs Unit 2	31887006	9/7/87	0	1	2	0	0	0	0	0	0	2
Calvert Cliffs Unit 2	31887008	11/22/87	0	1	2	2	1	2	0	0	0	2
Calvert Cliffs Unit 2	31887009	12/21/87	0	1	2	2	1	2	0	0	0	2
Calvert Cliffs Unit 2	31888002	1/22/88	0	1	2	2	1	2	0	0	0	2
Calvert Cliffs Unit 2	31888004	4/27/88	0	1	2	2	1	2	0	0	0	2
Calvert Cliffs Unit 2	31892001	1/2/92	0	1	2	2	1	2	0	0	0	2
Calvert Cliffs Unit 2	31892003	6/24/92	0	1	2	2	1	2	0	0	0	2
Calvert Cliffs Unit 2	31892005	8/1/92	0	1	2	0	0	0	0	0	0	2
Calvert Cliffs Unit 2	31892006	8/17/92	0	1	2	0	0	0	0	0	0	2
Calvert Cliffs Unit 2	31892007	9/29/92	0	1	2	2	1	2	0	0	0	2
Calvert Cliffs Unit 2	31894001	1/12/94	0	1	2	2	1	2	0	0	0	2
Calvert Cliffs Unit 2	31895002	1/13/95	0	1	2	2	1	2	0	0	0	2
Calvert Cliffs Unit 2	31895003	1/15/95	0	1	2	0	0	0	0	0	0	2
Catawba Unit 1	41387006	1/31/87	3	2	4	0	0	0	0	0	0	0
Catawba Unit 1	41387013	3/16/87	3	2	4	0	0	0	0	0	0	0

Table B-3. (continued)

Plant Name	LER Number	Event Date	Segment Demanded: Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Catawba Unit 1	41387015	4/9/87	3	2	4	0	0	0	0	0	0	0
Catawba Unit 1	41387026	7/6/87	0	0	0	0	2	4	0	0	0	0
Catawba Unit 1	41387026	7/6/87	3	1	4	0	0	0	0	0	0	0
Catawba Unit 1	41387028	7/11/87	3	2	4	0	0	0	0	0	0	0
Catawba Unit 1	41387029	7/13/87	3	2	4	0	0	0	0	0	0	0
Catawba Unit 1	41387034	8/23/87	3	1	3	0	0	0	0	0	0	0
Catawba Unit 1	41388007	1/23/88	3	2	4	0	0	0	0	0	0	0
Catawba Unit 1	41389003	2/6/89	0	0	0	2	1	2	0	0	0	0
Catawba Unit 1	41389003	2/6/89	3	2	4	0	0	0	0	0	0	0
Catawba Unit 1	41389008	3/5/89	3	2	4	0	0	0	0	0	0	0
Catawba Unit 1	41389017	6/26/89	3	2	4	0	0	0	0	0	0	0
Catawba Unit 1	41389022	8/24/89	3	2	4	0	0	0	0	0	0	0
Catawba Unit 1	41391013	6/20/91	3	2	4	0	0	0	0	0	0	0
Catawba Unit 1	41391015	7/10/91	3	2	4	0	0	0	0	0	0	0
Catawba Unit 1	41391018	9/6/91	3	1	2	2	1	2	0	0	0	0
Catawba Unit 1	41391019	9/11/91	3	2	4	0	0	0	0	0	0	0
Catawba Unit 1	41391021	10/2/91	3	2	4	0	0	0	0	0	0	0
Catawba Unit 1	41392008	7/12/92	3	2	4	0	0	0	0	0	0	0
Catawba Unit 1	41393006	6/12/93	3	2	4	0	0	0	0	0	0	0
Catawba Unit 1	41393008	7/18/93	3	2	4	0	0	0	0	0	0	0
Catawba Unit 1	41393008	7/19/93	3	2	4	0	0	0	0	0	0	0
Catawba Unit 1	41394001	1/11/94	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41487002	1/28/87	3	2	4	2	1	2	0	0	0	0
Catawba Unit 2	41487003	1/30/87	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41487003	1/30/87	0	0	0	2	1	2	0	0	0	0
Catawba Unit 2	41487007	2/24/87	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41487007	2/24/87	0	0	0	2	1	2	0	0	0	0
Catawba Unit 2	41487010	3/23/87	0	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41487010	3/23/87	3	0	0	2	2	4	0	0	0	0
Catawba Unit 2	41487011	3/24/87	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41487013	3/25/87	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41487018	5/6/87	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41487018	5/6/87	0	0	0	2	1	2	0	0	0	0
Catawba Unit 2	41487019	5/8/87	0	0	0	2	1	2	0	0	0	0
Catawba Unit 2	41487019	5/8/87	3	1	2	0	0	0	0	0	0	0
Catawba Unit 2	41487019	5/8/87	3	1	2	0	0	0	0	0	0	0
Catawba Unit 2	41487021	7/27/87	3	0	0	0	2	4	0	0	0	0

Table B-3. (continued).

Plant Name	LER Number	Event Date	Segment Demanded: Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Catawba Unit 2	41487021	7/27/87	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41487022	7/28/87	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41487024	8/7/87	3	1	2	0	0	0	0	0	0	0
Catawba Unit 2	41487025	9/3/87	0	0	0	2	1	2	0	0	0	0
Catawba Unit 2	41487025	9/3/87	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41487027	9/15/87	3	1	2	0	0	0	0	0	0	0
Catawba Unit 2	41487027	9/15/87	0	0	0	2	1	2	0	0	0	0
Catawba Unit 2	41487027	9/15/87	3	1	2	0	0	0	0	0	0	0
Catawba Unit 2	41487029	11/3/87	3	2	4	2	1	2	0	0	0	0
Catawba Unit 2	41488007	2/22/88	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41488012	3/9/88	3	0	0	2	1	2	0	0	0	0
Catawba Unit 2	41488012	3/9/88	4	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41488014	3/17/88	4	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41488017	4/24/88	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41488019	5/27/88	0	0	0	2	1	2	0	0	0	0
Catawba Unit 2	41488019	5/27/88	3	2	0	0	0	0	0	0	0	0
Catawba Unit 2	41488020	5/28/88	3	1	2	0	0	0	0	0	0	0
Catawba Unit 2	41488020	5/28/88	3	1	2	0	0	0	0	0	0	0
Catawba Unit 2	41488021	6/3/88	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41488021	6/3/88	0	0	0	2	1	2	0	0	0	0
Catawba Unit 2	41488022	6/6/88	0	0	0	2	1	2	0	0	0	0
Catawba Unit 2	41488022	6/6/88	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41488023	6/20/88	0	0	0	2	1	2	0	0	0	0
Catawba Unit 2	41488023	6/20/88	0	1	2	0	0	0	0	0	0	0
Catawba Unit 2	41488023	6/20/88	3	1	2	0	0	0	0	0	0	0
Catawba Unit 2	41488025	6/26/88	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41488025	6/26/88	0	0	0	2	1	2	0	0	0	0
Catawba Unit 2	41488028	9/29/88	3	1	2	0	0	0	0	0	0	0
Catawba Unit 2	41488028	9/29/88	0	1	2	0	0	0	0	0	0	0
Catawba Unit 2	41488031	11/23/88	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41488031	11/23/88	0	0	0	2	1	2	0	0	0	0
Catawba Unit 2	41488032	11/24/88	3	1	2	0	0	0	0	0	0	0
Catawba Unit 2	41489001	1/12/89	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41489001	1/12/89	0	0	0	2	1	2	0	0	0	0
Catawba Unit 2	41489002	1/1/89	0	0	0	2	1	2	0	0	0	0
Catawba Unit 2	41489002	1/21/89	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41489003	2/21/89	0	0	0	2	1	2	0	0	0	0
Catawba Unit 2	41489003	2/21/89	3	2	4	0	0	0	0	0	0	0

Table B-3. (continued)

Plant Name	LER Number	Event Date	Segment Demanded									
			Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Catawba Unit 2	41489004	2/21/89	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41489015	6/9/89	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41490013	10/7/90	3	2	4	2	1	2	0	0	0	0
Catawba Unit 2	41491006	4/16/91	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41491008	5/29/91	3	2	4	2	1	2	0	0	0	0
Catawba Unit 2	41491012	10/17/91	3	1	4	0	0	0	0	0	0	0
Catawba Unit 2	41492001	1/15/92	3	2	4	2	1	2	0	0	0	0
Catawba Unit 2	41492006	12/14/92	3	2	4	2	1	2	0	0	0	0
Catawba Unit 2	41493003	9/25/93	0	0	0	2	1	2	0	0	0	0
Catawba Unit 2	41493003	9/25/93	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41494003	7/10/94	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41494005	8/30/94	3	2	4	0	0	0	0	0	0	0
Catawba Unit 2	41494006	9/13/94	3	2	4	2	1	2	0	0	0	0
Catawba Unit 2	41494007	10/18/94	3	2	4	2	1	2	0	0	0	0
Catawba Unit 2	41495001	2/21/95	3	2	4	4	2	2	0	0	0	0
Catawba Unit 2	41495004	4/27/95	3	2	4	2	1	2	0	0	0	0
Catawba Unit 2	41495005	5/1/95	3	2	4	0	0	0	0	0	0	0
Comanche Peak Unit 1	44590004	3/12/90	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44590009	4/21/90	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44590013	5/9/90	0	2	4	2	1	4	0	0	0	4
Comanche Peak Unit 1	44590017	5/27/90	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44590020	7/26/90	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44590021	7/30/90	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44590023	8/8/90	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44590025	8/25/90	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44590027	9/7/90	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44590027	9/7/90	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44590028	9/8/90	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44590029	9/10/90	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44590030	9/15/90	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44591002	1/23/91	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44591004	2/10/91	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44591008	3/17/91	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44591019	6/9/91	0	2	4	2	1	4	0	0	0	4
Comanche Peak Unit 1	44591020	7/13/91	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44591021	7/28/91	0	2	4	2	1	4	0	0	0	4
Comanche Peak Unit 1	44591022	9/4/91	0	2	4	2	1	4	0	0	0	4

Table B-3. (continued).

Plant Name	LER Number	Event Date	Segment Demanded: Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Comanche Peak Unit 1	44591023	10/3/91	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44592001	1/8/92	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44592009	5/8/92	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44592014	6/11/92	0	2	4	2	1	4	0	0	0	4
Comanche Peak Unit 1	44592016	6/23/92	0	2	4	2	1	4	0	0	0	4
Comanche Peak Unit 1	44592019	7/20/92	0	2	4	2	1	4	0	0	0	4
Comanche Peak Unit 1	44592022	10/12/92	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44593001	1/18/93	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44593002	1/24/93	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44593007	6/26/93	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44595002	6/5/95	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 1	44595003	6/11/95	0	2	4	2	1	4	0	0	0	4
Comanche Peak Unit 1	44595007	4/13/91	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 2	44693003	5/4/93	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 2	44693008	10/1/93	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 2	44693011	11/17/93	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 2	44694003	3/5/94	0	2	4	2	1	4	0	0	0	4
Comanche Peak Unit 2	44694010	6/27/94	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 2	44694012	8/15/94	0	2	4	0	0	0	0	0	0	4
Comanche Peak Unit 2	44695004	12/5/95	0	2	4	0	0	0	0	0	0	4
Cook Unit 1	31587008	6/4/87	0	2	4	2	1	4	0	0	0	0
Cook Unit 1	31587021	10/13/87	0	2	4	2	1	4	0	0	0	0
Cook Unit 1	31588001	1/13/88	0	2	4	2	1	4	0	0	0	0
Cook Unit 1	31588011	10/19/88	0	2	4	0	0	0	0	0	0	0
Cook Unit 1	31588013	11/23/88	0	2	4	0	0	0	0	0	0	0
Cook Unit 1	31589001	1/16/89	0	2	4	2	1	4	0	0	0	0
Cook Unit 1	31589003	3/18/89	0	2	4	0	0	0	0	0	0	0
Cook Unit 1	31591004	5/12/91	0	2	4	2	1	4	0	0	0	0
Cook Unit 1	31595003	7/14/95	0	2	4	0	0	0	0	0	0	0
Cook Unit 2	31687004	6/1/87	0	2	4	2	1	4	0	0	0	0
Cook Unit 2	31687005	6/2/87	0	2	4	0	0	0	0	0	0	0
Cook Unit 2	31687007	7/14/87	0	2	4	2	1	4	0	0	0	0
Cook Unit 2	31687008	7/22/87	0	2	4	2	1	4	0	0	0	0
Cook Unit 2	31689014	8/14/89	0	2	4	0	0	0	0	0	0	0
Cook Unit 2	31690004	6/11/90	0	2	4	0	0	0	0	0	0	0
Cook Unit 2	31690012	12/12/90	0	2	4	2	1	4	0	0	0	0

Table B-3. (continued)

			Segment Demanded									
Plant Name	LER Number	Event Date	Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Cook Unit 2	31690013	12/15/90	0	2	4	2	1	4	0	0	0	0
Cook Unit 2	31691004	3/13/91	0	2	4	2	1	0	0	0	0	0
Cook Unit 2	31691006	8/1/91	0	2	4	2	1	4	0	0	0	0
Cook Unit 2	31691010	11/15/91	0	2	4	2	1	4	0	0	0	0
Cook Unit 2	31693007	8/2/93	0	2	4	2	1	4	0	0	0	0
Cook Unit 2	31694001	2/21/94	0	2	4	0	0	0	0	0	0	0
Cook Unit 2	31694005	8/15/94	0	2	4	0	0	0	0	0	0	0
Cook Unit 2	31694008	12/11/94	0	2	4	0	0	0	0	0	0	0
Cook Unit 2	31695002	2/23/95	0	2	4	0	0	0	0	0	0	0
Cook Unit 2	31695004	8/26/95	0	2	4	0	0	0	0	0	0	0
Cook Unit 2	31695005	8/29/95	0	1	2	0	0	0	0	0	0	0
Cook Unit 2	31695005	8/29/95	0	1	2	0	0	0	0	0	0	0
Crystal River 3	30288001	1/9/88	0	0	0	2	1	2	0	0	0	2
Crystal River 3	30288001	1/7/88	0	0	0	2	1	2	0	0	0	2
Crystal River 3	30288002	1/7/88	0	1	2	2	1	2	0	0	0	2
Crystal River 3	30288006	2/28/88	0	1	2	2	1	2	0	0	0	2
Crystal River 3	30288024	10/28/88	0	1	2	2	1	2	0	0	0	2
Crystal River 3	30289003	1/15/89	0	1	2	2	1	2	0	0	0	2
Crystal River 3	30289022	6/14/89	0	1	2	2	1	2	0	0	0	2
Crystal River 3	30289023	6/16/89	0	1	2	2	1	2	0	0	0	2
Crystal River 3	30289025	6/29/89	0	1	2	0	0	0	0	0	0	2
Crystal River 3	30290016	10/10/90	0	1	2	2	1	2	0	0	0	2
Crystal River 3	30291003	4/20/91	0	1	2	2	1	2	0	0	0	2
Crystal River 3	30291014	11/25/91	0	1	2	2	1	2	0	0	0	2
Crystal River 3	30291016	11/25/91	0	1	2	2	1	2	0	0	0	2
Crystal River 3	30291018	12/8/91	0	1	2	2	1	2	0	0	0	2
Crystal River 3	30292001	3/27/92	0	1	2	0	0	0	0	0	0	2
Crystal River 3	30292015	7/17/92	0	1	2	2	1	2	0	0	0	2
Crystal River 3	30292027	12/29/92	0	1	2	2	1	2	0	0	0	2
Crystal River 3	30293009	9/18/93	0	1	2	2	1	2	0	0	0	2
Davis-Besse	34687006	3/13/87	1	0	0	2	2	4	0	0	0	2
Davis-Besse	34687011	9/6/87	1	0	0	2	2	4	0	0	0	2
Davis-Besse	34691008	12/10/91	1	0	0	2	2	4	0	0	0	2
Davis-Besse	34693005	10/8/93	1	0	0	2	2	4	0	0	0	2

Table B-3. (continued).

			Segment Demanded									
Plant Name	LER Number	Event Date	Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Diablo Canyon Unit 1	27587004	3/15/87	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 1	27587006	5/11/87	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 1	27587023	12/13/87	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 1	27587024	12/13/87	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 1	27588002	1/8/88	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 1	27588025	8/30/88	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 1	27589009	10/6/89	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 1	27589015	12/14/89	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 1	27589015	12/14/89	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 1	27590002	2/20/90	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 1	27590005	6/14/90	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 1	27590014	12/5/90	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 1	27590017	12/24/90	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 1	27591002	2/1/91	0	2	4	2	1	4	0	0	0	4
Diablo Canyon Unit 1	27591007	4/23/91	0	2	4	2	1	4	0	0	0	4
Diablo Canyon Unit 1	27591009	5/17/91	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 1	27592002	3/6/92	0	2	4	2	1	4	0	0	0	4
Diablo Canyon Unit 1	27592004	4/25/92	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 1	27593011	12/26/93	0	2	4	2	1	4	0	0	0	4
Diablo Canyon Unit 1	27594020	12/14/94	0	2	4	2	1	4	0	0	0	4
Diablo Canyon Unit 1	27595009	9/6/95	0	2	4	2	1	4	0	0	0	4
Diablo Canyon Unit 1	27595015	11/28/95	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 1	27595017	12/13/95	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 2	27594020	12/14/94	0	2	4	2	1	4	0	0	0	4
Diablo Canyon Unit 2	32387003	3/21/87	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 2	32387004	4/3/87	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 2	32387013	7/1/87	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 2	32387016	7/14/87	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 2	32387024	11/7/87	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 2	32388002	3/3/88	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 2	32388008	7/17/88	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 2	32389005	4/16/89	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 2	32389007	7/16/89	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 2	32389008	8/28/89	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 2	32389010	10/27/89	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 2	32393001	1/30/93	0	2	4	0	0	0	0	0	0	4

Table B-3. (continued)

Plant Name	LER Number	Event Date	Segment Demanded: Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Diablo Canyon Unit 2	32394012	12/19/94	0	2	4	0	0	0	0	0	0	4
Diablo Canyon Unit 2	32395002	9/23/95	0	2	4	0	0	0	0	0	0	4
Farley Unit 1	34887002	1/8/87	0	2	3	0	0	0	0	0	0	3
Farley Unit 1	34887003	1/9/87	0	2	3	0	0	0	0	0	0	3
Farley Unit 1	34887004	1/22/87	0	2	3	0	0	0	0	0	0	3
Farley Unit 1	34887010	5/14/87	0	2	3	2	1	3	0	0	0	3
Farley Unit 1	34888021	10/21/88	0	2	3	0	0	0	0	0	0	3
Farley Unit 1	34889006	11/12/89	0	2	3	2	1	3	0	0	0	3
Farley Unit 1	34889007	11/12/89	0	2	3	2	1	3	0	0	0	3
Farley Unit 1	34890005	7/20/90	0	2	3	0	0	0	0	0	0	3
Farley Unit 1	34891006	5/24/91	0	2	3	0	0	0	0	0	0	3
Farley Unit 1	34891007	6/29/91	0	2	3	0	0	0	0	0	0	3
Farley Unit 1	34891008	8/2/91	0	2	3	0	0	0	0	0	0	3
Farley Unit 1	34891009	8/19/91	0	2	3	0	0	0	0	0	0	3
Farley Unit 1	34891010	10/3/91	0	2	3	2	1	3	0	0	0	3
Farley Unit 1	34892008	12/13/92	0	2	3	2	1	3	0	0	0	3
Farley Unit 1	34895001	1/13/95	0	2	3	0	0	0	0	0	0	0
Farley Unit 1	34895005	6/11/95	0	2	3	0	0	0	0	0	0	3
Farley Unit 1	34895010	11/5/95	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36487001	2/28/87	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36487009	12/3/87	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36489007	5/22/89	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36489008	5/27/89	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36489010	9/20/89	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36489012	10/18/89	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36489013	10/19/89	0	0	3	0	0	0	0	0	0	3
Farley Unit 2	36489015	11/18/89	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36490001	5/12/90	0	2	3	2	1	3	0	0	0	3
Farley Unit 2	36491001	4/1/91	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36491002	4/9/91	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36491004	4/20/91	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36491005	8/6/91	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36492001	1/22/92	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36492002	3/6/92	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36492005	5/12/92	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36492006	5/15/92	0	2	3	0	0	0	0	0	0	3

Table B-3. (continued).

			Segment Demanded									
Plant Name	LER Number	Event Date	Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Farley Unit 2	36492007	5/25/92	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36492008	5/26/92	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36492010	10/20/92	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36493004	12/2/93	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36494001	8/5/94	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36494003	12/18/94	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36494004	12/25/94	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36494004	1/13/95	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36495005	6/1/95	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36495007	6/25/95	0	2	3	0	0	0	0	0	0	3
Farley Unit 2	36495008	11/28/95	0	2	3	0	0	0	0	0	0	3
Fort Calhoun	28590026	11/19/90	0	1	0	0	0	0	0	0	2	0
Fort Calhoun	28592023	7/3/92	0	1	0	0	0	0	0	0	2	0
Fort Calhoun	28592023	7/3/92	0	0	0	2	1	0	0	0	0	0
Fort Calhoun	28593011	6/24/93	0	1	0	0	0	0	0	0	2	0
Fort Calhoun	28593018	12/6/93	0	1	0	0	0	0	0	0	2	0
Fort Calhoun	28594001	2/11/94	0	1	0	2	1	0	0	0	2	0
Ginna	24488003	3/10/88	0	2	2	0	0	0	0	0	0	0
Ginna	24488005	6/1/88	0	2	2	2	1	2	0	0	0	0
Ginna	24488006	7/16/88	0	2	2	2	1	2	0	0	0	0
Ginna	24489004	6/1/89	0	2	2	2	1	2	0	0	0	0
Ginna	24490007	5/10/90	0	2	2	0	0	0	0	0	0	0
Ginna	24490010	6/9/90	0	2	2	0	0	0	0	0	0	0
Ginna	24490012	9/26/90	0	2	2	2	1	2	0	0	0	0
Ginna	24490013	12/11/90	0	1	1	0	0	0	0	0	0	0
Ginna	24490013	12/11/90	0	0	0	2	1	2	0	0	0	0
Ginna	24490013	12/11/90	0	1	1	0	0	0	0	0	0	0
Ginna	24490018	12/20/90	0	2	2	0	0	0	0	0	0	0
Ginna	24490019	12/21/90	0	2	2	0	0	0	0	0	0	0
Ginna	24492002	2/3/92	0	2	2	2	1	2	0	0	0	0
Ginna	24492003	2/29/92	0	2	2	2	1	2	0	0	0	0
Ginna	24493006	11/10/93	0	2	2	0	0	0	0	0	0	0
Ginna	24494007	4/27/94	0	2	2	2	1	2	0	0	0	0

Table B-3. (continued)

			Segment Demanded									
Plant Name	LER Number	Event Date	Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Haddam Neck	21390018	9/3/90	0	0	0	2	2	0	0	0	4	0
Haddam Neck	21394018	7/11/94	0	0	0	2	2	0	0	0	4	0
Haddam Neck	21395016	7/27/95	0	0	0	2	2	0	0	0	4	0
Harris	40087005	1/22/87	0	2	3	0	0	0	0	0	0	3
Harris	40087008	2/27/87	0	2	3	2	1	3	0	0	0	3
Harris	40087012	3/11/87	0	2	3	0	0	0	0	0	0	3
Harris	40087013	3/13/87	0	2	3	0	0	0	0	0	0	3
Harris	40087017	3/31/87	0	2	3	2	1	3	0	0	0	3
Harris	40087018	4/3/87	0	2	3	0	0	0	0	0	0	3
Harris	40087019	4/12/87	0	2	3	0	0	0	0	0	0	3
Harris	40087021	4/14/87	0	2	3	0	0	0	0	0	0	3
Harris	40087024	4/21/87	0	2	3	0	0	0	0	0	0	3
Harris	40087025	4/22/87	0	2	3	2	1	3	0	0	0	3
Harris	40087026	4/24/87	0	2	3	0	0	0	0	0	0	3
Harris	40087026	4/23/87	0	2	3	0	0	0	0	0	0	3
Harris	40087028	5/2/87	0	2	3	0	0	0	0	0	0	3
Harris	40087031	5/24/87	0	2	3	2	1	3	0	0	0	3
Harris	40087035	6/17/87	0	2	3	2	1	3	0	0	0	3
Harris	40087037	6/21/87	0	2	3	0	0	0	0	0	0	3
Harris	40087038	6/22/87	0	2	3	0	0	0	0	0	0	3
Harris	40087041	8/4/87	0	2	3	0	0	0	0	0	0	3
Harris	40087042	7/9/87	0	2	3	0	0	0	0	0	0	3
Harris	40087046	7/22/87	0	2	3	0	0	0	0	0	0	3
Harris	40087047	8/4/87	0	2	3	0	0	0	0	0	0	3
Harris	40087047	8/5/87	0	2	3	0	0	0	0	0	0	3
Harris	40087047	8/4/87	0	1	0	0	0	0	0	0	0	0
Harris	40087047	8/5/87	0	2	3	0	0	0	0	0	0	3
Harris	40087049	9/25/87	0	2	3	0	0	0	0	0	0	3
Harris	40087051	8/31/87	0	2	3	0	0	0	0	0	0	3
Harris	40087051	8/31/87	0	2	3	0	0	0	0	0	0	3
Harris	40087062	11/7/87	0	2	3	0	0	0	0	0	0	3
Harris	40087063	11/8/87	0	2	3	0	0	0	0	0	0	3
Harris	40088007	3/9/88	0	2	3	0	0	0	0	0	0	3
Harris	40088018	7/30/88	0	1	0	0	0	0	0	0	0	0
Harris	40088018	7/30/88	0	1	3	0	0	0	0	0	0	3
Harris	40088028	10/14/88	0	1	3	0	0	0	0	0	0	3
Harris	40088032	10/30/88	0	2	3	0	0	0	0	0	0	3

Table B-3. (continued).

Plant Name	LER Number	Event Date	Segment Demanded									
			Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Harris	40089001	1/16/89	0	2	3	2	1	3	0	0	0	3
Harris	40089003	2/6/89	0	3	3	2	1	3	0	0	0	3
Harris	40089004	2/7/89	0	2	3	0	0	0	0	0	0	3
Harris	40089005	2/22/89	0	2	3	2	1	3	0	0	0	3
Harris	40089006	3/14/89	0	2	3	0	1	0	0	0	0	3
Harris	40089017	10/9/89	0	2	3	2	1	3	0	0	0	3
Harris	40089021	12/27/89	0	2	3	2	1	3	0	0	0	3
Harris	40091009	5/21/91	0	2	3	0	0	0	0	0	0	3
Harris	40091010	6/3/91	0	2	3	2	1	3	0	0	0	3
Harris	40091015	5/19/91	0	2	3	0	0	0	0	0	0	3
Harris	40092007	7/12/92	0	2	3	0	0	0	0	0	0	3
Harris	40092008	7/13/92	0	2	3	0	0	0	0	0	0	3
Harris	40092009	7/15/92	0	2	3	0	0	0	0	0	0	3
Harris	40092010	7/17/92	0	2	3	2	1	3	0	0	0	3
Harris	40093007	5/23/93	0	1	3	2	1	3	0	0	0	3
Harris	40095010	10/12/95	0	2	3	0	0	0	0	0	0	3
Harris	40095011	11/5/95	0	2	3	2	1	3	0	0	0	3
Indian Pt. Unit 2	24788018	11/22/88	1	2	4	0	0	0	0	0	0	4
Indian Pt. Unit 2	24788019	11/26/88	1	2	4	0	0	0	0	0	0	4
Indian Pt. Unit 2	24789003	3/5/89	1	2	4	0	0	0	0	0	0	4
Indian Pt. Unit 2	24789013	12/13/89	1	2	4	0	0	0	0	0	0	4
Indian Pt. Unit 2	24791001	1/7/91	1	2	4	2	1	4	0	0	0	4
Indian Pt. Unit 2	24791013	7/25/91	1	2	4	0	0	0	0	0	0	4
Indian Pt. Unit 2	24792002	1/27/92	1	2	4	0	0	0	0	0	0	4
Indian Pt. Unit 2	24792007	4/13/92	1	2	4	0	0	0	0	0	0	4
Indian Pt. Unit 2	24792018	9/26/92	1	2	4	0	0	0	0	0	0	4
Indian Pt. Unit 2	24795001	1/17/95	1	2	4	0	0	0	0	0	0	4
Indian Pt. Unit 2	24795001	1/19/95	1	2	4	0	0	0	0	0	0	4
Indian Pt. Unit 2	24795016	6/12/95	1	2	4	0	0	0	0	0	0	4
Indian Pt. Unit 3	28687001	1/31/87	0	2	4	0	0	0	0	0	0	4
Indian Pt. Unit 3	28687012	12/22/87	0	2	4	0	0	0	0	0	0	4
Indian Pt. Unit 3	28688001	2/1/88	0	2	4	2	1	4	0	0	0	4
Indian Pt. Unit 3	28688002	3/31/88	0	2	4	0	0	0	0	0	0	4
Indian Pt. Unit 3	28688005	6/12/88	0	2	4	0	0	0	0	0	0	4
Indian Pt. Unit 3	28688006	10/9/88	0	2	4	2	1	4	0	0	0	4
Indian Pt. Unit 3	28689001	2/4/89	0	2	4	0	0	0	0	0	0	4

Table B-3. (continued)

Plant Name	LER Number	Event Date	Segment Demanded: Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Indian Pt. Unit 3	28689015	10/19/89	0	2	4	2	1	4	0	0	0	4
Indian Pt. Unit 3	28690004	6/29/90	0	2	4	2	1	4	0	0	0	4
Indian Pt. Unit 3	28691003	12/27/90	0	2	4	0	0	0	0	0	0	4
Indian Pt. Unit 3	28691004	3/20/91	0	2	4	2	1	4	0	0	0	4
Indian Pt. Unit 3	28691005	3/22/91	0	2	4	0	0	0	0	0	0	4
Indian Pt. Unit 3	28692013	9/3/92	0	2	4	0	0	0	0	0	0	4
Indian Pt. Unit 3	28692015	9/15/92	0	2	4	2	1	4	0	0	0	4
Indian Pt. Unit 3	28695012	7/6/95	0	2	4	0	0	0	0	0	0	4
Indian Pt. Unit 3	28695018	9/14/95	0	2	4	0	0	0	0	0	0	4
Kewaunee	30587005	4/3/87	0	2	0	0	0	0	0	0	0	2
Kewaunee	30587008	6/26/87	0	2	0	0	0	0	0	0	0	2
Kewaunee	30587009	7/10/87	0	2	0	0	0	0	0	0	0	2
Kewaunee	30588001	3/2/88	0	2	0	0	0	0	0	0	0	2
Kewaunee	30588004	4/12/88	0	2	0	0	0	0	0	0	0	2
Kewaunee	30588006	5/2/88	0	2	0	0	0	0	0	0	0	2
Kewaunee	30588012	9/1/88	0	2	0	0	0	0	0	0	0	2
Kewaunee	30589016	12/27/89	0	2	0	0	0	0	0	0	0	2
Kewaunee	30591010	10/12/91	0	2	0	2	1	0	0	0	0	2
Kewaunee	30592017	9/15/92	0	2	0	2	1	0	0	0	0	2
Kewaunee	30593001	1/28/93	0	2	0	2	1	0	0	0	0	2
Kewaunee	30593013	6/4/93	0	2	0	0	0	0	0	0	0	2
Kewaunee	30595005	9/5/95	0	2	0	0	0	0	0	0	0	2
Maine Yankee	30987006	6/27/87	0	2	0	0	0	0	0	0	3	0
Maine Yankee	30988001	1/5/88	0	2	0	0	0	0	0	0	3	0
Maine Yankee	30988006	8/13/88	0	2	0	0	0	0	0	0	3	0
Maine Yankee	30989001	1/10/89	0	2	0	0	0	0	0	0	3	0
Maine Yankee	30989003	4/5/89	0	2	0	0	0	0	0	0	3	0
Maine Yankee	30991005	4/29/91	0	2	0	0	0	0	0	0	3	0
Maine Yankee	30991006	5/30/91	0	1	0	0	0	0	0	0	3	0
Maine Yankee	30991010	10/5/91	0	2	0	0	0	0	0	0	3	0
Maine Yankee	30991012	11/22/91	0	2	0	0	0	0	0	0	3	0
Maine Yankee	30992001	2/8/92	0	2	0	0	0	0	0	0	3	0
Maine Yankee	30994008	5/18/94	0	2	0	0	0	0	0	0	3	0
Maine Yankee	30995001	1/14/95	0	2	0	0	0	0	0	0	3	0

Table B-3. (continued).

Plant Name	LER Number	Event Date	Segment Demanded: Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
McGuire Unit 1	36987009	4/15/87	3	2	4	0	1	0	0	0	0	0
McGuire Unit 1	36987017	8/16/87	3	2	4	2	1	4	0	0	0	0
McGuire Unit 1	36987019	9/4/87	3	2	4	0	0	0	0	0	0	0
McGuire Unit 1	36987028	11/20/87	3	1	2	0	0	0	0	0	0	0
McGuire Unit 1	36987036	12/28/87	3	2	4	0	0	0	0	0	0	0
McGuire Unit 1	36988001	1/7/88	3	2	4	0	0	0	0	0	0	0
McGuire Unit 1	36988005	3/23/88	3	2	4	0	0	0	0	0	0	0
McGuire Unit 1	36988007	4/16/88	3	2	4	2	1	0	0	0	0	0
McGuire Unit 1	36988013	6/20/88	3	2	4	0	0	0	0	0	0	0
McGuire Unit 1	36988015	6/26/88	3	2	4	0	0	0	0	0	0	0
McGuire Unit 1	36988042	12/10/88	3	2	4	0	0	0	0	0	0	0
McGuire Unit 1	36989022	8/26/89	3	2	4	0	0	0	0	0	0	0
McGuire Unit 1	36990001	1/8/90	3	2	4	0	0	0	0	0	0	0
McGuire Unit 1	36990027	10/13/90	3	2	4	0	0	0	0	0	0	0
McGuire Unit 1	36990032	11/17/90	3	2	4	0	0	0	0	0	0	0
McGuire Unit 1	36991001	2/11/91	0	0	0	2	1	4	0	0	0	0
McGuire Unit 1	36991001	2/11/91	3	2	4	0	0	0	0	0	0	0
McGuire Unit 1	36991004	2/19/91	3	2	4	0	0	0	0	0	0	0
McGuire Unit 1	36992008	7/26/92	3	2	4	2	1	4	0	0	0	0
McGuire Unit 1	36992009	6/25/92	3	2	4	2	1	4	0	0	0	0
McGuire Unit 1	36994004	5/12/94	3	2	4	0	0	0	0	0	0	0
McGuire Unit 1	36995001	1/29/95	3	2	4	0	0	0	0	0	0	0
McGuire Unit 1	36995005	9/27/95	3	2	2	2	1	4	0	0	0	0
McGuire Unit 1	36995006	10/1/95	3	2	4	0	0	0	0	0	0	0
McGuire Unit 2	37087003	1/20/87	3	2	4	0	0	0	0	0	0	0
McGuire Unit 2	37087016	9/6/87	3	2	4	0	0	0	0	0	0	0
McGuire Unit 2	37087019	11/5/87	3	2	4	2	1	4	0	0	0	0
McGuire Unit 2	37087021	11/30/87	3	2	4	0	0	0	0	0	0	0
McGuire Unit 2	37088001	1/12/88	3	2	4	0	0	0	0	0	0	0
McGuire Unit 2	37088008	7/31/88	3	2	4	0	0	0	0	0	0	0
McGuire Unit 2	37089001	3/3/89	3	2	4	0	0	0	0	0	0	0
McGuire Unit 2	37089002	3/14/89	3	2	4	2	1	4	0	0	0	0
McGuire Unit 2	37089003	4/6/89	3	2	4	0	0	0	0	0	0	0
McGuire Unit 2	37091007	7/12/91	3	2	4	0	0	0	0	0	0	0
McGuire Unit 2	37091010	9/25/91	3	2	4	0	0	0	0	0	0	0
McGuire Unit 2	37091011	10/4/91	3	2	4	0	0	0	0	0	0	0
McGuire Unit 2	37091012	11/8/91	3	2	4	0	0	0	0	0	0	0

Table B-3. (continued)

Plant Name	LER Number	Event Date	Segment Demanded: Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
McGuire Unit 2	37092004	3/21/92	3	2	4	0	0	0	0	0	0	0
McGuire Unit 2	37092006	4/9/92	3	2	4	2	1	4	0	0	0	0
McGuire Unit 2	37092007	5/20/92	3	2	4	0	0	0	0	0	0	0
McGuire Unit 2	37092009	8/5/92	3	2	4	0	0	0	0	0	0	0
McGuire Unit 2	37092010	8/24/92	3	2	4	0	0	0	0	0	0	0
McGuire Unit 2	37093001	2/22/93	3	2	4	0	0	0	0	0	0	0
McGuire Unit 2	37093002	3/9/93	3	2	4	0	0	0	0	0	0	0
McGuire Unit 2	37093008	12/27/93	3	2	4	2	1	4	0	0	0	0
McGuire Unit 2	37095004	12/16/95	3	2	4	0	0	0	0	0	0	0
Millstone Unit 2	33687009	9/2/87	0	2	0	0	0	0	0	0	2	0
Millstone Unit 2	33687012	11/16/87	0	2	0	0	0	0	0	0	2	0
Millstone Unit 2	33691012	11/6/91	0	2	0	0	0	0	0	0	2	0
Millstone Unit 2	33693012	5/24/93	0	2	0	0	0	0	0	0	2	0
Millstone Unit 2	33693019	8/12/93	0	1	0	0	0	0	0	0	0	0
Millstone Unit 2	33695002	8/8/95	0	2	0	0	0	0	0	0	2	0
Millstone Unit 3	42387001	1/13/87	0	2	4	0	0	0	0	0	0	0
Millstone Unit 3	42387008	3/7/87	0	2	4	0	0	0	0	0	0	0
Millstone Unit 3	42387020	4/12/87	0	2	4	0	0	0	0	0	0	0
Millstone Unit 3	42387021	4/12/87	0	1	2	0	0	0	0	0	0	0
Millstone Unit 3	42387025	5/7/87	0	2	4	0	0	0	0	0	0	0
Millstone Unit 3	42387026	5/14/87	0	2	2	3	1	4	0	0	0	0
Millstone Unit 3	42387027	6/5/87	0	2	4	3	1	4	0	0	0	0
Millstone Unit 3	42387031	6/14/87	0	2	4	3	1	4	0	0	0	0
Millstone Unit 3	42387034	9/23/87	0	2	4	3	1	4	0	0	0	0
Millstone Unit 3	42388009	2/10/88	0	2	4	0	0	0	0	0	0	0
Millstone Unit 3	42388023	10/5/88	0	2	4	0	0	0	0	0	0	0
Millstone Unit 3	42388024	10/22/88	0	2	4	0	0	0	0	0	0	0
Millstone Unit 3	42388028	12/29/88	0	2	4	0	0	0	0	0	0	0
Millstone Unit 3	42389008	5/6/89	0	2	4	0	0	0	0	0	0	0
Millstone Unit 3	42389009	5/11/89	0	2	4	0	1	0	0	0	0	0
Millstone Unit 3	42390005	1/18/90	0	2	4	3	1	4	0	0	0	0
Millstone Unit 3	42390009	3/9/90	0	2	4	0	0	0	0	0	0	0
Millstone Unit 3	42390011	3/30/90	0	2	4	0	0	0	0	0	0	0
Millstone Unit 3	42390013	4/16/90	0	2	4	0	0	0	0	0	0	0
Millstone Unit 3	42390014	5/19/90	0	2	4	0	0	0	0	0	0	0
Millstone Unit 3	42390019	6/6/90	0	2	4	0	0	0	0	0	0	0
Millstone Unit 3	42390030	12/31/90	0	2	4	3	1	4	0	0	0	0
Millstone Unit 3	42391014	6/9/91	0	2	4	0	0	0	0	0	0	0

Table B-3. (continued).

Plant Name	LER Number	Event Date	Segment Demanded: Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Millstone Unit 3	42392011	4/5/92	0	2	4	0	0	0	0	0	0	0
Millstone Unit 3	42392029	11/20/92	0	2	4	0	0	0	0	0	0	0
Millstone Unit 3	42393004	3/31/93	0	2	4	3	1	4	0	0	0	0
Millstone Unit 3	42394011	9/8/94	0	2	4	3	1	0	0	0	0	0
Millstone Unit 3	42395022	4/16/95	0	2	4	0	0	0	0	0	0	0
North Anna Unit 1	33887004	4/19/87	0	2	2	2	1	1	0	0	0	3
North Anna Unit 1	33887017	7/15/87	0	2	2	2	1	1	0	0	0	3
North Anna Unit 1	33887020	11/23/87	0	2	2	2	1	1	0	0	0	3
North Anna Unit 1	33888002	1/8/88	0	0	0	2	1	1	0	0	0	1
North Anna Unit 1	33888002	1/8/88	0	2	2	0	0	0	0	0	0	2
North Anna Unit 1	33888005	1/13/88	0	2	2	2	1	1	0	0	0	3
North Anna Unit 1	33888020	8/6/88	0	2	2	2	1	1	0	0	0	3
North Anna Unit 1	33889005	2/25/89	0	2	2	2	1	1	0	0	0	3
North Anna Unit 1	33889017	12/5/89	0	2	2	2	1	1	0	0	0	3
North Anna Unit 1	33894005	9/9/94	0	2	2	2	1	1	0	0	0	3
North Anna Unit 1	33895001	1/27/95	0	2	2	2	1	1	0	0	0	3
North Anna Unit 2	33990003	8/21/90	0	2	2	2	1	1	0	0	0	3
North Anna Unit 2	33990010	11/2/90	0	2	2	2	1	1	0	0	0	3
North Anna Unit 2	33991009	9/20/91	0	2	2	2	1	1	0	0	0	3
North Anna Unit 2	33992001	1/29/92	0	2	2	2	1	1	0	0	0	3
North Anna Unit 2	33992007	8/6/92	0	2	2	2	1	1	0	0	0	3
North Anna Unit 2	33993002	4/16/93	0	2	2	2	1	1	0	0	0	3
North Anna Unit 2	33993003	4/24/93	0	2	2	2	1	1	0	0	0	3
North Anna Unit 2	33994003	1/22/94	0	2	2	2	1	1	0	0	0	3
North Anna Unit 2	33995004	11/11/95	0	2	2	2	1	1	0	0	0	3
Oconee Unit 1	26988009	7/5/88	1	2	0	2	1	0	0	0	2	0
Oconee Unit 1	26989001	1/2/89	1	2	0	2	1	0	0	0	2	0
Oconee Unit 1	26989002	1/3/89	1	2	0	2	1	0	0	0	2	0
Oconee Unit 1	26991011	10/2/91	1	2	0	2	1	0	0	0	2	0
Oconee Unit 1	26992004	5/8/92	1	2	0	0	0	0	0	0	2	0
Oconee Unit 1	26992015	10/3/92	1	2	0	0	0	0	0	0	2	0
Oconee Unit 1	26993008	8/23/93	1	2	0	0	0	0	0	0	2	0
Oconee Unit 1	26993010	11/3/93	1	2	0	0	0	0	0	0	2	0
Oconee Unit 1	26994002	2/26/94	1	2	0	0	0	0	0	0	2	0
Oconee Unit 1	26994002	2/26/94	0	0	0	2	1	0	0	0	0	0

Table B-3. (continued)

Plant Name	LER Number	Event Date	Segment Demanded: Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Oconee Unit 2	27087004	4/20/87	1	2	0	2	1	0	0	0	2	0
Oconee Unit 2	27089004	4/3/89	1	2	0	2	1	0	0	0	2	0
Oconee Unit 2	27090001	9/13/90	1	2	0	0	0	0	0	0	2	0
Oconee Unit 2	27092004	10/19/92	0	0	0	2	1	0	0	0	2	0
Oconee Unit 2	27092004	10/19/92	1	2	0	0	0	0	0	0	0	0
Oconee Unit 2	27093001	4/29/93	1	2	0	0	0	0	0	0	2	0
Oconee Unit 2	27093001	4/29/93	0	0	0	2	1	0	0	0	2	0
Oconee Unit 2	27094002	4/6/94	0	0	0	2	1	0	0	0	2	0
Oconee Unit 2	27094002	4/6/94	1	2	0	0	0	0	0	0	2	0
Oconee Unit 2	27094002	4/6/94	1	2	0	0	0	0	0	0	2	0
Oconee Unit 2	27094002	4/6/94	1	2	0	0	0	0	0	0	0	0
Oconee Unit 2	27094002	4/6/94	0	0	0	2	1	0	0	0	0	0
Oconee Unit 2	27094005	12/8/94	1	2	0	2	1	0	0	0	2	0
Oconee Unit 3	28791007	7/3/91	0	0	0	2	1	0	0	0	0	0
Oconee Unit 3	28791007	7/3/91	1	2	0	0	0	0	0	0	2	0
Oconee Unit 3	28792001	1/14/92	0	0	0	2	1	0	0	0	0	0
Oconee Unit 3	28792001	1/14/92	1	2	0	0	0	0	0	0	2	0
Oconee Unit 3	28792001	1/14/92	1	2	0	2	1	0	0	0	0	0
Oconee Unit 3	28792003	6/24/92	1	2	0	0	0	0	0	0	2	0
Oconee Unit 3	28792003	6/24/92	0	0	0	2	1	0	0	0	0	0
Oconee Unit 3	28793001	1/26/93	0	0	0	0	2	0	0	0	0	0
Oconee Unit 3	28793001	1/26/93	1	2	0	0	0	0	0	0	2	0
Oconee Unit 3	28794002	8/10/94	1	2	0	2	1	0	0	0	2	0
Palisades	25587009	3/25/87	0	1	0	0	0	0	0	0	2	0
Palisades	25587024	7/14/87	0	1	0	0	1	0	0	0	2	0
Palisades	25587027	8/23/87	0	1	0	0	0	0	0	0	2	0
Palisades	25589020	8/4/89	0	1	0	0	0	0	0	0	2	0
Palisades	25590001	1/9/90	0	1	0	0	0	0	0	0	2	0
Palisades	25590002	2/28/90	0	1	0	0	0	0	0	0	2	0
Palisades	25591012	7/3/91	0	1	0	0	0	0	0	0	2	0
Palisades	25592034	7/1/92	0	1	0	0	0	0	0	0	2	0
Palisades	25592035	7/24/92	0	1	0	0	0	0	0	0	2	0
Palisades	25592037	8/14/92	0	1	0	0	0	0	0	0	2	0
Palisades	25592038	8/25/92	0	1	0	0	0	0	0	0	2	0
Palisades	25592039	10/30/92	0	1	0	0	0	0	0	0	2	0
Palisades	25595010	8/15/95	0	1	0	0	0	0	0	0	2	0

Table B-3. (continued).

Plant Name	LER Number	Event Date	Segment Demanded: Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Palo Verde Unit 1	52887003	1/10/87	0	1	2	0	0	0	0	0	0	2
Palo Verde Unit 1	52888024	8/27/88	0	1	2	0	0	0	0	0	0	2
Palo Verde Unit 1	52890008	6/20/90	0	1	2	0	0	0	0	0	0	2
Palo Verde Unit 1	52891009	9/14/91	0	1	2	0	0	0	0	0	0	2
Palo Verde Unit 1	52891010	10/27/91	0	1	2	0	0	0	0	0	0	2
Palo Verde Unit 1	52892007	5/6/92	0	1	2	0	0	0	0	0	0	2
Palo Verde Unit 1	52895008	5/30/95	0	1	2	0	0	0	0	0	0	2
Palo Verde Unit 2	52987008	7/22/87	0	1	2	0	0	0	0	0	0	2
Palo Verde Unit 2	52987010	6/4/87	0	1	2	2	1	0	0	0	0	2
Palo Verde Unit 2	52988006	7/26/88	0	1	2	0	0	0	0	0	0	2
Palo Verde Unit 2	52988014	11/16/88	0	1	2	0	0	0	0	0	0	2
Palo Verde Unit 2	52989001	1/3/89	0	1	2	0	0	0	0	0	0	2
Palo Verde Unit 2	52989003	2/16/89	0	1	2	2	1	2	0	0	0	2
Palo Verde Unit 2	52992001	1/9/92	0	1	1	0	0	0	0	0	0	1
Palo Verde Unit 2	52992002	3/23/92	0	1	2	0	0	0	0	0	0	2
Palo Verde Unit 2	52992006	11/13/92	0	1	2	0	0	0	0	0	0	2
Palo Verde Unit 2	52993001	3/14/93	0	1	2	0	0	0	0	0	0	2
Palo Verde Unit 2	52993004	11/1/93	0	1	2	2	1	2	0	0	0	2
Palo Verde Unit 2	52995005	7/17/95	0	1	2	2	1	2	0	0	0	2
Palo Verde Unit 3	52891010	10/27/91	0	1	2	0	0	0	0	0	0	2
Palo Verde Unit 3	52992002	3/23/92	0	1	2	0	0	0	0	0	0	2
Palo Verde Unit 3	53089001	3/3/89	0	1	2	2	1	2	0	0	0	2
Palo Verde Unit 3	53091003	6/19/91	0	1	2	0	0	0	0	0	0	2
Palo Verde Unit 3	53091006	8/24/91	0	1	2	0	0	0	0	0	0	2
Palo Verde Unit 3	53091010	11/15/91	0	1	2	0	0	0	0	0	0	2
Palo Verde Unit 3	53093001	2/4/93	0	1	2	2	1	2	0	0	0	2
Palo Verde Unit 3	53094005	8/19/94	0	1	2	0	0	0	0	0	0	2
Palo Verde Unit 3	53094007	8/30/94	0	1	2	0	0	0	0	0	0	2
Point Beach Unit 1	26689006	5/5/89	0	2	2	0	0	0	0	0	0	2
Point Beach Unit 1	26691008	6/29/91	0	2	2	0	0	0	0	0	0	2
Point Beach Unit 1	26692008	10/5/92	0	2	2	0	0	0	0	0	0	2
Point Beach Unit 1	26695006	7/14/95	0	2	2	0	0	0	0	0	0	2

Table B-3. (continued)

Plant Name	LER Number	Event Date	Segment Demanded: Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Point Beach Unit 2	30187002	8/16/87	0	2	2	2	1	2	0	0	0	2
Point Beach Unit 2	30188001	4/7/88	0	2	2	0	0	0	0	0	0	2
Point Beach Unit 2	30188001	4/7/88	0	2	2	0	0	0	0	0	0	2
Point Beach Unit 2	30189002	3/29/89	0	2	2	2	1	2	0	0	0	2
Point Beach Unit 2	30189004	8/20/89	0	2	0	0	0	0	0	0	0	2
Point Beach Unit 2	30189004	8/20/89	0	2	2	2	1	2	0	0	0	2
Point Beach Unit 2	30191006	12/17/91	0	2	2	0	0	0	0	0	0	2
Point Beach Unit 2	30193002	3/28/93	0	2	2	0	0	0	0	0	0	2
Prairie Island Unit 1	28289010	7/21/89	0	1	2	2	1	2	0	0	2	0
Prairie Island Unit 1	28290017	5/22/89	0	1	2	2	1	2	0	0	2	0
Prairie Island Unit 1	28293005	2/18/93	0	1	2	2	1	2	0	0	2	0
Prairie Island Unit 2	30689002	5/26/89	0	1	2	2	1	2	0	0	2	0
Prairie Island Unit 2	30689004	12/21/89	0	1	2	2	1	2	0	0	2	0
Prairie Island Unit 2	30690001	3/8/90	0	1	2	2	1	2	0	0	2	0
Prairie Island Unit 2	30690003	3/16/90	0	1	2	2	1	2	0	0	2	0
Prairie Island Unit 2	30690012	12/29/90	0	1	2	2	1	2	0	0	2	0
Prairie Island Unit 2	30692001	2/19/92	0	1	2	0	0	0	0	0	2	0
Prairie Island Unit 2	30694002	7/21/94	0	1	2	2	1	2	0	0	2	0
Robinson 2	26187018	6/15/87	0	2	3	0	0	0	0	0	0	0
Robinson 2	26187020	7/10/87	0	2	3	0	0	0	0	0	0	0
Robinson 2	26187020	7/16/87	0	2	3	0	0	0	0	0	0	0
Robinson 2	26188001	1/19/88	0	2	3	3	1	0	0	0	0	0
Robinson 2	26188010	5/2/88	0	2	3	3	1	0	0	0	0	0
Robinson 2	26189005	3/22/89	0	2	3	0	0	0	0	0	0	0
Robinson 2	26189006	3/30/89	0	2	3	0	0	0	0	0	0	0
Robinson 2	26190002	1/17/90	0	2	3	0	0	0	0	0	0	0
Robinson 2	26190007	5/17/90	0	2	3	0	0	0	0	0	0	0
Robinson 2	26191011	8/30/91	0	2	3	0	0	0	0	0	0	0
Robinson 2	26192017	8/22/92	0	2	3	3	1	0	0	0	0	0
Robinson 2	26194006	4/3/94	0	2	3	0	0	0	0	0	0	0
Robinson 2	26194016	8/2/94	0	2	3	0	0	0	0	0	0	0
Robinson 2	26195004	6/30/95	0	2	3	0	0	0	0	0	0	0

Table B-3. (continued).

			Segment Demanded									
Plant Name	LER Number	Event Date	Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
St. Lucie Unit 1	33587002	2/7/87	0	2	2	0	0	0	0	0	0	2
St. Lucie Unit 1	33587011	5/21/87	0	2	2	2	1	2	0	0	0	2
St. Lucie Unit 1	33587013	6/14/87	0	2	2	2	1	2	0	0	0	2
St. Lucie Unit 1	33587016	10/29/87	0	2	2	0	0	0	0	0	0	2
St. Lucie Unit 1	33587017	12/21/87	0	2	2	2	1	2	0	0	0	2
St. Lucie Unit 1	33588003	3/28/88	0	2	2	2	1	2	0	0	0	2
St. Lucie Unit 1	33588004	6/30/88	0	2	2	2	1	2	0	0	0	2
St. Lucie Unit 1	33588008	9/20/88	0	2	2	2	1	2	0	0	0	2
St. Lucie Unit 1	33589003	7/17/89	0	2	2	0	0	0	0	0	0	2
St. Lucie Unit 1	33589005	9/13/89	0	2	2	2	1	2	0	0	0	2
St. Lucie Unit 1	33590007	5/24/90	0	2	2	2	1	2	0	0	0	2
St. Lucie Unit 1	33591003	5/6/91	0	1	1	2	1	1	0	0	0	1
St. Lucie Unit 1	33591005	7/1/91	0	1	1	2	1	1	0	0	0	1
St. Lucie Unit 1	33591006	9/18/91	0	1	1	2	1	1	0	0	0	1
St. Lucie Unit 1	33592006	9/24/92	0	2	2	0	0	0	0	0	0	2
St. Lucie Unit 1	33594001	1/9/94	0	2	2	2	1	2	0	0	0	2
St. Lucie Unit 1	33594003	3/28/94	0	2	2	2	1	2	0	0	0	2
St. Lucie Unit 1	33594004	4/3/94	0	2	2	2	1	2	0	0	0	2
St. Lucie Unit 1	33595010	11/16/95	0	2	2	2	1	2	0	0	0	2
St. Lucie Unit 2	38987001	3/3/87	0	2	2	2	1	2	0	0	0	2
St. Lucie Unit 2	38987002	3/5/87	0	1	1	2	1	1	0	0	0	1
St. Lucie Unit 2	38987003	4/9/87	0	2	2	2	1	2	0	0	0	2
St. Lucie Unit 2	38987004	4/22/87	0	2	2	2	1	2	0	0	0	2
St. Lucie Unit 2	38987007	11/25/87	0	2	2	0	0	0	0	0	0	2
St. Lucie Unit 2	38989007	9/23/89	0	2	2	2	1	2	0	0	0	2
St. Lucie Unit 2	38990001	1/14/90	0	2	2	2	1	2	0	0	0	2
St. Lucie Unit 2	38992004	7/8/92	0	2	2	2	1	2	0	0	0	2
St. Lucie Unit 2	38992005	7/10/92	0	2	2	2	1	2	0	0	0	2
St. Lucie Unit 2	38992006	8/10/92	0	2	2	2	1	2	0	0	0	2
St. Lucie Unit 2	38995002	2/21/95	0	2	2	2	1	2	0	0	0	2
Salem Unit 1	27288009	3/30/88	0	2	4	0	0	0	0	0	0	4
Salem Unit 1	27289007	2/6/89	0	2	4	0	0	0	0	0	0	4
Salem Unit 1	27289027	6/19/89	0	2	4	0	0	0	0	0	0	4
Salem Unit 1	27290012	4/9/90	0	2	4	0	0	0	0	0	0	4
Salem Unit 1	27290030	9/10/90	0	2	4	2	1	4	0	0	0	4
Salem Unit 1	27291024	6/16/91	0	2	4	2	1	4	0	0	0	4
Salem Unit 1	27293013	7/19/93	0	2	4	2	1	4	0	0	0	4

Table B-3. (continued)

Plant Name	LER Number	Event Date	Segment Demanded: Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Salem Unit 1	27294003	1/27/94	0	2	4	0	0	0	0	0	0	4
Salem Unit 1	27294005	2/10/94	0	2	4	0	0	0	0	0	0	4
Salem Unit 1	27294006	4/7/94	0	2	4	0	0	0	0	0	0	4
Salem Unit 1	27294009	6/10/94	0	2	4	0	0	0	0	0	0	4
Salem Unit 1	27294011	8/15/91	0	2	4	2	1	4	0	0	0	4
Salem Unit 2	31188014	6/22/88	0	2	4	0	0	0	0	0	0	4
Salem Unit 2	31188017	8/31/88	0	2	4	0	0	0	0	0	0	4
Salem Unit 2	31188024	11/28/88	0	2	4	2	1	4	0	0	0	4
Salem Unit 2	31189003	2/5/89	0	2	4	0	0	0	0	0	0	4
Salem Unit 2	31189005	3/12/89	0	2	4	0	0	0	0	0	0	4
Salem Unit 2	31189008	4/11/89	0	2	4	0	0	0	0	0	0	4
Salem Unit 2	31190029	6/28/90	0	2	4	2	1	4	0	0	0	4
Salem Unit 2	31191017	11/9/91	0	2	4	0	0	0	0	0	0	4
Salem Unit 2	31192009	5/14/92	0	2	4	0	0	0	0	0	0	4
Salem Unit 2	31192014	9/3/92	0	2	4	0	0	0	0	0	0	4
Salem Unit 2	31193002	1/28/93	0	2	4	2	1	4	0	0	0	4
Salem Unit 2	31193005	3/16/93	0	2	4	2	1	4	0	0	0	4
Salem Unit 2	31193009	6/22/93	0	2	4	0	0	0	0	0	0	4
Salem Unit 2	31194003	1/27/94	0	2	4	0	0	0	0	0	0	4
Salem Unit 2	31194008	6/29/94	0	2	4	2	1	4	0	0	0	4
Salem Unit 2	31195004	6/7/95	0	2	4	2	1	4	0	0	0	4
San Onofre Unit 2	36187001	2/5/87	0	2	2	2	1	2	0	0	2	0
San Onofre Unit 2	36187004	3/28/87	0	1	1	2	1	2	0	0	2	0
San Onofre Unit 2	36187031	12/17/87	0	2	2	2	1	2	0	0	2	0
San Onofre Unit 2	36190016	12/6/90	0	2	2	2	1	2	0	0	2	0
San Onofre Unit 2	36191007	4/10/91	0	2	2	2	1	2	0	0	2	0
San Onofre Unit 2	36192008	4/24/92	0	2	2	2	1	2	0	0	2	0
San Onofre Unit 2	36192012	7/31/92	0	2	2	2	1	2	0	0	2	0
San Onofre Unit 3	36287011	6/21/87	0	2	2	2	1	2	0	0	2	0
San Onofre Unit 3	36287017	10/11/87	0	1	1	2	1	2	0	0	2	0
San Onofre Unit 3	36289001	1/6/89	0	2	2	2	1	2	0	0	2	0
San Onofre Unit 3	36289006	4/7/89	0	2	2	2	1	2	0	0	2	0
San Onofre Unit 3	36290002	2/23/90	0	2	2	2	1	2	0	0	2	0
San Onofre Unit 3	36291001	3/15/91	0	2	2	2	1	2	0	0	2	0
San Onofre Unit 3	36292003	5/15/92	0	2	2	2	1	2	0	0	2	0

Table B-3. (continued).

Plant Name	LER Number	Event Date	Segment Demanded									
			Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
San Onofre Unit 3	36292004	7/20/92	0	2	2	2	1	2	0	0	0	0
San Onofre Unit 3	36293004	7/5/93	0	2	2	2	1	2	0	0	0	0
Seabrook	44387009	3/10/87	0	1	0	0	0	0	0	0	4	0
Seabrook	44390015	6/20/90	0	1	0	2	1	0	0	0	4	0
Seabrook	44390018	7/5/90	0	1	0	2	1	0	0	0	4	0
Seabrook	44390022	8/22/90	0	1	0	2	1	0	0	0	4	0
Seabrook	44390025	11/9/90	0	1	0	2	1	0	0	0	4	0
Seabrook	44391001	2/12/91	0	1	0	2	1	0	0	0	4	0
Seabrook	44391002	3/30/91	0	1	0	2	1	0	0	0	4	0
Seabrook	44391008	6/27/91	0	1	0	2	1	0	0	0	4	0
Seabrook	44391009	7/4/91	0	1	0	2	1	0	0	0	4	0
Seabrook	44392017	9/7/92	0	1	0	2	1	0	0	0	4	0
Seabrook	44392024	11/27/92	0	1	0	2	1	0	0	0	4	0
Seabrook	44392025	12/13/92	0	1	0	2	1	0	0	0	4	0
Seabrook	44393003	1/14/93	0	1	0	2	1	0	0	0	4	0
Seabrook	44393009	5/20/93	0	2	0	4	2	0	0	0	8	0
Seabrook	44393012	7/27/93	0	1	0	2	1	0	0	0	4	0
Seabrook	44393018	9/22/93	0	1	0	2	1	0	0	0	4	0
Seabrook	44394001	1/25/94	0	1	0	2	1	0	0	0	4	0
Sequoyah Unit 1	32788045	11/18/88	0	0	0	2	1	4	0	0	0	0
Sequoyah Unit 1	32788045	11/18/88	0	2	4	0	0	0	0	0	4	0
Sequoyah Unit 1	32788047	12/25/88	0	0	0	2	1	0	0	0	4	0
Sequoyah Unit 1	32788047	12/25/88	0	2	4	0	0	0	0	0	0	0
Sequoyah Unit 1	32789005	2/10/89	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 1	32789035	12/10/89	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 1	32790012	6/2/90	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 1	32790021	9/14/90	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 1	32790022	9/19/90	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 1	32790030	11/15/90	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 1	32792010	4/28/92	0	2	4	0	0	0	0	0	4	0
Sequoyah Unit 1	32792012	5/16/92	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 1	32792018	10/26/92	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 1	32792027	12/31/92	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 1	32794011	7/15/94	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 1	32794014	11/29/94	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 1	32795008	6/23/95	0	2	4	2	1	4	0	0	4	0

Table B-3. (continued)

Plant Name	LER Number	Event Date	Segment Demanded: Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Sequoyah Unit 2	32792027	12/31/92	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 2	32888014	3/20/88	0	0	0	2	1	4	0	0	0	0
Sequoyah Unit 2	32888023	5/19/88	0	2	2	2	1	4	0	0	4	0
Sequoyah Unit 2	32888024	5/23/88	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 2	32888027	6/6/88	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 2	32888028	6/9/88	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 2	32888028	6/8/88	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 2	32889005	4/19/89	0	2	4	0	0	0	0	0	4	0
Sequoyah Unit 2	32889008	7/10/89	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 2	32890008	4/10/90	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 2	32890017	11/23/90	0	2	0	0	0	0	0	0	4	0
Sequoyah Unit 2	32891001	1/3/91	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 2	32891006	11/7/91	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 2	32892001	2/10/92	0	0	0	2	1	4	0	0	0	0
Sequoyah Unit 2	32892001	2/10/92	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 2	32892008	6/27/92	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 2	32892011	8/21/92	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 2	32892012	9/4/92	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 2	32892015	12/8/92	0	2	4	0	0	0	0	0	4	0
Sequoyah Unit 2	32895001	1/5/95	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 2	32895002	4/28/95	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 2	32895003	5/31/95	0	2	4	2	1	4	0	0	4	0
Sequoyah Unit 2	32895007	12/21/95	0	2	4	2	1	4	0	0	4	0
South Texas Unit 1	49888022	2/28/88	0	3	3	1	1	1	0	0	0	0
South Texas Unit 1	49888045	7/19/88	0	3	3	1	1	1	0	0	0	0
South Texas Unit 1	49888048	8/16/88	0	3	3	1	1	1	0	0	0	0
South Texas Unit 1	49888049	8/26/88	0	3	3	1	1	1	0	0	0	0
South Texas Unit 1	49889001	1/3/89	0	3	3	1	1	1	0	0	0	0
South Texas Unit 1	49889015	7/4/89	0	3	3	1	1	1	0	0	0	0
South Texas Unit 1	49890005	3/29/90	0	3	3	1	1	1	0	0	0	0
South Texas Unit 1	49890006	7/30/90	0	3	3	1	1	1	0	0	0	0
South Texas Unit 1	49890014	6/20/90	0	3	3	1	1	1	0	0	0	0
South Texas Unit 1	49890015	6/28/90	0	3	3	1	1	1	0	0	0	0
South Texas Unit 1	49890016	7/2/90	0	3	3	1	1	1	0	0	0	0
South Texas Unit 1	49890020	7/16/90	0	3	3	1	1	1	0	0	0	0
South Texas Unit 1	49890023	9/29/90	0	3	3	1	1	1	0	0	0	0
South Texas Unit 1	49890025	11/24/90	0	3	3	1	1	1	0	0	0	0

Table B-3. (continued).

Plant Name	LER Number	Event Date	Segment Demanded: Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
South Texas Unit 1	49891012	4/12/91	0	3	3	1	1	1	0	0	0	0
South Texas Unit 1	49891021	10/10/91	0	3	3	1	1	1	0	0	0	0
South Texas Unit 1	49891022	10/14/91	0	3	3	1	1	1	0	0	0	0
South Texas Unit 1	49892003	3/14/92	0	3	3	1	1	1	0	0	0	0
South Texas Unit 1	49894009	2/28/94	0	3	3	1	1	1	0	0	0	0
South Texas Unit 1	49894015	9/20/94	0	3	3	1	1	1	0	0	0	0
South Texas Unit 1	49895001	1/24/95	0	3	3	1	1	1	0	0	0	0
South Texas Unit 1	49895009	8/29/95	0	3	3	1	1	1	0	0	0	0
South Texas Unit 1	49895013	12/18/95	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49989009	4/5/89	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49989011	4/10/89	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49989013	4/15/89	0	2	2	1	1	1	0	0	0	0
South Texas Unit 2	49989013	4/15/89	0	1	1	1	1	1	0	0	0	0
South Texas Unit 2	49989016	6/2/89	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49989017	7/13/89	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49989019	8/23/89	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49989020	8/29/89	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49989021	9/5/89	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49989022	9/19/89	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49989023	9/22/89	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49989026	10/13/89	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49990002	2/2/90	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49990004	3/26/90	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49990005	4/14/90	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49990012	7/13/90	0	3	3	0	0	0	0	0	0	0
South Texas Unit 2	49990013	9/17/90	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49991001	1/9/91	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49991003	3/14/91	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49991003	3/14/91	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49991004	3/30/91	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49991010	12/24/91	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49992001	1/22/92	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49992003	2/24/92	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49992010	12/27/92	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49993001	1/23/93	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49993004	2/3/93	0	3	3	1	1	0	0	0	0	0
South Texas Unit 2	49994007	6/25/94	0	3	3	1	1	1	0	0	0	0

Table B-3. (continued)

Plant Name	LER Number	Event Date	Segment Demanded: Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
South Texas Unit 2	49995003	3/28/95	0	3	3	1	1	1	0	0	0	0
South Texas Unit 2	49995008	11/15/95	0	3	3	1	1	1	0	0	0	0
Summer	39587015	6/16/87	0	2	3	2	1	3	0	0	0	3
Summer	39587021	9/2/87	0	2	3	0	0	0	0	0	0	3
Summer	39587027	10/29/87	0	2	3	2	1	3	0	0	0	3
Summer	39588002	2/16/88	0	2	3	2	1	3	0	0	0	3
Summer	39588006	5/12/88	0	2	3	2	1	3	0	0	0	3
Summer	39588007	6/1/88	0	2	3	2	1	3	0	0	0	3
Summer	39588009	7/26/88	0	2	3	0	0	0	0	0	0	3
Summer	39588009	7/26/88	0	0	0	2	1	3	0	0	0	0
Summer	39589011	5/28/89	0	2	3	0	0	0	0	0	0	3
Summer	39589012	7/11/89	0	2	3	0	0	0	0	0	0	3
Summer	39589015	8/25/89	0	2	3	0	0	0	0	0	0	3
Summer	39589020	12/2/89	0	2	3	2	1	3	0	0	0	3
Summer	39593001	1/12/93	0	2	3	0	0	0	0	0	0	3
Surry Unit 1	28087024	9/20/87	0	2	0	0	0	0	0	0	6	3
Surry Unit 1	28088003	2/16/88	0	2	0	0	0	0	0	0	6	3
Surry Unit 1	28088029	8/15/88	0	2	0	0	0	0	0	0	6	3
Surry Unit 1	28090004	5/22/90	0	2	0	0	0	0	0	0	6	3
Surry Unit 1	28090006	7/1/90	0	2	0	0	0	0	0	0	6	3
Surry Unit 1	28092001	1/2/92	0	2	0	2	1	0	0	0	6	3
Surry Unit 1	28092007	5/7/92	0	2	0	0	0	0	0	0	6	3
Surry Unit 1	28093001	1/8/93	0	2	0	2	1	0	0	0	6	3
Surry Unit 1	28093001	1/8/93	0	2	0	0	0	0	0	0	6	3
Surry Unit 1	28093002	2/9/93	0	2	0	2	1	0	0	0	6	3
Surry Unit 1	28094006	5/11/94	0	2	0	2	1	0	0	0	6	3
Surry Unit 1	28095001	1/8/95	0	2	0	2	1	0	0	0	6	3
Surry Unit 1	28095003	4/12/95	0	2	0	2	1	0	0	0	6	3
Surry Unit 2	28090004	5/22/90	0	2	0	0	0	0	0	0	6	3
Surry Unit 2	28188004	3/27/88	0	2	0	0	0	0	0	0	6	3
Surry Unit 2	28188010	5/16/88	0	2	0	0	0	0	0	0	6	3
Surry Unit 2	28189010	9/19/89	0	2	0	2	1	0	0	0	6	3
Surry Unit 2	28190003	5/31/90	0	2	0	0	0	0	0	0	6	3
Surry Unit 2	28190004	8/27/90	0	2	0	0	0	0	0	0	6	3
Surry Unit 2	28191011	12/17/91	0	1	0	0	0	0	0	0	3	2

Table B-3. (continued).

			Segment Demanded									
Plant Name	LER Number	Event Date	Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Surry Unit 2	28191011	12/17/91	0	1	0	0	0	0	0	0	3	1
Surry Unit 2	28193002	6/23/93	0	2	0	0	0	0	0	0	6	3
Surry Unit 2	28193003	8/3/93	0	2	0	2	1	0	0	0	6	3
Surry Unit 2	28193004	8/23/93	0	2	0	0	0	0	0	0	6	3
Surry Unit 2	28193005	8/27/93	0	2	0	0	0	0	0	0	6	3
Surry Unit 2	28193006	11/15/93	0	2	0	0	0	0	0	0	6	3
Surry Unit 2	28195004	5/11/95	0	2	0	2	1	0	0	0	6	3
Surry Unit 2	28195005	5/21/95	0	2	0	2	1	0	0	0	6	3
Surry Unit 2	28195006	6/14/95	0	2	0	0	0	0	0	0	6	3
Surry Unit 2	28195007	11/7/95	0	2	0	0	0	0	0	0	6	3
Three Mile Isl. Unit 1	28988004	8/13/88	2	2	0	2	1	0	0	0	2	0
Three Mile Isl. Unit 1	28991003	9/27/91	2	2	0	2	1	0	0	0	2	0
Three Mile Isl. Unit 1	28993003	3/12/93	2	2	0	2	1	0	0	0	2	0
Turkey Point Unit 3	25087001	1/4/87	2	0	0	3	3	0	0	0	0	6
Turkey Point Unit 3	25088004	3/18/88	2	0	0	3	3	0	0	0	0	6
Turkey Point Unit 3	25089005	2/15/89	2	0	0	3	3	0	0	0	0	6
Turkey Point Unit 3	25090011	6/9/90	2	0	0	3	3	0	0	0	0	6
Turkey Point Unit 3	25094006	12/6/94	2	0	0	3	3	0	0	0	0	6
Turkey Point Unit 3	25095007	10/17/95	2	0	0	3	3	0	0	0	0	6
Turkey Point Unit 4	25089020	12/23/89	2	0	0	3	3	0	0	0	0	6
Turkey Point Unit 4	25187001	1/6/87	2	0	0	0	3	0	0	0	0	6
Turkey Point Unit 4	25188009	8/16/88	2	0	0	3	3	0	0	0	0	6
Turkey Point Unit 4	25188010	8/19/88	2	0	0	3	3	0	0	0	0	6
Turkey Point Unit 4	25189011	9/15/89	2	0	0	3	3	0	0	0	0	6
Turkey Point Unit 4	25190003	4/9/90	2	0	0	3	3	0	0	0	0	6
Turkey Point Unit 4	25190008	8/12/90	2	0	0	3	3	0	0	0	0	6
Turkey Point Unit 4	25191006	10/29/91	2	0	0	3	3	0	0	0	0	6
Turkey Point Unit 4	25192007	9/29/92	2	0	0	0	3	0	0	0	0	6
Turkey Point Unit 4	25193003	8/16/93	2	0	0	3	3	0	0	0	0	6
Turkey Point Unit 4	25194004	9/23/94	2	0	0	3	3	0	0	0	0	6
Turkey Point Unit 4	25194006	11/30/94	2	0	0	3	3	0	0	0	0	6
Vogtle Unit 1	42487009	3/25/87	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42487009	3/23/87	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42487009	3/26/87	0	2	4	2	1	4	0	0	0	4

Table B-3. (continued)

Plant Name	LER Number	Event Date	Segment Demanded: Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Vogtle Unit 1	42487009	3/23/87	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42487009	3/20/87	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42487009	3/20/87	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42487010	3/24/87	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42487010	3/21/87	0	0	0	2	1	4	0	0	0	0
Vogtle Unit 1	42487011	3/26/87	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42487012	4/5/87	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42487013	4/10/87	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42487014	4/11/87	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42487015	4/13/87	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42487018	5/4/87	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42487018	4/29/87	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42487025	5/9/87	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42487026	5/10/87	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42487027	5/13/87	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42487029	5/24/87	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42487030	6/3/87	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42487033	6/7/87	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42487034	6/7/87	0	1	2	0	0	0	0	0	0	2
Vogtle Unit 1	42487035	6/14/87	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42487041	6/23/87	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42487047	7/8/87	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42487047	7/22/87	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42487050	7/28/87	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42487063	11/5/87	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42487066	11/11/87	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42488001	1/17/88	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42488006	2/15/88	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42488008	4/7/88	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42488013	4/24/88	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42488022	7/14/88	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42488024	7/30/88	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42488025	7/31/88	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42488043	12/15/88	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42488044	12/17/88	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42488044	12/17/88	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42489005	2/10/89	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42489012	5/9/89	0	2	4	2	1	4	0	0	0	4

Table B-3. (continued).

Plant Name	LER Number	Event Date	Segment Demanded: Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Vogtle Unit 1	42489016	7/8/89	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42489016	8/3/89	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42489018	10/2/89	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42490001	1/24/90	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42490011	4/25/90	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42490016	7/23/90	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42490023	12/18/90	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42492008	9/14/92	0	0	0	2	1	4	0	0	0	4
Vogtle Unit 1	42492008	9/14/92	0	2	4	0	0	0	0	0	0	0
Vogtle Unit 1	42493008	5/3/93	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42493009	7/28/93	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 1	42494002	3/11/94	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 1	42495002	7/23/95	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 2	42495002	7/23/95	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 2	42589018	4/22/89	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 2	42589018	4/22/89	0	0	0	2	1	4	0	0	0	0
Vogtle Unit 2	42589019	5/2/89	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 2	42589020	5/12/89	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 2	42589021	5/22/89	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 2	42589023	7/20/89	0	1	2	0	0	0	0	0	0	0
Vogtle Unit 2	42589023	7/20/89	0	0	0	2	1	4	0	0	0	4
Vogtle Unit 2	42589024	7/26/89	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 2	42589027	10/11/89	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 2	42589029	11/5/89	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 2	42589031	12/2/89	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 2	42590002	3/20/90	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 2	42590007	5/6/90	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 2	42590008	6/28/90	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 2	42590009	6/30/90	0	2	4	0	0	0	0	0	0	0
Vogtle Unit 2	42591005	2/18/91	0	0	0	2	1	4	0	0	0	4
Vogtle Unit 2	42591005	2/18/91	0	2	4	0	0	0	0	0	0	0
Vogtle Unit 2	42591006	2/23/91	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 2	42591007	5/7/91	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 2	42592002	3/9/92	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 2	42592010	5/14/92	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 2	42593004	6/28/93	0	2	4	2	1	4	0	0	0	4
Vogtle Unit 2	42593006	9/8/93	0	2	4	0	0	0	0	0	0	0

Table B-3. (continued)

Plant Name	LER Number	Event Date	Segment Demanded: Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Vogtle Unit 2	42593006	9/8/93	0	0	0	2	1	4	0	0	0	4
Vogtle Unit 2	42594001	1/7/94	0	2	4	0	0	0	0	0	0	4
Vogtle Unit 2	42594002	1/19/94	0	2	4	0	0	0	0	0	0	4
Waterford 3	38287008	3/15/87	0	2	0	2	1	0	0	0	0	0
Waterford 3	38287012	4/13/87	0	2	0	2	1	0	0	0	0	0
Waterford 3	38287016	5/25/87	0	2	0	2	1	0	0	0	4	2
Waterford 3	38287020	7/31/87	0	2	0	2	1	0	0	0	0	0
Waterford 3	38287028	12/11/87	0	2	0	2	1	0	0	0	4	2
Waterford 3	38288002	1/26/88	0	2	0	2	1	0	0	0	0	0
Waterford 3	38288016	6/14/88	0	2	0	2	1	0	0	0	0	0
Waterford 3	38288033	12/8/88	0	2	0	2	1	0	0	0	0	0
Waterford 3	38289013	7/15/89	0	2	0	2	1	0	0	0	4	2
Waterford 3	38289024	12/23/89	0	2	0	2	1	0	0	0	2	1
Waterford 3	38290002	3/22/90	0	2	0	2	1	0	0	0	0	0
Waterford 3	38290003	3/29/90	0	2	0	2	1	0	0	0	4	2
Waterford 3	38290012	8/25/90	0	2	0	2	1	0	0	0	4	2
Waterford 3	38291013	6/24/91	0	2	0	2	1	0	0	0	4	2
Waterford 3	38291019	8/25/91	0	0	0	2	1	0	0	0	0	0
Waterford 3	38291019	8/25/91	0	2	0	0	0	0	0	0	4	2
Waterford 3	38291022	11/17/91	0	2	0	0	0	0	0	0	4	2
Waterford 3	38291022	11/17/91	0	0	0	2	1	0	0	0	4	2
Waterford 3	38293001	3/4/93	0	2	0	2	1	0	0	0	4	2
Waterford 3	38293002	6/15/93	0	2	0	2	1	0	0	0	4	2
Waterford 3	38295002	6/10/95	0	2	0	2	1	0	0	0	4	2
Wolf Creek	48287002	1/8/87	0	2	4	0	0	0	0	0	0	4
Wolf Creek	48287004	1/20/87	0	2	4	0	0	0	0	0	0	4
Wolf Creek	48287005	1/17/87	0	2	4	0	0	0	0	0	0	4
Wolf Creek	48287005	1/21/87	0	2	4	0	0	0	0	0	0	4
Wolf Creek	48287017	4/23/87	0	2	4	0	0	0	0	0	0	4
Wolf Creek	48287017	4/19/87	0	2	4	0	0	0	0	0	0	4
Wolf Creek	48287022	5/28/87	0	2	4	2	1	4	0	0	0	4
Wolf Creek	48287027	6/29/87	0	2	4	2	1	4	0	0	0	4
Wolf Creek	48287030	7/20/87	0	2	4	2	1	4	0	0	0	4
Wolf Creek	48287037	9/10/87	0	2	4	2	1	4	0	0	0	4
Wolf Creek	48287037	9/12/87	0	2	4	0	0	0	0	0	0	4
Wolf Creek	48287037	9/10/87	0	0	0	2	1	4	0	0	0	0

Table B-3. (continued).

Plant Name	LER Number	Event Date	Segment Demanded									
			Suction	MDP	MDP Feed	TDP Steam	TDP	TDP Feed	DDP	DDP Feed	Common Feed	S/G Feed
Wolf Creek	48287037	9/11/87	0	2	4	0	0	0	0	0	0	4
Wolf Creek	48287041	9/27/87	0	2	4	0	0	0	0	0	0	4
Wolf Creek	48287051	12/26/87	0	1	2	0	0	0	0	0	0	2
Wolf Creek	48289002	1/23/89	0	2	4	0	0	0	0	0	0	4
Wolf Creek	48289004	2/2/89	0	2	4	0	0	0	0	0	0	4
Wolf Creek	48289013	7/11/89	0	1	2	0	0	0	0	0	0	2
Wolf Creek	48290001	2/6/90	0	2	4	0	0	0	0	0	0	4
Wolf Creek	48290011	5/14/90	0	2	4	0	0	0	0	0	0	4
Wolf Creek	48290012	5/17/90	0	2	4	0	0	0	0	0	0	4
Wolf Creek	48290013	5/19/90	0	2	4	0	0	0	0	0	0	4
Wolf Creek	48290014	6/13/90	0	1	2	2	1	4	0	0	0	4
Wolf Creek	48290023	10/23/90	0	1	2	0	0	0	0	0	0	4
Wolf Creek	48290023	10/23/90	0	0	0	2	1	4	0	0	0	0
Wolf Creek	48291006	5/12/91	0	1	2	2	1	4	0	0	0	4
Wolf Creek	48292002	2/19/92	0	2	4	0	0	0	0	0	0	4
Wolf Creek	48292016	11/10/92	0	1	2	0	0	0	0	0	0	0
Wolf Creek	48292016	11/10/92	0	1	2	0	0	0	0	0	0	0
Wolf Creek	48292016	11/10/92	0	0	0	2	1	4	0	0	0	4
Wolf Creek	48294002	2/19/94	0	2	4	0	0	0	0	0	0	4
Wolf Creek	48295001	3/8/95	0	2	4	2	1	4	0	0	0	4
Wolf Creek	48295006	11/10/95	0	0	0	2	1	4	0	0	0	4
Zion Unit 1	29587005	2/27/87	0	2	1	0	0	0	0	0	0	1
Zion Unit 1	29588011	5/7/88	0	2	4	0	0	0	0	0	0	4
Zion Unit 1	29589009	6/20/89	0	1	0	0	0	0	0	0	0	0
Zion Unit 1	29590004	1/27/90	0	2	4	0	0	0	0	0	0	4
Zion Unit 1	29591016	11/7/91	0	2	4	0	0	0	0	0	0	4
Zion Unit 1	29594005	4/3/94	0	2	4	2	1	4	0	0	0	4
Zion Unit 1	29594010	7/2/94	0	2	4	0	0	0	0	0	0	4
Zion Unit 2	30488007	10/8/88	0	2	4	0	0	0	0	0	0	4
Zion Unit 2	30490001	1/18/90	0	2	4	0	0	0	0	0	0	4
Zion Unit 2	30490010	9/7/90	0	2	4	0	0	0	0	0	0	4
Zion Unit 2	30490013	11/11/90	0	2	4	0	0	0	0	0	0	4

Appendix C

AFW Unreliability Events, 1987–1995

Appendix C

AFW Unreliability Events, 1987–1995

The events classified as segment failures that occurred as part of an unplanned demand of any segment of the auxiliary feedwater (AFW) system were used for the statistical estimation of unreliability. Table C-1 provides a summary description of the events used to determine system unreliability. The table lists the events alphabetically by segment type. Within each segment type, the events are first sorted by failure mode, i.e., failure to run or failure to start, and then each failure mode is sorted alphabetically by plant name. To simplify the unreliability analysis, all the failures to operate of the various feed control segments were combined into one segment listed as "feed control." The events classified as common cause failures (CCF) are identified as "CCF" in parentheses next to the failure mode. For the failures for which two or more segments failed, the number of failures are also identified in parentheses next to the failure mode.

Three 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 the engineers. The events that were 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 AFW system to complete its mission. As an example, an electric-motor-driven pump segment may have failed to start; however, the turbine-driven and/or redundant electric-motor-driven pump segment may have responded as designed for the mission. Hence, the system was not failed

Failure classification of the events for a risk-based mission was based on the ability of the AFW system to function as designed for at least 24 hours. Inoperability events classified as failures for an operational mission were based on successful operation while the system was needed. Thus, events could be classified as failures for a risk-based mission even if the system functioned successfully for the operational mission. Therefore, these events would be included in the failure count for a risk-based mission, but would not be included in the failure count for an operational mission. An example of such a failure would be a turbine governor oil leak that would allow the turbine to operate while it was needed to restore steam generator level (15 minutes). However, the oil leak would fail the turbine, and hence the pump, in a longer 24 hour risk-based mission. Each LER was reviewed to determine if the segment would have been reasonably capable of performing its safety function for each mission.

For the events associated with the feed control 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 a feed control 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 feed control 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 feed control segment was classified as failed.

Some of the LERs identified feed control valves that failed in the open position, while failure of a valve in the open position could be considered a “fail-safe” position, these malfunctions of the flow control valves were classified as failures of the feed control segment to operate. This classification was based on the need for the feed control 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. As an example, if a feed control valve failed open for a motor-driven pump, the pump would fill the steam generator to the steam lines and subsequently fail the turbine-driven pump. The turbine-driven pump failure would occur through actuation of the high steam generator water level trip that closes the trip-throttle valve. In addition, water would still enter the turbine steam supply piping, and during any subsequent restart of the turbine it would overspeed as a result of the water accumulation. As a result of the impact on the turbine-driven pump, the feed control segment was classified as failed.

A second rational for classifying a failed open feed control valve as a failure of the feed control segment stems from the shutdown of the motor-driven pump by the control room operator prior to reaching a high level condition (Same example as stated in the previous paragraph). If the motor-driven pump is shutdown, the shutdown of the motor-driven pump effectively fails the motor-driven pump segment for the remainder of the operational or risk-based mission. This is because continued heat removal through the atmospheric dump valves would not end once the generator level is initially restored above the autostart setpoint. Steam would continue to be bled from the steam generator lowering the level to the autostart setpoint. The pump would restart with a wide open valve drawing an unusually high starting current (normal starting current is five times running current with a discharge closed) which could damage the motor windings. Given that the pump would have to be restarted many times over a 24 hour period for a risk-mission, damage to the motor windings would be inevitable. In addition, for an operational mission, as the cooldown continues steam generator pressure would lower. As the downstream pressure of the pump lowers, flow rates would increase. This could result in excessive pump flow rates and possibly a pump runout condition if flow is greater than design flow. The excessive flow that could occur from the reduced steam generator pressure would cause motor amps to increase and this high amperage could cause the motor circuit breaker to open or possible damage to the motor windings.

Overall, while a failed open flow control valve could be considered a “fail safe” position, this “fail safe” designation does not take into account long-term operation of the segment for either an operational or risk-mission. In either of these missions, a pump segment would have to be shutdown because of the failed open valve. While is possible to successfully operate the segment with a failed open valve by throttling a pump discharge isolation, this action is considered a recovery action for the segment and not a normal successful operation of the segment.

Table C-1. Events used to estimate unreliability.

Plant Name	LER Number	Segment[a]	Failure Mode	Description
Byron Unit 2	45588005	Diesel-driven pump	FTR	The diesel-driven pump fuel oil tank level indicator failed. The diesel ran for the required operational mission. However, operators were unaware of the loss of level indication in the tank for 2 days. The event was classified as a failure of a 24-hour risk--based mission based on the safety analysis provided by the plant. The safety analysis indicated that the engine would only have run for 5 hours and 20 minutes before the tank would have emptied failing the engine at that time. The failure was not recovered.
Byron Unit 2	45588008	Diesel-driven pump	FTS	A loose ground terminal for the engine speed sensor caused the engine to overspeed. The loose ground terminal caused false, intermittent overspeed signals that resulted in an engine trip. The engine was restarted manually by plant operators. The failure was recovered.
Beaver Valley Unit 2	41287035	Feed control	FTO	A flow control valve for a steam generator failed open and would not respond to control signals as a result of a blown control fuse. A failed open flow control valve results in a steam generator overfill with the resulting pump trip on high level or as the plant is cooled down and steam generator pressure decreases a runout condition could occur. In either case the failed open flow control valve results in the eventual loss of feed to the steam generator. The failure was not recovered.
Braidwood Unit 2	45789002	Feed control	FTO	The flow control valve for 2A steam generator would not fully open as a result of a defective circuit card. It was assumed that operators were not able to restore/control steam generator level until they manually opened the valve by bleeding off instrument air pressure to the valve operator. This action failed open the valve requiring operators to control flow to the steam generator using the pump discharge motor-operated valve. The failure was recovered.
Catawba Unit 1	41387026	Feed control	FTO	A switch that senses AFW flow to the steam generator failed causing the flow control valve to close. Operators were able to manually control flow. The failure was recovered.
Catawba Unit 1	41391015	Feed control	FTO	A flow control valve failed to control AFW flow rates as a result of dirt in the valve positioner. The failure was recovered using the pump discharge motor-operated valve to control flow. This event was classified as a failure as a result of operators having to use an alternative method to control AFW flow to a steam generator. The LER did not state any specific flow rates, however, it was assumed the flow rates to the steam generator were sufficiently reduced such that operator action was required.
Catawba Unit 1	41392008	Feed control	FTO	A motor-driven pump flow control valve failed to modulate closed to limit pump flow rate, resulting in a pump runout condition (the pump was discharging to a steam generator at 100 psig). Both motor-driven pumps were in a runout condition. However, only one flow control valve closed as required. The failure was judged as being recoverable.

Table C-1. (continued).

Plant Name	LER Number	Segment[a]	Failure Mode	Description
Catawba Unit 2	41488012	Feed control	FTO	AFW flow to a steam generators was reduced to less than 1/2 the normal flow rates as a result of Asiatic clams in the system. The reduction in flow rate was less than the minimum safety analysis values required to ensure adequate heat removal from the steam generator. The clams affected two feed control segments, thereby reducing the heat removal capability of the plant by one-half. This event was classified as a CCF for two segments during an operational mission, and a CCF of four segments for a risk-mission. The failure of the two additional segments for the risk-mission was assumed because at the time only one suction header was being supplied by service water, and given that the CST was isolated and the UST level indicator failed high, the other suction header would have shifted over the to the service water system fouling the other two feed segments with clams. The failure was not recovered.
Cook Unit 1	31589001	Feed control	FTO	The flow control valve for #2 S/G from the turbine-driven auxiliary feedwater pump moved in the closed direction as indicated by position indication lights, but failed to reach the proper intermediate position after receipt of a flow retention signal. The flow retention signal is generated upon a high auxiliary feedwater flow condition and acts to prevent pump runout by throttling the auxiliary feedwater isolation valves. Attempts to close the valve were unsuccessful until after the turbine-driven auxiliary feedwater pump was shutdown. The torque switches were set too low. The failure was not recovered.
Cook Unit 2	31693007	Feed control	FTO (CCF)	Two flow control valves throttled closed farther than required to maintain steam generator levels. The failure was recovered by operators taking control of the valves to maintain correct flow rates. The event was classified as a common cause failure.
Cook Unit 2	31695005	Feed control	FTO (CCF)	Two flow control valves for a motor-driven pump would not respond to close signals. Because the valves would not close to limit plant cooldown a control room operator shutdown the motor-driven pump discharging to the segments. The valve torque switches were set at too low a setting to allow proper operation. The failure was not recovered. This was classified as a common cause failure for the risk-mission only.
Millstone Unit 3	42389009	Feed control	FTO	Following a reactor trip, main feedwater isolated and the main feedwater pumps were shutdown. AFW automatically started as required . While attempting to control AFW flow, a flow control valve failed in an “as is” position resulting in the need for plant operators to terminate AFW flow to the steam generator and realign main feedwater. While restarting and aligning main feedwater, the feedwater isolation valve to one steam generator failed closed. This resulted in main feedwater supplying one steam generator while AFW supplied the other steam generator. The AFW valve failed to operate as a result of a malfunctioning control switch. The turbine-driven pump was also out of service for a surveillance test at the time of the demand. The failure was not recovered.
Oconee Unit 1	26989001	Feed control	FTO	The flow control valve for the 'A' steam generator failed to control level as a result of a failed driver card. To prevent overfeeding the steam generator the control room operator manually closed the valve and shutdown the turbine-driven pump per procedure. The failure was classified as recovered because the valve would respond to manual control signals.
Oconee Unit 1	26992004	Feed control	FTO	A flow control valve failed as a result of a malfunctioning solenoid valve. The valve failure resulted in no AFW flow to the “A” steam generator. The failure was judged as being recoverable.

Table C-1. (continued).

Plant Name	LER Number	Segment[a]	Failure Mode	Description
Oconee Unit 3	28791007	Feed control	FTO	A flow control valve failed to control steam generator level as a result of a malfunctioning solenoid valve. The failure disabled the automatic control feature of the valve requiring operator action to maintain adequate steam generator level. The failure was recovered.
St. Lucie Unit 2	38989007	Feed control	FTO	A motor-driven pump discharge valve would not respond to control signals as a result of a malfunction of the valve operator. The valve was mechanically bound such that flow was approximately half the required flow. The valve would not operate in either manual or automatic control. The failure was not recovered.
Seabrook	44390015	Feed control	FTO	The isolation valve to a steam generator closed as a result of high flow caused by both pumps running and supplying flow to the steam generator. The high flow isolation switch setpoints were raised 100 gpm to prevent recurrence. The failure was not recovered.
Sequoyah Unit 1	32789005	Feed control	FTO	A flow control valve did not adequately control steam generator level as a result of a disconnected feedback arm requiring the valve to be closed. The arm was not properly installed after maintenance. The failure was not recovered.
South Texas Unit 1	49890006	Feed control	FTO (2)	A test recirculation valve was inadvertently left open, resulting in no flow to a steam generator during an unplanned demand. Operators shut down the pump supplying the steam generator even though there was over 600 gpm indicated flow because level was not increasing. Operators then opened the cross-connect valves to supply flow from another AFW train, resulting in that train's flow being diverted out the test line also. Operators later realized that the test return line valve was open, and closed the valve. This event was classified as a failure of one segment without recovery followed by an error of commission failing the second segment that was recovered.
Surry Unit 2	28188004	Feed control	FTO (2) (CCF)	Low flow rates were observed to a steam generator during an unplanned demand, the actual flow rates were not given.. Testing after the event revealed no indication of the cause of the low flow rates. The inspection and testing included disassembly of six motor-operated valves, fiber-optic inspections, and the removal piping associated with the flow venturies. This event was classified as a common cause failure that was not recovered.
Vogtle Unit 1	42487009	Feed control	FTO (2) (CCF)	Two flow control valves to different steam generators failed to open resulting in no AFW flow to the steam generators as a result of a failed common relay for both. The failure was judged as being recoverable.
Vogtle Unit 1	42488008	Feed control	FTO	A malfunction in a control switch caused a flow control valve to fail during manual operation of the valve to control steam generator level. The failure was recovered.
Wolf Creek	48287037	Feed control	FTO (4)	Several minutes after a turbine-driven pump started a fire protection alarm was received in the turbine-driven pump room. Excessive steam was found in the room. With 3 of 4 steam generator water levels above the lo-lo level setpoint and the fourth steam generator water level recovering, the turbine-driven pump was shutdown and the steam supply valve closed. Fluctuations in steam generator levels were still occurring and although operators attempted to compensate they were unable to control steam generator levels using only the motor-driven pumps, resulting in an automatic start of the turbine-driven pump. The event was classified as a personnel error in operation of the feed control segments and was related to a turbine-driven pump failure.

Table C-1. (continued).

Plant Name	LER Number	Segment[a]	Failure Mode	Description
North Anna Unit 2	33993002	Motor-driven pump	EOC	The system was disabled by operator action with steam generator levels below the autostart setpoint in an effort to limit plant cooldown. The switches were left in the blocked position until a procedure reader noticed that the position was not as required. The failure was recovered.
Ginna	24490013	Motor-driven pump	FTR	A motor-driven pump failed after 20 minutes of operation. Steam was found escaping from the shaft packing with no flow indication. The cause was that the cross-connect valves were open with the other pump running. The other pump had 15 psig more discharge head, thus closing the pump discharge check valve. The minimum flow line is located after the discharge check valve. The failure was not recovered.
Surry Unit 2	28188010	Motor-driven pump	FTR (2) (CCF)	During an unplanned demand, AFW flow was reduced by over 1/3 to a steam generator. Inspection revealed metal pieces in the flow measuring orifice venturi to two steam generators. The metal pieces were from the pump impellers. All three pumps were inspected, and the channel ring vanes were missing pieces from each. The event was classified as a common cause for the risk-mission only that was not recovered.
Crystal River 3	30289023	Motor-driven pump	FTS	Two relays malfunctioned in the automatic initiation circuit, thus preventing an automatic start upon an initiation signal coincident with a degradation of off-site power. The relays were to energize when the diesel generator output breaker closed. The condition prevented only an automatic start. The pump was started manually after the vital-bus was re-energized. The failure was recovered.
Farley Unit 1	34889007	Motor-driven pump	FTS (2) (CCF)	Two motor-driven pumps failed to start manually because the control switches were incorrectly wired during a recent modification. The failure was recovered, and also classified as a common cause failure.
Indian Pt. Unit 2	24791001	Motor-driven pump	FTS	An incorrect amptector setpoint caused the power supply breaker to trip open two minutes after a successful start. The failure was not recovered.
Indian Pt. Unit 2	24792007	Motor-driven pump	FTS (2) (CCF)	The low-pressure shutdown switches for two motor-driven pumps were set at too high a value, resulting in both pumps not starting on demand during a steam generator low level transient. LER 24792017 is related to this failure. The failures were recovered by operator action and classified as a common cause failure.
Indian Pt. Unit 3	28687001	Motor-driven pump	FTS	Following a reactor trip from 100% power, a motor-driven pump tripped after it had previously automatically started as a result of a low steam generator water level condition. The pump trip was caused by actuation of the pump's over-current protection device. The discharge pressure limiter, which prevents the discharge pressure from decreasing below a predetermined setpoint, was found to be set low. This allowed higher than normal flow through the pump which in turn increased pump motor amperage and caused the over-current trip. The pump was restarted and operated in manual. The failure was recovered.
Indian Pt. Unit 3	28688002	Motor-driven pump	FTS	A failed flow controller caused a motor-driven pump's recirculation valve to remain open when it should have closed. The open recirculation valve resulted in a high flow condition and the pump's circuit breaker to trip on high current. The failure was recovered by operators taking manual control of the valves and restarting the pump.

Table C-1. (continued).

Plant Name	LER Number	Segment[a]	Failure Mode	Description
Millstone Unit 2	33687012	Motor-driven pump	FTS	A motor-driven pump failed to start as a result of a control panel ‘reset/override” switch. Although the switch appeared to be in the “start’ position, this spring-return-to-normal switch was found in an intermediate position, between contacts, preventing a start permissive signal. Operators were able to start the pump manually. The failure was recovered.
Robinson 2	26187018	Motor-driven pump	FTS	A motor-driven pump failed to start as a result of a mis-wired control circuit. The wiring problem was not discovered during the post-maintenance test. The failure was judged as being recoverable.
Millstone Unit 3	42387026	Motor-driven pump	MOOS	A motor-driven pump was out of service for maintenance prior to an unplanned demand. The failure was not recovered.
Oconee Unit 2	27094002	Motor-driven pump	MOOS	A motor-driven pump was out of service for a modification of the auto-initiation circuit at the time of an unplanned demand. The failure was recovered by manually starting the pump.
Sequoyah Unit 2	32888023	Motor-driven pump	MOOS	A motor-driven pump was out of service for testing at the time of an unplanned demand. The failure was not recovered.
Summer	39587015	Motor-driven pump	MOOS	A motor-driven pump was out of service for maintenance at the time of an unplanned demand. The failure was recovered.
Catawba Unit 2	41488012	Suction	FTO	An unplanned AFW demand occurred when the normal condensate storage tank suction supply to AFW was isolated because of a leak and the upper surge (backup source) level was not maintained above the minimum level for AFW pump operation, resulting in an automatic switchover of AFW suction to the assured source. The event was classified as a risk-mission failure that was recovered. This event led to a common cause failure of all four feed control segments that could not be recovered. The failure of the suction source is counted differently than the resulting failure of the feed control segment. This failure is not counted twice.
Calvert Cliffs Unit 2	31895002	Turbine steam supply	FTO	One of the turbine steam supply valves failed to open as a result of a degraded control switch. The failure was not recovered. The second turbine steam supply valve operated as designed. This event was counted as a failure of one of the two turbine steam supply valves.
Calvert Cliffs Unit 1	31792008	Turbine-driven pump	FTR	After 25 minutes of operation a high bearing temperature alarm was received in the control room. The turbine-driven pump was shutdown by the control room operator and another AFW pump was started. Subsequent investigation revealed a failed (wiped) inboard journal bearing. The turbine-driven pump was returned to an operable status two days later. The failure was not recovered.
Cook Unit 2	31691006	Turbine-driven pump	FTR	The governor was unable to control turbine speed under the steam pressure conditions experienced following a reactor trip. The turbine oversped as an operator was removing the turbine from service after completing an operational mission. While attempting to troubleshoot the cause of the overspeed trip, the governor would not respond to speed control signals from the control room. A new governor was installed. Based on the governor not responding to speed demand signals, it was judged to be unlikely to complete a 24 hour mission that would normally require a number of speed changes. The event was a failure of the risk-mission only that was not recovered. No times were provided in the LER for the mission duration or failure occurrence.
North Anna Unit 1	33888002	Turbine-driven pump	FTR	After 40 minutes of operation the turbine-driven pump tripped unexpectedly. The cause of the trip was a plug blew out of the trip limiter regulator valve striking the trip linkage, resulting in a turbine-driven pump trip. The failure was not recovered. The mission duration was not provided in the LER.

Table C-1. (continued).

Plant Name	LER Number	Segment[a]	Failure Mode	Description
Arkansas Unit 2	36889006	Turbine-driven pump	FTS	The turbine-driven pump oversped after 23 seconds of operation as a result of a defective EG-M control box. Operators were able to restart the turbine after the trip. The failure was recovered.
Beaver Valley Unit 2	41290008	Turbine-driven pump	FTS	The turbine-driven pump oversped and tripped during an autostart. Excessive stress on the tappet assembly due to poor alignment caused premature wear, which lowered the overspeed trip setpoint. The failure was not recovered.
Calvert Cliffs Unit 1	31787012	Turbine-driven pump	FTS	The turbine-driven pump oversped on a startup as a result of the overspeed trip linkage being out of adjustment. The failure was recovered.
Catawba Unit 2	41487029	Turbine-driven pump	FTS	The turbine-driven pump tripped on electronic overspeed during an autostart caused by improper travel adjustment of the governor. The failure was not recovered.
Comanche Peak Unit 1	44595003	Turbine-driven pump	FTS	The turbine-driven pump oversped on startup as a result of governor valve binding. The governor valve cam linkage was binding as a result of corrosion. The failure was not recovered.
Cook Unit 2	31691004	Turbine-driven pump	FTS	The turbine-driven pump oversped on a startup as a result of a spurious electronic overspeed. The trip was reset and the pump left in standby. The failure was judged as being recoverable.
Crystal River 3	30288002	Turbine-driven pump	FTS	The turbine-driven pump oversped on startup as a result of water accumulation in the steam supply lines. The bypass valve was not open sufficiently to prevent the buildup of condensate. The failure was judged as being recoverable.
Harris	40087035	Turbine-driven pump	FTS	The turbine-driven pump oversped and tripped on an automatic start as a result of water in the steam supply lines. The steam supply lines had been drained by plant personnel earlier in the shift. After the trip, the lines were drained again and considerable moisture was found. After draining the lines, the pump was successfully started three times under full flow conditions. It was determined that the water accumulation in the steam supply lines was the probable cause of the overspeed. The steam supply lines are normally depressurized but accumulates moisture from leakage past the isolation valves. Prior to the event, the moisture was being manually drained approximately every four hours. Because of the considerable amount of moisture drained prior to the re-start the failure was not considered recovered.
Harris	40089001	Turbine-driven pump	FTS	Water in the turbine steam supply lines caused the turbine to overspeed on startup. There was no additional information available in the LER to indicate that a second start would have experienced a similar trip so the failure was judged as being recoverable.
Harris	40089017	Turbine-driven pump	FTS	A spurious turbine trip occurred on startup from noise in the tachometer signal. The failure was judged as being recoverable.
St. Lucie Unit 2	38987003	Turbine-driven pump	FTS	A turbine-driven pump oversped on startup; no reason or corrective action was available in the LER. The failure was recovered.
St. Lucie Unit 2	38990001	Turbine-driven pump	FTS	A turbine-driven pump failed to start because the governor hydraulic oil was contaminated with foreign material. The failure was not recovered.
South Texas Unit 2	49989013	Turbine-driven pump	FTS	A turbine-driven pump was shut down after restoring steam generator level. A few minutes later, level was reduced to the autostart setpoint, resulting in a demand for the pump. The turbine tripped on overspeed during the start because the turbine was designed to start from a standstill and was still coasting down. The failure was judged as being recoverable.

Table C-1. (continued).

Plant Name	LER Number	Segment[a]	Failure Mode	Description
Surry Unit 1	28095001	Turbine-driven pump	FTS	The turbine-driven pump experienced speed oscillations on the ramp up to full speed and tripped 52 seconds later. The system was found to be dynamically unstable, resulting in the need to replace the governor. The failure was not recovered.
Vogtle Unit 1	42489005	Turbine-driven pump	FTS	Contaminated hydraulic oil caused the turbine-driven pump to overspeed because of sluggish governor response. The failure was not recovered.
Waterford 3	38287020	Turbine-driven pump	FTS	The turbine-driven pump oversped on a startup. The cause identified by the licensee was speculated to be the result of wear on the latch mechanism. The failure was not recovered.
Wolf Creek	48287037	Turbine-driven pump	FTS	The casing drain valve for a turbine driven pump was left open, resulting in a steam leak. The turbine was shut down because of the leak that caused the turbine-driven pump room to be flooded with steam and a fire alarm to be activated. The failure was recovered. Related to a feed control segment failure. This event was classified as a risk-mission failure only.
Harris	40089006	Turbine-driven pump	MOOS	The turbine-driven pump was out of service for maintenance at the time of an unplanned demand. The failure was not recovered.
McGuire Unit 1	36987009	Turbine-driven pump	MOOS	The turbine-driven pump steam supply valves were actuated, but the turbine did not start because the pump was in test at the time of an unplanned demand. The failure was not recovered.
Millstone Unit 3	42389009	Turbine-driven pump	MOOS	The turbine-driven pump was out of service for a surveillance test and unable to respond to an unplanned demand. The failure was judged as being recoverable.
Turkey Point Unit 4	25187001	Turbine-driven pump	MOOS	One train of AFW was out of service for testing at the time of an unplanned demand. The failure was judged as being recoverable.
Turkey Point Unit 4	25192007	Turbine-driven pump	MOOS	One train of AFW was out of service for a post-maintenance test at the time of an unplanned demand. The failure was judged as being recoverable.

a. For the events where the diesel-, motor-, or turbine-driven pump segments failed to complete an operational or risk-based mission the run time is identified in the description of the event, if the time was provided in the LER. Several failures classified as failure to run did not identify a run time prior to failure and therefore no run time is listed.

Appendix D

Supporting Information of AFW System Unreliability Analysis

Appendix D

Supporting Information of AFW System Unreliability Analysis

D-1. Common Cause Failures

CCF data collection and analysis of the AFW system was conducted in several stages and accomplished in conjunction with the CCF Database[D-1] program. First, the LERs (both unplanned demand and surveillance test for the 1987–1995 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 AFW system included events identified in the 1987–1995 time period that contributed to failure of redundant segments. Based on the 1987–1995 unplanned demand data, CCF events were identified for the motor-driven pump trains failing to start; the pumping unit (independent of driver) failing to run; and, the injection headers failing to operate. To further evaluate the susceptibility of AFW to CCF, the surveillance test data contained in the LERs were screened to identify additional CCF mechanisms. One additional event, failure of the turbine train steam supply valves to open, was identified in the surveillance test data as a viable CCF failure mechanism.

The Alpha Factor method, which is supported by the CCF Data Collection and Analysis System (see Reference D-1), 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 AFW system study needs, and (2) supports an uncertainty analysis by estimating CCF uncertainties.

The CCF basic event probability is calculated according to the following equation:

Probability of CCF = $\alpha_{k/n} \times Q_t$.

The Alpha factor is denoted by $\alpha_{k/n}$ where k represents the number of redundant components out of the common cause group of size n that fail due to common cause. When AFW train failure criteria requires all trains to fail, k=n. The probability equation for estimating the CCF is based on a staggered testing scheme, which appropriately represents current plant testing procedures. The total failure rate (denoted by Q_t) for each segment's failure mode(s) is calculated from all the independent and common cause events identified in the unplanned demands used in this study.

Alpha factors were quantified by using the CCF Data Collection and Analysis System. First, independent counts that matched the selected years and component failure modes of interest to the AFW study were calculated, independent of the CCF data analysis code, from the CCF database that contains both independent and CCF events. Within the code, CCF events that matched the selected years and component failure modes of interest to the AFW study were selected from a generic list of CCF events and the resulting independent counts were manually entered. Impact mapping, one of the options in the CCF analysis code, was used to provide a consistently larger set of data to estimate CCF parameter results. Total failure rates, used in developing basic event probabilities, were estimated from the 1987–1995 unplanned demand data used in this study.

Two CCF basic events, typically accounted for in earlier AFW unreliability models, were not included in this AFW study. Specifically, CCF mechanisms that failed check valves or caused steam binding of the pump trains from back leakage of hot water into the AFW system were not identified in the 1987–1995 experience (either the unplanned demand or surveillance test data) for the AFW system. This may be a consequence of the NRC IE Bulletin 85-01 issued in October 1985, Steam Binding of Auxiliary Feedwater Pumps[D-2] that detailed actions to address steam binding concerns. Prior to the issuance of IE Bulletin 85-01, there were steam binding events reported where hot water leaked into the AFW systems.

This was not the case for turbine steam supply isolation valves. There were no observed failures in the unplanned demand data for the steam supply isolation valves to the AFW turbine(s). However, this type of CCF was identified in the surveillance data. Therefore, CCF of the turbine steam supplies is included in the model. However, for the quantification (i.e., Q_t associated with the steam supply) of AFW unreliability, only failure data identified during unplanned demands are used. In addition, CCF modeling of the turbine trains failing to start were not modeled since no CCF events were identified in the failure data for this failure mode.

The Alpha factors calculated from the CCF Data Collection and Analysis System are presented in Table 3 of the main report. In addition to the CCF failure modes identified in the 1987–1995 experience, the Alpha factors for the turbine failing to start are included in Table 3. The turbine failing to start Alpha factors are provided to complement the turbine information although not found in the 1987–1995 experience. They are intended to provide the reader and user of this document with a consistent set of CCF parameters for the AFW turbine train.

The CCF failure probability estimates calculated by the Alpha factor methodology were compared to direct or simple estimates derived from the 1987–1995 experience for demonstrating the reasonableness of the Alpha factor estimates. The 1987–1995 estimates were calculated from CCF events and the number of demands. The direct estimates considered only lethal failures, that is, total loss of all redundancy. Furthermore, the estimates are based on the unrecovered total failure rate for the failure modes identified above. The means and bounds derived from the 1987–1995 experience (denoted 1987–1995 Exp. in Figure D-1) are derived from the number of opportunities for the particular failure mode and the lethal events observed. The opportunities or demands used in the "1987–1995 Exp." estimate consist of the individual segment demands identified for the particular failure mode since a successful train demand eliminates the opportunity for a lethal CCF. Therefore, the CCF opportunities are simply the demands used in calculating the independent failure rate estimates presented in Table 2 of the main report. There was only one lethal unrecovered CCF event identified in the 1987–1995 experience. This event was related to the two motor-driven pump trains failing to start. For the remaining failure modes, no unrecovered lethal CCF events were identified.

Figure D-1 provides a plot of the estimates and associated uncertainties calculated by Alpha factor methodology and those using the 1987–1995 unplanned data directly. As seen in the plot, the estimates calculated by Alpha factor methods are lower than the estimates derived directly from the 1987–1995 experience. The Alpha factor method was chosen over the direct method for several reasons. First, the data used for the calculating the CCF estimates directly is limited to only lethal events. That is, only lethal CCF events found in the unplanned demand data are used in the direct calculation which ignores the effects of partial system failures due to CCF. The CCF Data Collection and Analysis system contains partial event information thereby providing a richer source of information for evaluating and quantifying CCF. Secondly, the CCF estimates computed directly did not differentiate with regard to the common cause group size thereby providing an estimate without regard for group size. As a result, applying a single estimate to a system with different levels of redundancy is not appropriate. As shown in Figure D-1, the direct (i.e., 1987–1995 Exp.) estimates are conservative compared to the Alpha factors.

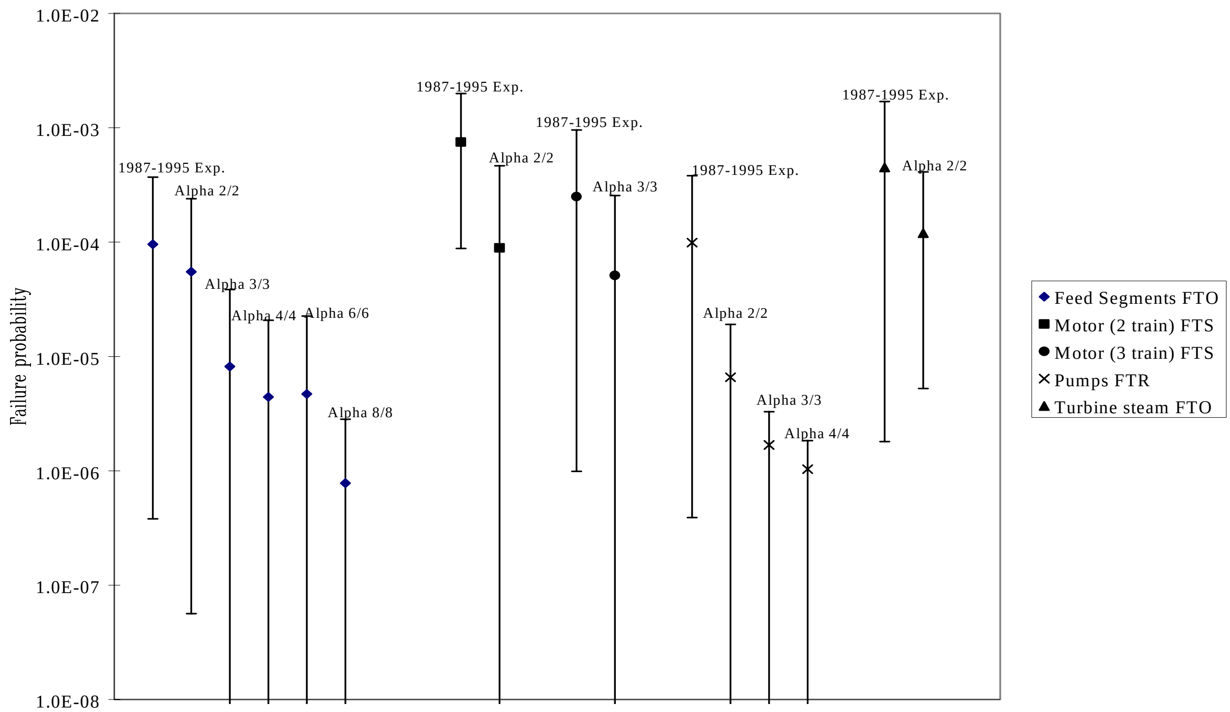

Figure D-1 A plot of CCF estimates and uncertainties calculated directly from the 1987–1995 experience and the CCF estimates calculated by the Alpha factor methodology.

D-2. Within Design Class Differences

The AFW design classes were categorized first by number of steam generators, then by number of pump trains, and finally by number of motor trains. To better understand inter-design class differences, the AFW system models for all of the operating plants were quantified using the mean of the generic Bayes probability distribution for the failure modes listed in Tables 3 and 4 of the report body. By using the generic mean, plant configurations and modeling differences within a design class could readily be identified by plotting the estimates by AFW design class. For the design classes showing variability, the AFW P&ID schematics and models were examined to determine the physical or modeling differences causing the variability. Figure D-2 is a plot of the results of the analysis. The figure shows that within a design class there are some noticeable, although not significant, differences in system probabilities that are attributed to AFW system design and modeling. These differences are discussed below.

Design Class 1 (1M, 1T, 2SG)—Three different system probabilities were obtained for Design Class 1 plants. Two of the results were very close (i.e., 6.4E-05 and 7.0E-05). The difference between these two clusters of plants is due to the modeling of the feed control segments. Both groups of plants have redundant feed injection paths per steam generator. However, the plants with the 7.0E-05 value (Prairie Island 1 & 2) have the injection paths feeding into a common header that contains a motor-operated isolation valve prior to entering the steam generator. Therefore, these plants have the single cut set(second order) of the two feed isolation segments. The plants with the 6.4E-5 value (Arkansas Nuclear One 1 & 2, Palo Verde 1, 2, &3, Crystal River) contain only the two redundant feed control segments per steam generator. Therefore, these plants do not have the single cut set(second order) of the two feed isolation segments. The extra cut set causes the overall system probability to be slightly higher.

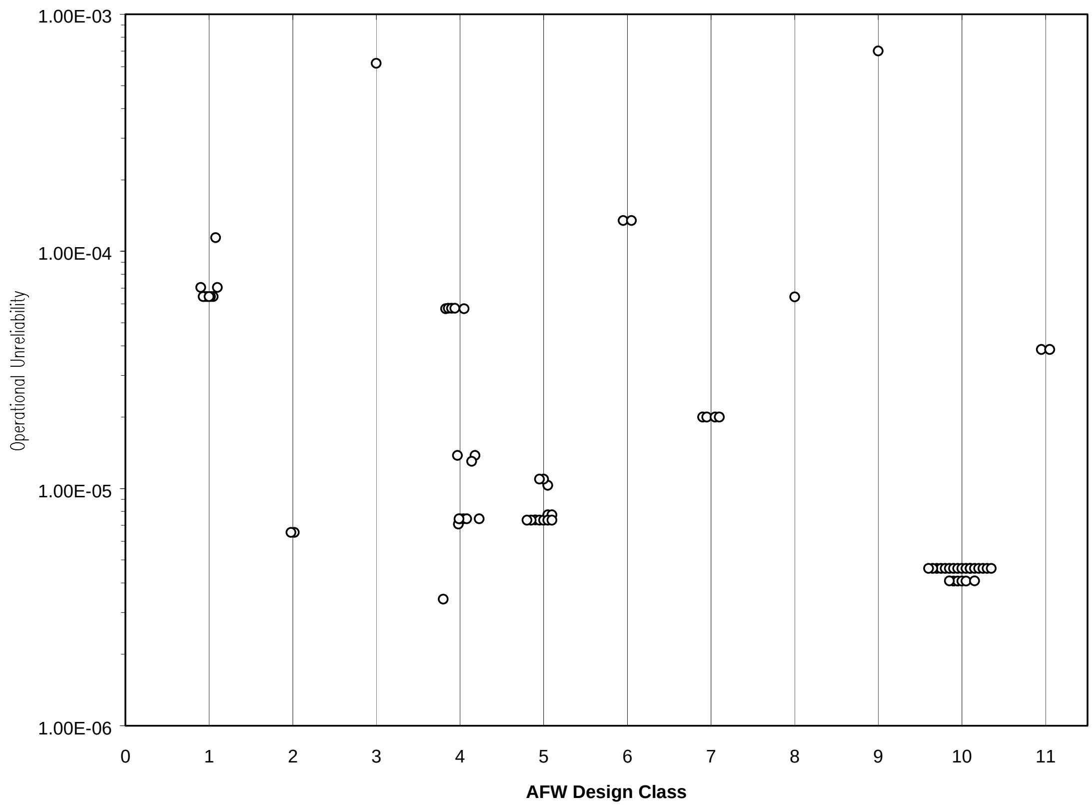

Figure D-2. A plot of the AFW operational unreliability [calculated with failure mode estimates for all plants set to the mean of the generic (industry) Bayes probability distribution] distinguishing within design class modeling differences.

The third cluster (only one plant; Fort Calhoun) obtained from the Design Class 1 analysis is considerably higher. The higher system probability associated with this plant is attributed to the feed control segments. The plant's pump trains discharge into a common header and only one injection path per steam generator. The common cause failure of the feed control segments for Fort Calhoun used a Alpha factor for the failure of 2-of-2 feed control segments The plant configuration associated with the other two groups used a common cause failure of the feed control segments with an Alpha factor for the failure of 4-of-4 feed control segments. The use of the different Alpha factors because of a different number of feed segment paths is the primary reason for the different system probabilities.

Design Class 2 (1M, 2T, 2SG)—There are only two plants in this design class. The two plants are Calvert Cliffs 1 and 2 which are modeled the same.

Design Class 3 (2T, 2SG)—There is only one plant is this design class.

Design Class 4 (2M, 1T, 2SG)—Figure D-1 identifies four distinct system clusters within this design class. For one cluster (Kewaunee), the feed control segments are modeled as part of the pump train segment. The feed control was contained in the pump train since the pump/feed segment represented a series system of components. As a result, no common cause failure of the feed segments was modeled for this plant.

The next cluster (St. Lucie, Ginna, Pt. Beach) has redundant feed control segments per steam generator modeled. Therefore, the system level cut set for the feed control segment is fourth order (barely above the 1.0E-12 probability cut off). The Alpha factor for the feed control segments at these plants is failure of 4-of-4 feed control segments.

The third cluster of plants (San Onofre and Waterford), second cluster from the top, have redundant feed injection paths per steam generator. However, San Onofre has the injection paths feeding into a common header that contains a motor-operated isolation valve prior to entering the steam generator. Therefore, San Onofre has an additional cut set (second order) involving failure of the two feed isolation segments. This modeling provides an extra cut set which causes this plant to have a slightly higher system probability than remaining plants in this cluster. The plants in this cluster use the same Alpha factor (failure of 4-of-4 feed control segments).

The fourth cluster of plants (Oconee 1, 2, & 3, Millstone 2, Three Mile Island), top cluster from top, have single feed control segments to each steam generator. However, the Alpha factor for this cluster is failure of 2-of-2 feed control segments.

Design Class 5 (2M, 1T, 3SG)—The differences between the two clusters within this design class is due to the number of feed control segments. There were two different common cause feed control segments modeled for these plants. They were 3-of-3 feed control segments (for the plants having only a single feed injection path per steam generator) and 6-of-6 feed control segments (for the plants having only a redundant feed injection paths per steam generator). These two plant configurations can be discerned from Figure D-1. An additional model difference is attributed to the success criteria. Farley 1 and 2 are the only plants in this class that use an AFW success criterion of 2-of-3 steam generators for success. The remaining plants in this design class use a success criterion of 1-of-3 steam generators. Farley 1 & 2 has 6 feed control segments (i.e., two per steam generator).

The plants which utilize a 3-of-3 feed control segment common cause value model their feed control segments slightly different based upon plant configuration. These plants either had the feed control segments coming directly from a dedicated pump train or off a common header fed by the pump trains. This modeling caused the slight difference in system probabilities for this cluster.

Design Class 6 (3T, 3SG)—There are only two plants in this design class. The two plants are Turkey Point 3 and 4 which are modeled the same.

Design Class 7 (1M, 1T, 4SG)—There are four plants in this design class. The plants are Byron 1 and 2 and Braidwood 1 and 2 there is essentially no difference between the plants.

Design Class 8 1M, 1T, 4SG)—There is only one plant in this class.

Design Class 9 (2T, 4SG)—There is only one plant in this class.

Design Class 10 (2M, 1T, 4SG)—There is essentially no difference in the system probabilities for all AFW configurations in Design Class 10. The slight difference that is shown in Figure D-1 is attributed to the feed control segment modeling. The two clusters have different plant configurations for the feed control segment associated with the motor-driven pumps. For the one cluster (system probability of 4.6E-6), the motor pump trains discharge into a common header. The other group (system probability of 4.1E-6) has each pump train dedicated to a feed control segment which feeds the steam generators. This subtle difference results in a slightly different system probability. All designs in this class utilize the same Alpha factor for the failure of 8-of-8 feed control segments.

Design Class 11 (3M, 1T, 4SG)—There are only two plants in this design class. The two plants are South Texas 1 and 2 which are modeled the same.

D-3. Run Time Calculations

Table D-1 provides a summary of the run time estimation. Two average run times were calculated for each pump type. An average run time was calculated for those events for which AFW system/train failures were observed. A second average run time was computed for those events for which no AFW system/train failures were observed. These averages were then used to estimate run times for pump demands with unknown run times. Average run times with and without failures were calculated since LERs reporting AFW failure may be more likely to document run times and these times might be shorter than otherwise because of the failures. No statistical difference was found for the two sets of 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 and Section E-3 of Appendix E provides the additional information about the run time evaluation.

The cumulative run time (actual plus projected) based on the 1,987 unplanned demands for the motor-driven pump trains is approximately 4,618 hours. For the turbine-driven pump train, the cumulative run time (actual plus projected) was 371 hours based on 583 unplanned demands. For the diesel-driven pump train, the 65 unplanned demands resulted in 42 cumulative hours of run time (actual plus projected).

Table D-1. Run times (hours) estimated from the AFW unplanned demands.

	Pump Type		
Run Time Events	Motor	Turbine	Diesel
Number known with failures[a]	22 (38.6 hr)	10 (9.3 hr)	3 (2.6 hr)
Number known without failures[b]	217 (511.5 hr)	89 (54.9 hr)	13 (8.4 hr)
Total known run time (hr)	550	64	11
Average known run time (hr)			
with failures	1.76	0.93	0.86
without failures	2.36	0.62	0.64
Number unknown with failures (projected hours)	87 (153 hr)	28 (26 hr)	0
Number unknown without failures (projected hours)	1,661 (3,915 hr)	456 (281 hr)	49 (31 hr)
Projected unknown run time (hr)	4,068	307	31
Total projected run time (hr)	4,618	371	42

a. The first value represents the number of AFW system/train events in which the given pump type was running when a component failure, pump or otherwise, resulted in the AFW system operation being terminated and the AFW system/train run time was specified in the LER. For example, there were 10 events in which the turbine pump was running when a failure (only three of the ten involved a turbine pump failure while seven were failures associated with a component other than a turbine pump) resulted in the AFW system/train failure.

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

D-4. Failure Rates based on 1987–1995 Experience for Comparison with PRA/IPE Results

Table D-2 provides the various failure rates used in calculating the AFW unreliability estimates used for comparison with PRA/IPE results.

Table D-2. AFW system failure mode data and Bayesian probability information normalized for comparison to PRA/IPE information. The common cause Alpha factors are presented in Table 3 of the main report.

Failure Mode	f [a]	d [a]	Modeled Variation	Distribution	Bayes Mean and 90% Interval[b]
Unrecovered MOOS-M			Sampling	Beta(2.4, 2080.6)	(2.4E-04, 1.1E-03, 2.5E-03)
Maintenance-out-of-service while not shut down — motor train (MOOS-M)	4	1,995	Sampling	Beta(4.5, 1991.5)	(8.3E-04, 2.3E-03, 4.2E-03)
Failure to recover MOOS-M	2	4	Sampling	Beta(2.5, 2.5)	(1.7E-01, 5.0E-01, 8.4E-01)
Unrecovered MOOS-T			Plant	Beta(0.5, 105.1))	(1.7E-05, 4.6E-03, 1.8E-02)
Maintenance-out-of-service while not shut down — turbine train (MOOS-T)	5	602	Plant	Beta(0.6, 70.4)	(5.8E-05, 8.0E-03, 2.9E-02)
Failure to recover MOOS-T	3	5	Sampling	Beta(3.5, 2.5)	(2.6E-01, 5.8E-01, 8.7E-01)
Unrecovered FTO-SUC			Sampling	Beta(0.4, 1276.4)	(5.5E-07, 3.4E-04, 1.4E-03)
Failure to operate, suction path faults — (FTO-SUC)	1	1,116	Sampling	Beta(1.5, 1115.5)	(1.6E-04, 1.3E-03, 3.5E-03)
Failure to recover suction path faults FTO-SUC	0	1	Sampling	Beta(0.5, 1.5)	(1.5E-03, 2.5E-01, 7.7E-01)
Unrecovered FTS-ST			Sampling	Beta(1.2, 1156.1)	(7.5E-05, 1.0E-03, 2.9E-03)
Failure to open, turbine steam supply — (FTS-ST)	1	1,108	Sampling	Beta(1.5, 1107.5)	(1.6E-04, 1.4E-03, 3.5E-03)
Failure to recover turbine steam supply FTS-ST	1	1	Sampling	Beta(1.5, 0.5)	(2.3E-01, 7.5E-01, 1.0E+00)
Unrecovered FTS-M			Plant	Beta(0.1, 114.1)	(<1.0E-08, 8.1E-04, 4.7E-03)
Failure to start, motor pump/valve train path — (FTS-M)	6	1,993	Plant	Beta(0.1, 36.3)	(<1.0E-08, 3.8E-03, 2.1E-02)
Failure to recover from motor FTS-M	1	6	Sampling	Beta(1.5, 5.5)	(3.0E-02, 2.1E-01, 5.0E-01)
Unrecovered FTS-T			Plant	Beta(4.3, 308.7)	(4.9E-03, 1.4E-02, 2.6E-02)
Failure to start, turbine pump/valve train path — (FTS-T)	17	597	Plant	Beta(7.2, 245.3)	(1.4E-02, 2.9E-02, 4.8E-02)
Failure to recover from turbine FTS-T	8	17	Sampling	Beta(8.5, 9.5)	(2.9E-01, 4.7E-01, 6.6E-01)
Unrecovered FTS-D			Sampling	Beta(0.4, 75.2)	(9.5E-06, 5.7E-03, 2.3E-02)
Failure to start, diesel pump/valve train path — (FTS-D)	1	65	Sampling	Beta(1.5, 64.5)	(2.7E-03, 2.3E-02, 5.9E-02)
Failure to recover from diesel FTS-D	0	1	Sampling	Beta(0.5, 1.5)	(1.5E-03, 2.5E-01, 7.7E-01)
Unrecovered FTS-M			Sampling	Gamma(1.2, 4818.7)	(1.8E-05, 2.4E-04, 6.9E-04)
Failure to run, motor pump/valve train path — (FTR-M)	1	4,618 hours	Sampling	Gamma(1.5, 4618.5)	(3.8E-05, 3.3E-04, 8.5E-04)
Failure to recover motor pump/valve train path FTR-M	1	1	Sampling	Beta(1.5, 0.5)	(2.3E-01, 7.5E-01, 1.0E+00)
Unrecovered FTR-T			Sampling	Gamma(3.1, 377.1)	(2.3E-03, 8.2E-03, 1.7E-02)
Failure to run, turbine pump/valve train path — (FTR-T)	3	371 hours	Sampling	Gamma(3.5, 371.5)	(2.9E-03, 9.4E-03, 1.9E-02)
Failure to recover turbine pump/valve train path FTR-T	3	3	Sampling	Beta(3.5, 0.5)	(5.6E-01, 8.8E-01, 1.0E+00)

Table D-2. (continued).

Failure Mode	f [a]	d [a]	Modeled Variation	Distribution	Bayes Mean and 90% Interval[b]
Unrecovered FTR-D			Sampling	Gamma(1.2, 44.2)	(2.0E-03, 2.7E-02, 7.5E-02)
Failure to run, diesel pump/valve train path — (FTR-D)	1	42 hours	Sampling	Gamma(1.5, 42.4)	(4.2E-03, 3.5E-02, 9.2E-02)
Failure to recover diesel pump/valve train path FTR-D	1	1	Sampling	Beta(1.5, 0.5)	(2.3E-01, 7.5E-01, 1.0E+00)
Unrecovered FTO-INJ			Plant	Gamma(0.2, 95.2)	(1.5E-08, 2.4E-03, 1.2E-02)
Failure to operate feed control/injection header — (FTO-INJ)	22	5,226	Plant	Beta(0.4, 97.1)	(6.2E-06, 4.3E-03, 1.8E-02)
Failure to recover feed control/injection header FTO-INJ	11	22	Plant	Beta(0.2, 0.2)	(1.4E-05, 5.6E-01, 1.0E+00)
Unrecovered total FTS probability for motor unit only (MDPS-FTS)			Plant	Beta(0.07, 23.0)	(<1.0E-08, 3.1E-03, 1.8E-02)
Total FTS probability for motor unit only (MDPS-FTS)	10	1,993	Plant	Beta(0.1, 14.2)	(<1.0E-08,6.3E-03, 3.7E-02)
Failure to recover MDPS-FTS CCF events	1	2	Sampling	Beta(1.5, 1.5)	(9.7E-01, 5.0E-01, 9.0E-01)
Unrecovered total FTR rate for pump unit only (PMPS-FTR)			Plant	Gamma(0.04, 73.0)	(<1.0E-08, 5.1E-04, 2.4E-03)
Total FTR rate for pump unit only (PMPS-FTR)	3	5,032 hours	Plant	Gamma(0.04, 61.0)	(<1.0E-08, 6.8E-04, 3.3E-03)
Failure to recover PMPS-FTR CCF events	1	1	Sampling	Beta(1.5, 0.5)	(2.3E-01, 7.5E-01, 1.0E+00)
Unrecovered total FTO-INJ probability (DIS-SEG)			Plant	Beta(0.4, 141.3)	(4.2E-06, 3.0E-03, 1.2E-02)
Total FTO-INJ probability (DIS-SEG)	32	5,226	Plant	Beta(0.5, 87.8)	(3.0E-05, 5.9E-03, 2.2E-02)
Failure to recover FTO-INJ CCF events	2	4	Sampling	Beta(2.5, 2.5)	(1.7E-01, 5.0E-01, 8.4E-01)
Total FTS-ST probability (TD-QT-STM)	1	1,108	Sampling	Beta(1.5, 1107.5)	(1.6E-04, 1.4E-03, 3.5E-03)

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

b. The values in parentheses are the 5% uncertainty limit, the Bayes mean, and the 95% uncertainty limit.

D-5. Summary of Cut Set Contribution and Failure Rates Based on IPEs and 1987–1995 Experience for the Eleven Reference Plants

To determine the reasons for the differences between the IPEs and the those based on the 1987–1995 experience, the cut sets for the 11 reference plants (both IPE and 1987–1995 experience) generated for this study were compared with each other. Table D-3 of provides a summary tabulation of the cut set review.

In addition to a review of the AFW system cut sets, the IPEs associated with the 11 plants in the design classes were reviewed concerning pump train failure data for failure to start and failure to run. Table D-4 provides a compilation of the review.

Table D-3. Summary comparison of cut set contribution based on IPE failure probabilities and failure probabilities estimated from the 1987–1995 experience and using the AFW fault tree shown in Figure 4 for the 11 design classes.

Design Class	Reference Plant	1987–1995 Exp. ÷ PRA/IPE	Contributors to AFW Unreliability Based on the Fault Tree Model in Figure 4 and Using IPE Failure Data	Contributors to AFW Unreliability Based on the Fault Tree Model in Figure 4 and Using 1987–1995 Experience
1 (1M, 1T, 2SG)	Crystal River 3	3	92%—multiple independent failures of turbine and motor train (1.4E-04) 6%—CCF of steam generator check valve (7.7E-06) 2%—CCF of turbine steam supply and ind. motor failures (4.2E-06)	84%—multiple independent failures of turbine and motor train (2.3E-03). Probability of turbine failing to run is a significant contributor, approximately 0.18 compared to IPE estimate of 9.1E-04. 12%—CST suction failure (3.4E-04) 4%—CCF of pumps failing to run (9.6E-05)
2 (1M, 2T, 2SG)	Calvert Cliffs 1	25	47%—CCF of turbine and ind. motor failures (1.0E-05) 13%—CCF of steam generator check valve (2.7E-06) 33%—multiple independent failures of turbine and motor train (9.1E-06) 7%—CCF of turbine steam supply and ind. motor failures (3.7E-06)	51%—CST suction failure (3.4E-04) 45%—multiple independent failures of turbine train (2.7E-04). Probability of turbine failing to run is a significant contributor, approximately 0.18 compared to IPE estimate of 1.7E-02. 4%—CCF of pumps failing to run (2.6E-05)
3 (2T, 2SG)	Davis-Besse	4	72%—multiple independent failures of turbine and motor train (8.4E-03) 19%—CCF of turbine pumps (1.2E-03) 9%—CCF of turbine drivers (5.6E-04)	98.5%—multiple independent failures of turbine and motor train (3.8E-02). Probability of turbine failing to run is a significant contributor, approximately 0.18 compared to IPE estimate of 3.1E-02. 1%—CST suction failure (3.4E-04) 0.5%—CCF of pumps failing to run (1.3E-04); CCF of steam supply (1.1E-04)

Table D-3. (continued).

Design Class	Reference Plant	1987–1995 Exp. ÷ PRA/IPE	Contributors to AFW Unreliability Based on the Fault Tree Model in Figure 4 and Using IPE Failure Data	Contributors to AFW Unreliability Based on the Fault Tree Model in Figure 4 and Using 1987–1995 Experience
4 (2M, 1T, 2SG)	St. Lucie 1	1.5	35%—multiple independent failures (1.1E-05) 30%—CCF of steam generator check valve (9.0E-06) 26%—motor suction check valve failure and ind. turbine failures (7.6E-06) 9%—CCF of motor failing to start and ind. turbine failures (2.7E-06); CCF of discharge segment (3.0E-07)	91%—CST suction failure (3.4E-04) 4%—CCF of pumps failing to run (1.5E-05) 0.5%—CCF of motors failing to start and an ind. failure (1.1E-06); CCF of discharge segment (9.9E-07) 5%—multiple independent failures of turbine and motor train (1.7E-05).
5 (2M, 1T, 3SG)	Farley 1	5	34%—multiple independent failures (1.4E-06) 66%—CCF of motors failing to start and ind. turbine failures (1.4E-06);	99%—CST suction failure (3.4E-04) 1%—CCF of pumps failing to run (2.7E-06); CCF of discharge segment (1.0E-06)
6 (3T, 3SG)	Turkey Point 3	33	71%—CCF of turbines failing to start (1.7E-04) 28%—CCF of turbines failing to run (6.4E-05) 1%—multiple independent failures (3.0E-06)	93%—multiple independent failures of turbines (6.8E-03). Probability of turbine failing to run is a significant contributor (71% of unreliability) approximately 0.17 compared to IPE estimate of 2.1E-03. 5%—CST suction failure (3.4E-04) 2%—CCF of steam supply (1.1E-04); CCF of pumps failing to run (3.1E-05)
7 (1M, 1D, 4SG)	Braidwood 1	44	100%—multiple independent failures of motor and diesel (4.1E-05)	90%—multiple independent failures of motor and diesel (2.7E-03). Probability of diesel failing to run is a significant contributor (68% of unreliability) approximately 0.47 compared to IPE estimate of 8.0E-4. 8%—CST suction failure (3.4E-04) 2%—CCF of pumps failing to run (9.0E-05)

Table D-3. (continued).

Design Class	Reference Plant	1987–1995 Exp. ÷ PRA/IPE	Contributors to AFW Unreliability Based on the Fault Tree Model in Figure 4 and Using IPE Failure Data	Contributors to AFW Unreliability Based on the Fault Tree Model in Figure 4 and Using 1987–1995 Experience
8 (1M, 1T, 4SG)	Seabrook	3	95%—multiple independent failures of motor and turbine (2.4E-04) 4%—CCF of pumps failing to start (1.0E-05) 1%—CCF of pumps failing to run (3.1E-06)	48%—multiple independent failures of motor and turbine (3.2E-04). Probability of turbine failing to run is a significant contributor, approximately 9.2E-02 compared to IPE estimate of 9.0E-03. 47%—CST suction failure (3.4E-04) 5%—CCF of pumps failing to run (3.0E-05); CCF of discharge segments (5.1E-06)
9 (2T, 4SG)	Haddam Neck	47	47%—CCF of turbines failing to start (3.9E-04) 9%—CCF of turbines failing to run (7.2E-05) 5%—CCF of steam supply (4.2E-05) 39%—multiple independent failures (3.3E-04)	98%—multiple independent failures of turbine train (3.9E-02). Probability of turbine failing to run is a significant contributor, approximately 0.18 compared to IPE estimate of 7.2E-03. 1%—CST suction failure (3.4E-04) 0.5%—CCF of pumps failing to run (1.3 E-04); CCF of steam supply (1.1E-04)
10 (2M, 1T, 4SG)	Salem 1	13	46%—CCF of pumps (6.5E-06) 28%—CCF of motor pumps failing to start and ind. Turbine failures (3.9E-06) 4%—CCF of motor train discharge segment AOVs and ind. turbine failures (5.4E-07) 22%—multiple independent failures (3.4E-06)	89%—CST suction failure (3.4E-04) 5%—CCF of pumps failing to run (1.9E-05); CCF of motors failing to start and ind. turbine failures (1.2E-06) 6%—multiple independent failures of turbine and motor train (2.4E-05). Probability of turbine failing to run is 0.18 compared to IPE estimate of 1.2E-03.

Table D-3. (continued).

Design Class	Reference Plant	1987–1995 Exp. ÷ PRA/IPE	Contributors to AFW Unreliability Based on the Fault Tree Model in Figure 4 and Using IPE Failure Data	Contributors to AFW Unreliability Based on the Fault Tree Model in Figure 4 and Using 1987–1995 Experience
11 (3M, 1T, 4SG)	South Texas 1	31	74%—CCF of discharge segment MOVs (9.1E-06) 23%—CCF of motor pumps failing to start and ind. Turbine failures (2.8E-06) 1%—CCF of pumps (1.7E-07) 1%—CCF of steam generator check valves (9.5E-08)	87%—CST suction failure (3.4E-04) 11%—CCF of discharge segment MOVs (4.3E-05); CCF of motor pumps failing to start and ind. turbine failures (3.9E-07) 2%—CCF of pumps failing to run (6.1E-06).

Table D-4. Pump train information (failure to start and failure to run) for the 11 AFW design classes extracted from the IPEs.

Design Class	Reference Plant	IPE Generic (or Prior) Mean	IPE Estimate Used in Quantification	1987–1995 Experience	IPE Information Pertaining to Failure Data and Estimates
1 (1M, 1T, 2SG)	Crystal River 3	MDP FTS—4.7E-03 FTR—2.8E-05 TDP FTS—3.2E-02 FTR—1.9E-03	MDP FTS—1.3E-03 FTR—1.4E-05 TDP FTS—1.4E-02 FTR—3.8E-05	MDP FTS—4.6E-03 FTR—2.4E-04 TDP FTS—1.5E-02 FTR—8.2E-03	Plant-specific values used; no Bayesian updating. Standby components (primarily pumps) operating logs were reviewed and an average operating time per demand was calculated.
2 (1M, 2T, 2SG)	Calvert Cliffs 1	MDP FTS—2.4E-03 FTR—3.4E-05 TDP FTS—3.3E-02 FTR—1.0E-03	MDP FTS—1.3E-03 FTR—5.3E-06 TDP FTS—1.2E-02 FTR—7.1E-04	MDP FTS—6.1E-04 FTR—2.4E-04 TDP FTS—1.5E-02 FTR—8.2E-03	IPE reports using a combination of generic and plant-specific data. PLG generic base (PLG-0500), NUREG-4639 (NUCLARR), EPRI, NUREGs 1205, 1363, & 1635, IEEE-500, WASH-1400, & BG&E data using engineering judgment. Plant-specific used on all important components per NUREG 1335. Plant-specific obtained through NPRDS. Posterior distribution obtained by a single-stage Bayesian update of BG&E data. The MDP FTR posterior obtained using a gamma-poisson conjugate estimation. IPE plant-specific MDP FTS 4 failures in 3,604 demands (1.1E-3); FTR 2 failure in 377,897 hours (5.3E-6). IPE plant-specific TDP FTS 7 failures in 726 demands (9.6E-03); FTR 0 failures in 182 hours (0.0E+00).
3 (2T, 2SG)	Davis-Besse	*MDFP* FTS—3.1E-03 FTR—2.4E-05 TDP FTS—2.1E-02 FTR—1.3E-03	*MDFP* FTS—6.2E-03 FTR—2.4E-05 TDP FTS—2.1E-02 FTR—1.3E-03	*MDFP* FTS—NA FTR—NA TDP FTS—1.3E-02 FTR—8.2E-03	Bayesian update of motor-driven feed pump (MDFP): FTS—2 failures in 72 demands (2.8E-2), FTR—0 failures in 597 hours (0.0E+00). No AFW plant-specific collected; system not risk significant based on previous PRAs and lack of reliable information.
4 (2M, 1T, 2SG)	St. Lucie 1	MDP FTS—4.8E-03 FTR—8.5E-05 TDP FTS—2.6E-02 FTR—8.9E-05	MDP FTS—1.8E-03 FTR—6.9E-05 TDP FTS—2.6E-02 FTR—8.9E-05	MDP FTS—4.1E-04 FTR—2.4E-04 TDP FTS—2.1E-02 FTR—8.2E-03	Plant-specific data were used except when not available. Bayesian update of generic; SAIC Generic Data Notebook for St. Lucie and Turkey Point was primary source of generic failure data. NPRDS primary source of component failure data. Operating hours estimated by review of operator logs and by understanding how system operated, tested, and maintained. Combined Unit 1 and 2 data since small number of failures and exposure time.

Table D-4. (continued).

Design Class	Reference Plant	IPE Generic (or Prior) Mean	IPE Estimate Used in Quantification	1987–1995 Experience	IPE Information Pertaining to Failure Data and Estimates
5 (2M, 1T, 3SG)	Farley 1	MDP FTS—3.0E-03 FTR—3.0E-05 TDP FTS—3.0E-02 FTR—6.4E-04	MDP FTS—1.5E-03 FTR—7.1E-05 TDP FTS—5.6E-03 FTR—7.3E-03	MDP FTS—4.2E-04 FTR—2.4E-04 TDP FTS—1.3E-02 FTR—8.2E-03	Bayesian update of generic; NUREG-4550 was primary source of failure data (not maintenance). FTR value for TDP was taken from an Advanced Light Water Reactor Design Document. IPE plant-specific MDP FTS 2 failures in 1,266 demands (1.6E-03); FTR 1 failure in 5,521 hours (1.8E-04). IPE plant-specific TDP FTS 3 failures in 616 demands (4.9E-03); FTR 1 failure in 858 hours (1.2E-03).
6 (3T, 3SG)	Turkey Point 3	TDP FTS—2.6E-02 FTR—8.9E-05	TDP FTS—5.5E-03 FTR—8.9E-05	TDP FTS—1.3E-02 FTR—8.2E-03	Plant-specific data were used except when not available. No Bayesian update of generic; SAIC Generic Data Notebook for St. Lucie and Turkey Point was primary source of generic failure data. Number of demands or operating hours, in general, not recorded in readily accessible databases. Operating hours estimated by review of operator logs and by understanding how system operated, tested, and maintained. Combined Unit 1 and 2 data.
7 (1M, 1D, 4SG)	Braidwood 1	MDP FTS—3.0E-03 FTR—1.0E-04 DDP FTS—2.6E-03 FTR—8E-04/d	MDP FTS—3.0E-03 FTR—1.0E-04 DDP FTS—2.6E-03 FTR—8E-04/d	MDP FTS—6.0E-04 FTR—2.4E-04 DDP FTS—5.7E-03 FTR—2.7E-02	Plant-specific data gathered for key components (pumps, MOVs) identified in past PRAs. Used data from both units. MDP and DDP significantly higher than generic maximum values due to limited operation so used generic values for the pumps. NUREG-2815 primary source of generic failure data. NUREG-4550 primary source of maintenance data. Also used IEEE-500. Byron used a similar process. IPE plant-specific MDP FTS 0 failures in 169 demands; FTR 4 failures in 180.1 hours (2.2E-02). Used NUREG-2815 mean failure rate for FTR(1E-04) IPE plant-specific DDP FTS 0 failures in 196 demands; FTR 1 failure in 100 hours (1.0E-02). Used NUREG-4550 mean failure rate for FTR(8E-4). The NUREG-4550 value is in units of per hour. However, the IPE used the value as a per demand, which is an error. The 1987–1995 experience estimate for a 24-hour mission is 0.47 (a factor of 587 difference between IPE and operational experience).

Table D-4. (continued).

Design Class	Reference Plant	IPE Generic (or Prior) Mean	IPE Estimate Used in Quantification	1987–1995 Experience	IPE Information Pertaining to Failure Data and Estimates
8 (1M, 1T, 4SG)	Seabrook	MDP FTS—3.3E-03 FTR—3.4E-05 TDP FTS—3.3E-02 FTR—1.0E-03	MDP FTS—3.3E-03 FTR—3.4E-05 TDP FTS—3.3E-02 FTR—1.0E-03	MDP FTS—5.5E-04 FTR—2.4E-04 TDP FTS—1.3E-02 FTR—8.2E-03	Failure distributions based on generic estimates and relevant data from operating plants (where available). PLG combined one stage Bayesian update. No plant-specific data included due to limited operation.
9 (2T, 4SG)	Haddam Neck	TDP FTS—3.1E-02 FTR—6.2E-04	TDP FTS—3.9E-03 FTR—3.0E-04	TDP FTS—1.3E-02 FTR—8.2E-03	Bayesian update of generic; Advanced Light Water Reactor Design Document was primary source of failure data. Additional generic sources included WASH-1400, IEEE-500, and Millstone Unit 3 PSS. Guidelines: 1. No failures observed assumed a 1/3 failure in the estimate; if this estimate was significantly greater or less than generic, the Bayesian updated value was used. If the 1/3 estimate was close to generic, the greater value was used. 2. When 2 failures observed, then: if the plant-specific estimate was significantly less than generic, the Bayesian update value was used; if significantly greater than generic, the plant-specific value used; if the plant-specific estimate was close to generic, the greater value was used. 3. When 3 or more failures observed, then plant-specific was used if supported by a trending study. IPE FTS is a Bayesian update, while the FTR is a plant-specific estimate.
10 (2M, 1T, 4SG)	Salem 1	MDP FTS—1.0E-03 FTR—1.0E-05 TDP FTS—5.0E-02 FTR—5.0E-05	MDP FTS—4.3E-04 FTR—1.0E-05 TDP FTS—3.6E-02 FTR—5.0E-05	MDP FTS—4.9E-04 FTR—2.4E-04 TDP FTS—1.4E-02 FTR—8.2E-03	Only collected plant-specific for AFW pumps FTS via NPRDS. Plant-specific failure rate information was used for what were considered to be potentially the most important events contributing to core damage. A single-stage Bayesian update of generic failure rates. However, used only generic for FTR. IPE plant-specific MDP FTS 0 failures in 431 demands. IPE plant-specific TDP FTS 5 failures in 140 demands (3.6E-02). Salem 2 followed the same process with the plant-specific information below: MDP FTS—3.3E-03 FTR—1.0E-05 Plant-specific MDP FTS 3 failures in 635 demands (4.7E-03). TDP FTS—6.5E-03 FTR—5.0E-05 Plant-specific turbine pump FTS 1 failure in 168 demands (6.0E-3).

Table D-4. (continued).

Design Class	Reference Plant	IPE Generic (or Prior) Mean	 Estimate Used in Quantification	1987–1995 Experience	IPE Information Pertaining to Failure Data and Estimates
11 (3M, 1T, 4SG)	South Texas 1	MDP FTS—3.3E-03 FTR—3.4E-05 TDP FTS—3.3E-02 FTR—1.0E-03	MDP FTS—3.3E-03 FTR—3.4E-05 TDP FTS—3.3E-02 FTR—1.0E-03	MDP FTS—2.8E-04 FTR—2.4E-04 TDP FTS—1.3E-02 FTR—8.2E-03	PSA developed prior to commercial operation. PLG generic data used in IPE since no plant-specific data available. Also used WASH-1400 and IEEE-500.

D-6. Additional Information Supporting the Unreliability Analysis

Information and results to support the auxiliary feedwater (AFW) system unreliability information provided in the main body of this report are presented. Figure D-3 provides the simple P&ID schematics used to define the piping segments for the 11 reference plants. The labeling of the segments correlate to the naming convention used in Figure 4 of the body of the report.

The plant-specific estimates of AFW operational unreliability and associated 90% uncertainty intervals calculated from the 1987–1995 experience are shown in Table D-5. Similar types of estimates, except for use in comparing with PRA/IPE results, are shown in Table D-6. The results presented in D-6 are calculated from the 1987–1995 experience. Table D-7 provides the AFW unreliability calculated for a PRA-based mission and the failure probability information cited in the PRA/IPEs.

Table D-8provides a list of AFW suction sources for each plant.

Table D-9 contains the importance measures (by design class) calculated for the various failure modes modeled in the fault tree depicting an operational mission. The importance measures are based on the Fussell-Vesely importance (fraction of the AFW unreliability that contain cut sets involving the event of interest). The importance measures for the overall industry are calculated by a weighted average of the Fussell-Vesely importances across the 11 design classes. The results provided in TableD-9 are based on the recovery probabilities identified in Table 4 of the body of the report. Table D-10 provides a sequential rank ordering (e.g., with 1 being highest importance and so on) of the information contained in Table D-9.

Table D-11 is a listing of the cut sets contributing 0.1% or greater to AFW unreliability for the operational mission for the reference plants representing the 11 AFW design classes.

Table D-12 contains the Fussell-Vesely importance measures of the AFW system failure modes (by AFW design class) for a PRA-based mission using the 1987–1995 experience data. The failure mode estimate is the unrecovered failure probability (that is, only failures that were not recovered or judged to be not recoverable). A weighted average of the importance measures across all design classes is provided in Table D-12. Table D-13 provides a sequential rank ordering of the information contained in Table D-12.

The listing of cut sets contributing 0.1% or greater to AFW unreliability for a PRA-based mission are tabulated in Table D-14.

Figure D-3. The simplified P&ID schematics of the reference plants representing the 11 AFW design configurations used in this study.

Figure D-3. (continued).

Figure D-3. (continued).

Figure D-3. (continued).

Figure D-3. (continued).

Figure D-3. (continued).

Figure D-3. (continued).

Figure D-3. (continued).

Figure D-3. (continued).

Figure D-3. (continued).

Figure D-3. (continued).

Table D-5. Plant-specific estimates of AFW operational unreliability and 90% uncertainty calculated from 1987–1995 experience.

AFW Design Class	Plant	5th Percentile of AFW Operational Unreliability	AFW Operational Unreliability Mean	95th Percentile of AFW Operational Unreliability
1	Arkansas Nuclear One 1	9.9E-06	4.9E-05	1.3E-04
1	Arkansas Nuclear One 2	1.1E-05	5.7E-05	1.6E-04
1	Crystal River 3	1.5E-05	1.5E-04	5.1E-04
1	Fort Calhoun	1.3E-05	7.7E-05	2.2E-04
1	Palo Verde 1	1.1E-05	5.4E-05	1.4E-04
1	Palo Verde 2	1.0E-05	5.1E-05	1.4E-04
1	Palo Verde 3	1.1E-05	5.3E-05	1.4E-04
1	Prairie Island 1	1.2E-05	5.9E-05	1.6E-04
1	Prairie Island 2	1.1E-05	5.5E-05	1.5E-04
2	Calvert Cliffs 1	3.5E-07	3.9E-06	1.3E-05
2	Calvert Cliffs 2	3.0E-07	3.5E-06	1.2E-05
3	Davis-Besse	1.4E-04	5.4E-04	1.3E-03
4	Ginna	7.1E-08	2.8E-06	1.1E-05
4	Kewaunee	2.1E-08	1.5E-06	6.5E-06
4	Millstone 2	5.5E-07	2.7E-05	1.3E-04
4	Oconee 1	9.0E-08	2.2E-05	1.2E-04
4	Oconee 2	2.0E-07	2.5E-05	1.2E-04
4	Oconee 3	1.1E-07	2.4E-05	1.3E-04
4	Palisades	4.0E-08	3.0E-06	1.2E-05
4	Point Beach 1	9.4E-08	3.3E-06	1.3E-05
4	Point Beach 2	8.4E-08	3.1E-06	1.2E-05
4	San Onofre 2	1.5E-07	6.0E-06	2.3E-05
4	San Onofre 3	1.4E-07	5.4E-06	2.0E-05
4	St. Lucie 1	6.0E-08	2.7E-06	1.1E-05
4	St. Lucie 2	6.0E-07	1.1E-05	4.2E-05
4	Three Mile Island 1	1.8E-07	2.7E-05	1.3E-04
4	Waterford 3	6.3E-08	4.9E-06	2.0E-05
5	Beaver Valley 1	4.0E-08	2.4E-06	1.0E-05
5	Beaver Valley 2	9.3E-08	5.2E-06	2.1E-05
5	Farley 1	5.4E-08	2.7E-06	1.0E-05
5	Farley 2	5.0E-08	2.5E-06	9.8E-06
5	H.B. Robinson	2.0E-07	4.3E-06	1.6E-05
5	Maine Yankee	4.2E-08	3.8E-06	1.5E-05
5	North Anna 1	9.0E-08	4.1E-06	1.5E-05
5	North Anna 2	9.1E-08	4.3E-06	1.6E-05
5	Shearon Harris 1	3.5E-08	2.2E-06	9.4E-06
5	Summer 1	4.3E-08	2.7E-06	1.1E-05
5	Surry 1	4.1E-08	2.5E-06	1.0E-05
5	Surry 2	3.7E-08	2.4E-06	9.7E-06
6	Turkey Point 3	1.2E-05	1.3E-04	4.2E-04
6	Turkey Point 4	1.5E-05	1.3E-04	4.3E-04

Table D-5. (continued).

AFW Design Class	Plant	5th Percentile of AFW Operational Unreliability	AFW Operational Unreliability Mean	95th Percentile of AFW Operational Unreliability
7	Braidwood 1	7.6E-07	1.8E-05	6.2E-05
7	Braidwood 2	7.5E-07	1.8E-05	6.0E-05
7	Byron 1	8.1E-07	1.8E-05	6.1E-05
7	Byron 2	8.0E-07	1.8E-05	5.9E-05
8	Seabrook	1.2E-05	5.3E-05	1.4E-04
9	Haddam Neck	1.7E-04	6.2E-04	1.4E-03
10	Callaway	6.9E-08	1.8E-06	7.4E-06
10	Catawba 1	5.2E-08	1.8E-06	7.3E-06
10	Catawba 2	5.2E-08	1.6E-06	6.6E-06
10	Comanche Peak 1	6.1E-08	1.7E-06	7.1E-06
10	Comanche Peak 2	9.1E-08	2.1E-06	8.3E-06
10	Cook 1	4.2E-07	3.8E-06	1.2E-05
10	Cook 2	7.9E-08	1.9E-06	7.8E-06
10	Diablo Canyon 1	2.7E-08	1.7E-06	7.2E-06
10	Diablo Canyon 2	2.9E-08	1.7E-06	7.4E-06
10	Indian Point 2	1.6E-07	3.4E-06	1.3E-05
10	Indian Point 3	3.1E-07	4.8E-06	1.7E-05
10	McGuire 1	7.0E-08	1.9E-06	7.6E-06
10	McGuire 2	6.7E-08	1.9E-06	7.4E-06
10	Millstone 3	3.4E-07	3.1E-06	1.1E-05
10	Salem 1	8.4E-08	2.0E-06	7.6E-06
10	Salem 2	7.7E-08	1.9E-06	7.6E-06
10	Sequoyah 1	2.6E-07	2.8E-06	1.0E-05
10	Sequoyah 2	4.7E-08	1.6E-06	6.6E-06
10	Vogtle 1	4.2E-08	1.6E-06	6.6E-06
10	Vogtle 2	6.7E-08	1.8E-06	7.4E-06
10	Wolf Creek	1.0E-06	6.6E-06	1.9E-05
10	Zion 1	3.1E-08	1.9E-06	8.3E-06
10	Zion 2	3.3E-08	1.9E-06	8.5E-06
11	South Texas 1	1.1E-06	4.5E-05	1.6E-04
11	South Texas 2	1.0E-08	8.1E-06	4.0E-05

Table D-6. Plant-specific estimates of AFW unreliability (PRA-based) and 90% uncertainty calculated from the 1987–1995 experience.

AFW Design Class	Plant	5th Percentile of AFW PRA-based Unreliability	AFW PRA-based Unreliability Mean	95th Percentile of AFW PRA-based Unreliability
1	Arkansas Nuclear One 1	3.6E-04	1.9E-03	5.1E-03
1	Arkansas Nuclear One 2	3.7E-04	1.9E-03	5.2E-03
1	Crystal River 3	4.9E-04	2.7E-03	7.5E-03
1	Fort Calhoun	3.9E-04	2.0E-03	5.2E-03
1	Palo Verde 1	3.6E-04	1.9E-03	5.3E-03
1	Palo Verde 2	3.6E-04	1.9E-03	5.2E-03
1	Palo Verde 3	3.6E-04	1.9E-03	5.2E-03
1	Prairie Island 1	3.7E-04	2.0E-03	5.3E-03
1	Prairie Island 2	3.7E-04	2.0E-03	5.2E-03
2	Calvert Cliffs 1	1.0E-04	6.6E-04	1.7E-03
2	Calvert Cliffs 2	1.0E-04	6.5E-04	1.7E-03
3	Davis-Besse	8.5E-03	3.9E-02	9.7E-02
4	Ginna	4.2E-05	7.8E-04	2.5E-03
4	Kewaunee	1.7E-05	3.7E-04	1.2E-03
4	Millstone 2	3.8E-05	4.3E-04	1.3E-03
4	Oconee 1	2.3E-05	3.9E-04	1.2E-03
4	Oconee 2	2.5E-05	3.9E-04	1.2E-03
4	Oconee 3	2.4E-05	4.0E-04	1.2E-03
4	Palisades	1.8E-05	3.7E-04	1.2E-03
4	Point Beach 1	2.0E-05	3.9E-04	1.2E-03
4	Point Beach 2	2.0E-05	3.8E-04	1.2E-03
4	San Onofre 2	2.3E-05	3.8E-04	1.2E-03
4	San Onofre 3	2.3E-05	3.8E-04	1.2E-03
4	St. Lucie 1	1.9E-05	3.7E-04	1.2E-03
4	St. Lucie 2	4.1E-05	4.2E-04	1.3E-03
4	Three Mile Island 1	2.4E-05	4.1E-04	1.2E-03
4	Waterford 3	1.7E-05	3.7E-04	1.2E-03
5	Beaver Valley 1	1.7E-05	3.6E-04	1.2E-03
5	Beaver Valley 2	1.8E-05	3.7E-04	1.2E-03
5	Farley 1	8.5E-06	3.4E-04	1.1E-03
5	Farley 2	8.3E-06	3.4E-04	1.1E-03
5	H.B. Robinson	2.9E-05	3.9E-04	1.2E-03
5	Maine Yankee	1.7E-05	3.7E-04	1.2E-03
5	North Anna 1	2.2E-05	3.8E-04	1.2E-03
5	North Anna 2	2.1E-05	3.8E-04	1.2E-03
5	Shearon Harris 1	1.7E-05	3.6E-04	1.2E-03
5	Summer 1	1.6E-05	3.7E-04	1.2E-03
5	Surry 1	1.5E-05	3.6E-04	1.2E-03
5	Surry 2	4.7E-05	1.0E-03	3.5E-03
6	Turkey Point 3	1.3E-03	7.3E-03	2.1E-02
6	Turkey Point 4	1.5E-03	8.2E-03	2.3E-02
7	Braidwood 1	3.7E-04	3.2E-03	1.0E-02
7	Braidwood 2	3.6E-04	3.1E-03	9.7E-03
7	Byron 1	3.5E-04	3.2E-03	1.0E-02

Table D-6. (continued).

AFW Design Class	Plant	5th Percentile of AFW PRA-based Unreliability	AFW PRA-based Unreliability Mean	95th Percentile of AFW PRA-based Unreliability
7	Byron 2	3.5E-04	3.1E-03	9.4E-03
8	Seabrook	1.5E-04	7.2E-04	1.8E-03
9	Haddam Neck	8.8E-03	3.9E-02	9.7E-02
10	Callaway	1.9E-05	3.6E-04	1.2E-03
10	Catawba 1	1.9E-05	3.7E-04	1.2E-03
10	Catawba 2	1.7E-05	3.6E-04	1.2E-03
10	Comanche Peak 1	1.8E-05	3.6E-04	1.2E-03
10	Comanche Peak 2	2.3E-05	3.9E-04	1.2E-03
10	Cook 1	4.3E-05	4.2E-04	1.3E-03
10	Cook 2	2.1E-05	3.7E-04	1.2E-03
10	Diablo Canyon 1	1.5E-05	3.6E-04	1.2E-03
10	Diablo Canyon 2	1.5E-05	3.6E-04	1.2E-03
10	Indian Point 2	2.7E-05	3.9E-04	1.2E-03
10	Indian Point 3	3.6E-05	4.1E-04	1.3E-03
10	McGuire 1	2.1E-05	3.7E-04	1.2E-03
10	McGuire 2	2.1E-05	3.7E-04	1.2E-03
10	Millstone 3	3.4E-05	3.9E-04	1.2E-03
10	Salem 1	2.1E-05	3.8E-04	1.2E-03
10	Salem 2	2.0E-05	3.7E-04	1.2E-03
10	Sequoyah 1	3.3E-05	3.9E-04	1.2E-03
10	Sequoyah 2	1.9E-05	3.7E-04	1.2E-03
10	Vogtle 1	7.8E-06	3.4E-04	1.1E-03
10	Vogtle 2	8.2E-06	3.4E-04	1.1E-03
10	Wolf Creek	6.8E-05	4.7E-04	1.3E-03
10	Zion 1	1.7E-05	3.7E-04	1.2E-03
10	Zion 2	1.7E-05	3.7E-04	1.2E-03
11	South Texas 1	2.7E-05	3.9E-04	1.2E-03
11	South Texas 2	1.1E-05	3.5E-04	1.2E-03

Table D-7. Plant-specific estimates of AFW unreliability (PRA-based)and 90% uncertainty based on the IPE failure rates.

AFW Design Class	Plant	5th Percentile of AFW IPE Unreliability	AFW IPE Unreliability Mean	95th Percentile of AFW IPE Unreliability
1	Arkansas Nuclear One 1	1.7E-05	5.1E-05	1.3E-04
1	Arkansas Nuclear One 2	1.4E-04	1.1E-03	3.4E-03
1	Crystal River 3	6.4E-05	1.5E-04	2.9E-04
1	Fort Calhoun	8.9E-05	3.6E-04	9.5E-04
1	Palo Verde 1	1.8E-04	7.7E-04	1.1E-03
1	Palo Verde 2	1.8E-04	7.7E-04	1.1E-03
1	Palo Verde 3	1.8E-04	7.7E-04	1.1E-03
1	Prairie Island 1		1.4E-03	
1	Prairie Island 2		1.4E-03	
2	Calvert Cliffs 1	1.1E-05	2.6E-05	5.2E-05
2	Calvert Cliffs 2	1.1E-05	2.6E-05	5.2E-05
3	Davis-Besse	1.7E-03	1.0E-02	2.7E-02
4	Ginna		1.7E-05	
4	Kewaunee	1.1E-04	3.6E-04	8.2E-04
4	Millstone 2		2.2E-04	
4	Oconee 1		1.1E-03	
4	Oconee 2		1.1E-03	
4	Oconee 3		1.1E-03	
4	Palisades		5.4E-05	
4	Point Beach 1		2.8E-05	
4	Point Beach 2		2.8E-05	
4	San Onofre 2	2.4E-05	6.4E-05	1.4E-04
4	San Onofre 3	2.4E-05	6.4E-05	1.4E-04
4	St. Lucie 1	1.3E-05	3.0E-05	6.1E-05
4	St. Lucie 2	1.3E-05	3.1E-05	6.3E-05
4	Three Mile Island 1	6.3E-07	2.4E-06	6.2E-06
4	Waterford 3	3.1E-06	3.2E-05	1.1E-04
5	Beaver Valley 1	6.9E-07	7.4E-06	2.6E-05
5	Beaver Valley 2	7.8E-07	1.1E-05	4.1E-05
5	Farley 1	1.1E-06	3.8E-06	8.8E-06
5	Farley 2	1.1E-06	3.8E-06	8.8E-06
5	H.B. Robinson	5.3E-05	2.0E-04	5.1E-04
5	Maine Yankee	8.5E-06	3.2E-05	7.6E-05
5	North Anna 1	1.8E-06	2.6E-05	9.1E-05
5	North Anna 2	1.8E-06	2.6E-05	9.1E-05
5	Shearon Harris 1	1.2E-04	3.6E-04	8.2E-04
5	Summer 1		8.5E-06	
5	Surry 1	3.4E-05	1.2E-04	3.6E-04
5	Surry 2	3.4E-05	1.2E-04	3.6E-04
6	Turkey Point 3	5.1E-05	2.4E-04	6.3E-04
6	Turkey Point 4	5.1E-05	2.4E-04	6.3E-04
7	Braidwood 1		4.1E-05	
7	Braidwood 2		4.1E-05	
7	Byron 1		1.0E-04	

Table D-7. (continued).

AFW Design Class	Plant	5th Percentile of AFW IPE Unreliability	AFW IPE Unreliability Mean	95th Percentile of AFW IPE Unreliability
7	Byron 2		1.0E-04	
8	Seabrook	3.6E-05	2.5E-04	7.8E-04
9	Haddam Neck		8.3E-04	
10	Callaway	1.5E-05	1.2E-04	3.9E-04
10	Catawba 1		4.2E-05	
10	Catawba 2		4.2E-05	
10	Comanche Peak 1		1.3E-05	
10	Comanche Peak 2		1.3E-05	
10	Cook 1	1.1E-06	5.9E-06	1.7E-05
10	Cook 2	1.1E-06	5.9E-06	1.7E-05
10	Diablo Canyon 1	1.1E-06	7.3E-06	2.2E-05
10	Diablo Canyon 2	1.1E-06	7.3E-06	2.2E-05
10	Indian Point 2	1.7E-05	8.6E-05	2.4E-04
10	Indian Point 3	6.8E-07	4.4E-06	1.3E-05
10	McGuire 1		4.3E-05	
10	McGuire 2		4.3E-05	
10	Millstone 3	1.5E-05	6.9E-05	1.9E-04
10	Salem 1	1.9E-06	1.4E-05	4.4E-05
10	Salem 2	6.7E-06	7.7E-05	2.6E-04
10	Sequoyah 1	8.9E-06	2.6E-05	5.8E-05
10	Sequoyah 2	8.9E-06	2.6E-05	5.8E-05
10	Vogtle 1	1.6E-06	7.6E-06	2.0E-05
10	Vogtle 2	1.6E-06	7.6E-06	2.0E-05
10	Wolf Creek	4.3E-06	1.7E-05	4.6E-05
10	Zion 1		1.2E-06	
10	Zion 2		1.2E-06	
11	South Texas 1	3.0E-06	1.2E-05	3.2E-05
11	South Texas 2	3.0E-06	1.2E-05	3.2E-05

Table D-8. A list of AFW suction sources compiled from plant information books.

AFW Design Class	Plant	AFW Suction Sources
1	Arkansas Nuclear One 1 & 2	***Automatic switch over to SW for ANO2 ;operator control for ANO1;*** ANO1 CSTs 321,000 gal and 202,000 gal; ANO2 CSTs 200,000 gal each; Crosstie to other units CST
1	Crystal River 3	Only CST @ 200,000 gal, hotwell @ 200,00 gal (locked closed), and Dedicated Emergency Feedwater Tank @ 184,000 gal
1	Fort Calhoun	Emergency Feedwater Tank @ 60,350 gal Firewater can fill tank along with Demin water, condensate sys. or CST; CST @ 150,000 gal that is hard piped to the non safety diesel driven AFW pump only
1	Palo Verde 1, 2, & 3	Manual valve alignment from Reactor Makeup Water Tank (420,000 gal); CST @ 550,000 gal
1	Prairie Island 1 & 2	MOV to Cooling Water Sys. (Mississippi River); CSTs 3@ 150,000 gal each shared by both units
2	Calvert Cliffs 1 & 2	CSTs 350,000 gal each; Crosstie to other units CSTs; MDAFW has a fire hose connection and can use Pretreated Water Storage Tank
3	Davis-Besse	MOVs to SW (preferred backup to CST); ***low suction pressure causes auto switch over to SW and inhibits steam to TD until switch over is completed***; CSTs 2@ 250,000 gal each
4	Ginna	MOV and manual valve that is closed; 2 CSTs @ 30,000 gal each makeup to these CSTs is from a 100,000 gal CST or the hotwell
4	Kewaunee	MOVs to SW; 2 CSTs @ 75,000 gal each
4	Millstone 2	Manual valves to Fire water; CST @ 250,000 gal; 2 Fire water tanks @ 245,00 gal each
4	Oconee 1, 2, & 3	Only CST (30,000 gal), USTs (2@ 36,000 gal each), and hotwell (142,000 gal)
4	Palisades	Locked closed manual valves to SW and Firewater; only one AFW pump (p-8c) can be served by SW. CST @ 125,000 gal, Pri., Coolant makeup Tank and Fire system
4	Point Beach 1 & 2	MOVs to SW and Firewater; low suction pressure and time delay trips AFW pump; CSTs (2 @ 45,000 gal each) shared by both units
4	San Onofre 2 & 3	Only CSTs (150,000gal); A 500,000 gal CST is hardpiped to other CSTs and not directly to pumps)

Table D-8. (continued).

AFW Design Class	Plant	AFW Suction Sources
4	St. Lucie 1 & 2	Only CSTs (Unit 1 @ 250,000 gal & Unit 2 @ 400,000 gal); Locked closed crosstie to units
4	Three Mile Island 1	MOVs to SW (river water) but need to reverse spectacle flange installed upstream of EFW pumps; CSTs (2 @ 265,000 gal each); hotwell @ 171,000gal
4	Waterford 3	Condensate Storage Pool @ 200,00 gal; Manual valves to backup source Wet Cooling Tower Basins (180,000 gal)
5	Beaver Valley 1 & 2	DWST @ 140,000 gal Manual valves to backup SW source (River Waterpumps)
5	Farley 1 & 2	MOVs to SW; CST @ 500,000 gal
5	Harris 1	MOVs to SW; manual switch over from control room; CST @ 415,000 gal
5	Maine Yankee	Demin. Water tank @ 150,000 gal; Manual valves to Pri. Water Storage Tank @ 150,000 gal
5	North Anna 1 & 2	Locked closed manual valves to SW and firewater; emergency CST @ 110,000 gal; CST @ 300,000 gal
5	Robinson	Locked closed manual valves to SW also L.C. valves to deep well pumps; CST @ 190,000 gal
5	Summer 1	MOVs to SW; CST @ 500,000 gal
5	Surry 1 & 2	Emerg. CST @ 110,000 gal; Manual valves to Fire main and Emergency M/U sys. (100,000 gal)
6	Turkey Point 3 & 4	Shared CSTs (2 @ 250,000 gal each) for both units; Limited supply from Demin. Water Tank (400 gpm) and Water treatment (200 gpm) Backup Service Water with a flexible hose during turbine operation with pump uncoupled
7	Braidwood 1 & 2	2 CSTs @ 500,000 gal each; ***Automatic switch over to Essential Service Water on low low pump suction pressure***
7	Byron 1 & 2	2 CSTs @ 500,000 gal each; ***Automatic switch over to Essential Service Water on low low pump suction pressure***
8	Seabrook	Only CST @ 400,000 gal
9	Haddem Neck	Only CST @100,000 gal
10	Callaway	***Low suction pressure switch over to SW***; CST @ 450,000 gal

Table D-8. (continued).

AFW Design Class	Plant	AFW Suction Sources
10	Catawba 1 & 2	***Low suction pressure switch over to SW***; CST @ 42,500 gal that is shared between both units. USTs (2 @ 42,500 gal each) hotwell @ 170,000 gal
10	Comanche Peak 1 & 2	MOVs can be aligned to SW; CST 500,000 gal
10	Cook 1 & 2	MOV and Locked closed manual valves to SW; CST @ 500,000 gal for each unit
10	Diablo Canyon 1 & 2	MOVs to Raw Water Reservoir (4.5 million gal); CST is 425,000 gal; Man. valves to fire water tank 300,000 gal
10	Indian Point 2	City Water Storage Tank (1.5 million gal) via AOVs (fail close) manual align; CST @ 600,000 gal
10	Indian Point 3	City Water Storage Tank (1.5 million gal) via AOVs (fail close) manual align; CST @ 600,000 gal
10	McGuire 1 & 2	***Low suction pressure switch over to SW (nuclear service waste)***; USTs 2@ 85,000 gal each; AFW CST @ 42,500 gal; hotwell @ 170,000 gal
10	Millstone 3	SW isolated from AFW by a blind flange; spool piece to connect systems; Demin. Water Storage Tank @ 360,000 gal; alternate source is CST @ 300,000 gal
10	Salem 1 & 2	AOVs to Backup service water and fire water however, requires installing spool piece; Aux feed storage tank @ 220,000 gal; Demin Water Storage Tank (2 @ 500,000 gal each)
10	Sequoyah 1 & 2	FCVs to Essential Raw Cooling Water; CSTs (2 @ 385,000 gal each)
10	Vogtle 1 & 2	Only CSTs (2 @ 480,000 gal each)
10	Wolf Creek	***Auto switch over via MOVs to SW (Wolf Creek Lake) on low suction pressure***; CST @ 450,000 gal
10	Zion 1 & 2	MOVs to SW; CST @ 500,000 gal
11	South Texas 1 & 2	Only AFW Storage Tank @ 525,000 gal

Table D-9. Fussell-Vesely importance measures of the AFW system failure modes (by AFW design class) used in the operational mission. The failure mode estimate is the unrecovered failure probability.

Failure Mode	Failure Probability[b]	Design Class Importance Measures[a] 1 (1M,1T,2SG)	2 (1M,2T,2SG)	3 (2T,2SG)	4 (2M,1T,2SG)	5 (2M,1T,3SG)	6 (3T,3SG)	7 (1M,1D,4SG)	8 (1M,1T,4SG)	9 (2T,4SG)	10 (2M,1T,4SG)	11 (3M,1T,4SG)	Overall Weighted Average[c]
MOOS-M	1.1E-03	1.5E-01	1.5E-01	—	1.7E-02	7.0E-03	—	3.5E-01	3.5E-01	—	3.9E-02	3.1E-05	8.1E-02
MOOS-T	4.6E-03	1.4E-01	2.5E-02	1.3E-01	1.7E-02	2.1E-02	7.5E-03	—	8.0E-02	1.2E-01	3.2E-02	2.0E-04	4.4E-02
FTS-ST	1.0E-03	4.4E-05	6.3E-04	4.0E-05	4.4E-06	4.6E-06	3.1E-06	—	4.4E-05	3.6E-02	7.0E-06	6.3E-05	1.1E-03
FTS-M	8.1E-04	7.2E-01	1.1E-01	—	1.1E-02	6.2E-03	—	1.9E-01	2.1E-01	—	2.6E-02	1.1E-05	1.3E-01
FTS-T	1.4E-02	6.6E-01	2.1E-01	5.1E-01	8.2E-02	7.5E-02	3.6E-02	—	5.3E-01	4.7E-01	1.6E-01	7.4E-04	2.1E-01
FTS-D	5.7E-03	—	—	—	—	—	—	7.1E-01	—	—	—	—	4.0E-02
FTR-M	5.7E-04	8.8E-02	9.8E-02	—	1.4E-02	8.4E-03	—	1.8E-01	2.1E-01	—	3.0E-02	2.3E-05	5.4E-02
FTR-T	3.6E-03	1.5E-01	4.7E-02	1.4E-01	2.3E-02	2.0E-02	1.1E-02	—	1.5E-01	1.3E-01	4.2E-02	2.2E-04	5.4E-02
FTO-INJ	2.4E-03	3.3E-04	1.7E-03	1.7E-04	3.7E-02	3.3E-02	2.2E-06	0.0	2.5E-02	2.2E-02	3.1E-02	4.0E-04	7.4E-02
PMPS-FTR	4.3E-04	3.5E-02	3.5E-01	9.6E-03	5.0E-01	4.9E-01	1.1E-02	2.8E-01	9.9E-02	8.4E-03	6.8E-01	1.8E-02	4.4E-01
MDPS-FTS	3.1E-03	—	—	—	4.4E-02	4.6E-02	—	—	—	—	7.5E-02	1.3E-03	4.1E-02
DIS-SEG	2.7E-03	6.7E-03	3.0E-01	2.6E-03	3.8E-01	3.9E-01	1.4E-02	7.6E-03	9.8E-02	2.4E-03	9.0E-02	9.8E-01	2.1E-01
TD-QT-STM	1.4E-03	5.0E-03	7.0E-02	2.1E-01	7.5E-04	6.5E-04	9.2E-01	—	4.9E-03	1.9E-01	1.3E-03	—	3.5E-02
ALPHA-FTR	See note d	3.5E-02	3.5E-01	9.6E-03	5.0E-01	4.9E-01	1.1E-02	2.8E-01	9.9E-02	8.4E-03	6.8E-01	1.8E-02	4.4E-01
ALPHA-FTS	See note d	—	—	—	4.4E-02	4.6E-02	—	—	—	—	7.5E-02	1.3E-03	4.1E-02
ALPHA-DISSEG	See note d	6.7E-03	3.0E-01	2.6E-03	3.8E-01	3.9E-01	1.4E-02	7.6E-03	9.8E-02	2.4E-03	9.0E-02	9.8E-01	2.1E-01
ALPHA-STM	See note d	5.0E-03	7.0E-02	2.1E-01	7.5E-04	6.5E-04	9.2E-01	—	4.9E-03	1.9E-01	1.3E-03	—	3.5E-02
Design class average unreliability[e]		6.7E-05	3.7E-06	5.4E-04	1.1E-05	3.3E-06	1.3E-04	1.8E-05	5.3E-05	6.2E-04	2.4E-06	2.6E-05	3.4E-05

a. The importance measures are Fussell-Vesely measures. The importance measures are for the plant that serves as the reference for the AFW design class. The design class (M,T,SG) defines the number of motor (M), turbine (T), diesel (D) pumps, and steam generators (SG).

b. The failure probability is the mean of the distribution. The estimates are taken from Table 4 of the main report and represent the arithmetic average of the industry as a whole.

c. The weighted average for a failure mode is the sum of the product of the population fraction and the failure mode importance for the design classes.

d. The common cause failure probabilities are dependent on the size of the common cause groups (e.g., common cause susceptibility of two pumps, three pumps, or four pumps). Specific Alpha factors are presented in Table 3 of the main report.

e. The AFW unreliability is the arithmetic average of the plants within an AFW design class.

Table D-10. Failure mode rankings, by Fussell-Vesely importance and AFW design class, of AFW unreliability for an operational mission.

		Design Class Importance Measures[a]											
Failure Mode	Failure Probability[b]	1 (1M,1T,2SG)	2 (1M,2T,2SG)	3 (2T,2SG)	4 (2M,1T,2SG)	5 (2M,1T,3SG)	6 (3T,3SG)	7 (1M,1D,4SG)	8 (1M,1T,4SG)	9 (2T,4SG)	10 (2M,1T,4SG)	11 (3M,1T,4SG)	Overall Weighted Average[c]
MOOS-M	1.1E-03	3	4	—	7	9	—	2	2	—	6	9	4
MOOS-T	4.6E-03	4	9	4	7	6	5	—	7	4	7	7	7
FTS-ST	1.0E-03	10	11	8	11	12	6	—	10	5	12	8	11
FTS-M	8.1E-04	1	5	—	9	10	—	4	3	—	10	11	3
FTS-T	1.4E-02	2	3	1	3	3	2	—	1	1	2	4	2
FTS-D	5.7E-03	—	—	—	—	—	—	1	—	—	—	—	9
FTR-M	5.7E-04	5	6	—	8	8	—	5	3	—	9	10	6
FTR-T	3.6E-03	3	8	3	6	7	4	—	4	3	5	6	6
FTO-INJ	2.4E-03	9	10	7	5	5	7	7	8	6	8	5	5
PMPS-FTR	4.3E-04	6	1	5	1	1	4	3	5	7	1	2	1
MDPS-FTS	3.1E-03	—	—	—	4	4	—	—	—	—	4	3	8
DIS-SEG	2.7E-03	7	2	6	2	2	3	6	6	8	3	1	2
TD-QT-STM	1.4E-03	8	7	2	10	11	1	—	9	2	11	—	10
ALPHA-FTR	See note d	6	1	5	1	1	4	3	5	7	1	2	1
ALPHA-FTS	See note d	—	—	—	4	4	—	—	—	—	4	3	8
ALPHA-DISSEG	See note d	7	2	6	2	2	3	6	6	8	3	1	2
ALPHA-STM	See note d	8	7	2	10	11	1	—	9	2	11	—	10
Design class average unreliability[e]		4	9	2	8	10	3	7	5	1	11	6	—

a. The importance measures are Fussell-Vesely measures. The importance measures are for the plant that serves as the reference for the AFW design class. The design class (M,T,SG) defines the number of motor (M), turbine (T), diesel (D) pumps, and steam generators (SG).

b. The failure probability is the mean of the distribution. The estimates are taken from Table 4of the main report and represent the arithmetic average of the industry as a whole.

c. The weighted average for a failure mode is the sum of the product of the population fraction and the failure mode importance for the design classes.

d. The common cause failure probabilities are dependent on the size of the common cause groups (e.g., common cause susceptibility of two pumps, three pumps, or four pumps). Specific Alpha factors are presented in Table 3 of the main report.

e. The AFW unreliability is the arithmetic average of the plants within an AFW design class.

Table D-11. A listing of the cut sets (by reference plant in the eleven AF W design classes) contributing 0.1% or greater to AFW operational unreliability (1987–1995 experience).

AFW design class 7
System: Braidwood
Mincut Upper Bound: 1.830E-005

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	34.9	6.4E-06	BRS1-EDP-FS	5.7E-03
			BRS1-MDP-MA	1.1E-03
2	28.2	5.1E-06	BRS1-ALPHA-FTR	1.2E-02
			BRS1-PMPS-FTR	4.3E-04
3	18.4	3.3E-06	BRS1-EDP-FS	5.7E-03
			BRS1-MDP-FS	6.0E-04
4	17.5	3.2E-06	BRS1-EDP-FS	5.7E-03
			BRS1-MDP-FR	5.7E-04
5	0.7	1.3E-07	BRS1-ALPHA-DISSG	2.4E-04
			BRS1-DIS-SEG	5.7E-04

AFW design class 2

System: Calvert Cliffs
Mincut Upper Bound: 3.786E-006

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	35.1	1.3E-06	CCN1-ALPHA-FTR	3.1E-03
			CCN1-PMPS-FTR	4.3E-04
2	29.5	1.1E-06	CCN1-ALPHA-DISSG	1.4E-03
			CCN1-DIS-SEG	8.3E-04
3	7.5	2.8E-07	CCN1-MDP-MA	1.1E-03
			CCN1-TDP11-FS	1.6E-02
			CCN1-TDP12-FS	1.6E-02
4	4.0	1.5E-07	CCN1-MDP-FS	6.1E-04
			CCN1-TDP11-FS	1.6E-02
			CCN1-TDP12-FS	1.6E-02
5	3.7	1.4E-07	CCN1-MDP-FR	5.7E-04
			CCN1-TDP11-FS	1.6E-02
			CCN1-TDP12-FS	1.6E-02
6	3.4	1.2E-07	CCN1-ALPHA-STM	8.5E-02
			CCN1-MDP-MA	1.1E-03
			CCN1-TD-QT-STM	1.4E-03
7	1.8	6.9E-08	CCN1-ALPHA-STM	8.5E-02
			CCN1-MDP-FS	6.1E-04
			CCN1-TD-QT-STM	1.4E-03
8	1.7	6.4E-08	CCN1-ALPHA-STM	8.5E-02
			CCN1-MDP-FR	5.7E-04
			CCN1-TD-QT-STM	1.4E-03

Table D-11. (continued).

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
9	1.6	6.4E-08	CCN1-MDP-MA	1.1E-03
			CCN1-TDP11-FR	3.6E-03
			CCN1-TDP12-FS	1.6E-02
10	1.6	6.4E-08	CCN1-MDP-MA	1.1E-03
			CCN1-TDP11-FS	1.6E-02
			CCN1-TDP12-FR	3.6E-03
11	1.0	3.9E-08	CCN1-MDP-FS	6.1E-04
			CCN1-TDP11-FS	1.6E-02
			CCN1-TDP12-MA	4.1E-03
12	1.0	3.9E-08	CCN1-MDP-FS	6.1E-04
			CCN1-TDP11-MA	4.1E-03
			CCN1-TDP12-FS	1.6E-02
13	0.9	3.6E-08	CCN1-MDP-FR	5.7E-04
			CCN1-TDP11-FS	1.6E-02
			CCN1-TDP12-MA	4.1E-03
14	0.9	3.6E-08	CCN1-MDP-FR	5.7E-04
			CCN1-TDP11-MA	4.1E-03
			CCN1-TDP12-FS	1.6E-02
15	0.9	3.4E-08	CCN1-MDP-FS	6.1E-04
			CCN1-TDP11-FR	3.6E-03
			CCN1-TDP12-FS	1.6E-02
16	0.9	3.4E-08	CCN1-MDP-FS	6.1E-04
			CCN1-TDP11-FS	1.6E-02
			CCN1-TDP12-FR	3.6E-03
17	0.8	3.2E-08	CCN1-MDP-FR	5.7E-04
			CCN1-TDP11-FR	3.6E-03
			CCN1-TDP12-FS	1.6E-02
18	0.8	3.2E-08	CCN1-MDP-FR	5.7E-04
			CCN1-TDP11-FS	1.6E-02
			CCN1-TDP12-FR	3.6E-03
19	0.3	1.4E-08	CCN1-MDP-MA	1.1E-03
			CCN1-TDP11-FR	3.6E-03
			CCN1-TDP12-FR	3.6E-03
20	0.2	8.8E-09	CCN1-MDP-FS	6.1E-04
			CCN1-TDP11-FR	3.6E-03
			CCN1-TDP12-MA	4.1E-03
21	0.2	8.8E-09	CCN1-MDP-FS	6.1E-04
			CCN1-TDP11-MA	4.1E-03
			CCN1-TDP12-FR	3.6E-03
22	0.2	8.2E-09	CCN1-MDP-FR	5.7E-04
			CCN1-TDP11-FR	3.6E-03
			CCN1-TDP12-MA	4.1E-03

Table D-11. (continued).

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
23	0.2	8.2E-09	CCN1-MDP-FR	5.7E-04
			CCN1-TDP11-MA	4.1E-03
			CCN1-TDP12-FR	3.6E-03
24	0.2	7.7E-09	CCN1-MDP-FS	6.1E-04
			CCN1-TDP11-FR	3.6E-03
			CCN1-TDP12-FR	3.6E-03
25	0.1	7.2E-09	CCN1-MDP-FR	5.7E-04
			CCN1-TDP11-FR	3.6E-03
			CCN1-TDP12-FR	3.6E-03

AFW design class 1

System: Crystal River 3
Mincut Upper Bound: 1.467E-004

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	48.7	7.1E-05	CRP3-MDP-FS	4.6E-03
			CRP3-TDP-FS	1.5E-02
2	11.9	1.7E-05	CRP3-MDP-FS	4.6E-03
			CRP3-TDP-MA	3.8E-03
3	11.8	1.7E-05	CRP3-MDP-MA	1.1E-03
			CRP3-TDP-FS	1.5E-02
4	11.2	1.6E-05	CRP3-MDP-FS	4.6E-03
			CRP3-TDP-FR	3.6E-03
5	5.9	8.7E-06	CRP3-MDP-FR	5.7E-04
			CRP3-TDP-FS	1.5E-02
6	3.5	5.1E-06	CRP3-ALPHA-FTR	1.2E-02
			CRP3-PMPS-FTR	4.3E-04
7	2.7	4.0E-06	CRP3-MDP-MA	1.1E-03
			CRP3-TDP-FR	3.6E-03
8	1.4	2.1E-06	CRP3-MDP-FR	5.7E-04
			CRP3-TDP-MA	3.8E-03
9	1.3	2.0E-06	CRP3-MDP-FR	5.7E-04
			CRP3-TDP-FR	3.6E-03
10	0.6	9.8E-07	CRP3-ALPHA-DISSG	1.4E-03
			CRP3-DIS-SEG	7.3E-04
11	0.3	5.3E-07	CRP3-ALPHA-STM	8.5E-02
			CRP3-MDP-FS	4.6E-03
			CRP3-TD-QT-STM	1.4E-03

Table D-11. (continued).

AFW design class 3

System: Davis-Besse
Mincut Upper Bound: 5.352E-004

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	31.7	1.7E-04	DBS1-TDP1-FS	1.3E-02
			DBS1-TDP2-FS	1.3E-02
2	21.4	1.1E-04	DBS1-ALPHA-STM	8.5E-02
			DBS1-TD-QT-STM	1.4E-03
3	10.1	5.4E-05	DBS1-TDP1-FS	1.3E-02
			DBS1-TDP2-MA	4.2E-03
4	10.1	5.4E-05	DBS1-TDP1-MA	4.2E-03
			DBS1-TDP2-FS	1.3E-02
5	8.6	4.6E-05	DBS1-TDP1-FR	3.6E-03
			DBS1-TDP2-FS	1.3E-02
6	8.6	4.6E-05	DBS1-TDP1-FS	1.3E-02
			DBS1-TDP2-FR	3.6E-03
7	2.7	1.4E-05	DBS1-TDP1-FR	3.6E-03
			DBS1-TDP2-MA	4.2E-03
8	2.7	1.4E-05	DBS1-TDP1-MA	4.2E-03
			DBS1-TDP2-FR	3.6E-03
9	2.3	1.2E-05	DBS1-TDP1-FR	3.6E-03
			DBS1-TDP2-FR	3.6E-03
10	0.9	5.1E-06	DBS1-ALPHA-FTR	1.2E-02
			DBS1-PMPS-FTR	4.3E-04
11	0.2	1.4E-06	DBS1-ALPHA-DISSG	1.4E-03
			DBS1-DIS-SEG	1.0E-03

AFW design class 9

System: Haddem Neck
Mincut Upper Bound: 6.165E-004

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	28.2	1.7E-04	HNP1-TDPA-FS	1.3E-02
			HNP1-TDPB-FS	1.3E-02
2	18.5	1.1E-04	HNP1-ALPHA-STM	8.5E-02
			HNP1-TD-QT-STM	1.4E-03
3	9.1	5.6E-05	HNP1-TDPA-FS	1.3E-02
			HNP1-TDPB-MA	4.3E-03
4	9.1	5.6E-05	HNP1-TDPA-MA	4.3E-03
			HNP1-TDPB-FS	1.3E-02

Table D-11. (continued).

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
5	7.6	4.7E-05	HNP1-TDPA-FR	3.6E-03
			HNP1-TDPB-FS	1.3E-02
6	7.6	4.7E-05	HNP1-TDPA-FS	1.3E-02
			HNP1-TDPB-FR	3.6E-03
7	2.4	1.5E-05	HNP1-TDPA-FR	3.6E-03
			HNP1-TDPB-MA	4.3E-03
8	2.4	1.5E-05	HNP1-TDPA-MA	4.3E-03
			HNP1-TDPB-FR	3.6E-03
9	2.1	1.3E-05	HNP1-TDA-STM-SUP	1.0E-03
			HNP1-TDPB-FS	1.3E-02
10	2.1	1.3E-05	HNP1-TDB-STM-SUP	1.0E-03
			HNP1-TDPA-FS	1.3E-02
11	2.0	1.2E-05	HNP1-TDPA-FR	3.6E-03
			HNP1-TDPB-FR	3.6E-03
12	0.8	5.1E-06	HNP1-ALPHA-FTR	1.2E-02
			HNP1-PMPS-FTR	4.3E-04
13	0.7	4.6E-06	HNP1-PMP-SG1-SEG	2.1E-03
			HNP1-PMP-SG2-SEG	2.1E-03
14	0.7	4.6E-06	HNP1-PMP-SG1-SEG	2.1E-03
			HNP1-PMP-SG3-SEG	2.1E-03
15	0.7	4.6E-06	HNP1-PMP-SG1-SEG	2.1E-03
			HNP1-PMP-SG4-SEG	2.1E-03
16	0.7	4.6E-06	HNP1-PMP-SG2-SEG	2.1E-03
			HNP1-PMP-SG3-SEG	2.1E-03
17	0.7	4.6E-06	HNP1-PMP-SG2-SEG	2.1E-03
			HNP1-PMP-SG4-SEG	2.1E-03
18	0.7	4.6E-06	HNP1-PMP-SG3-SEG	2.1E-03
			HNP1-PMP-SG4-SEG	2.1E-03
19	0.7	4.3E-06	HNP1-TDA-STM-SUP	1.0E-03
			HNP1-TDPB-MA	4.3E-03
20	0.7	4.3E-06	HNP1-TDB-STM-SUP	1.0E-03
			HNP1-TDPA-MA	4.3E-03
21	0.5	3.6E-06	HNP1-TDA-STM-SUP	1.0E-03
			HNP1-TDPB-FR	3.6E-03
22	0.5	3.6E-06	HNP1-TDB-STM-SUP	1.0E-03
			HNP1-TDPA-FR	3.6E-03
23	0.2	1.4E-06	HNP1-ALPHA-DISSG	1.4E-03
			HNP1-DIS-SEG	1.1E-03
24	0.1	1.0E-06	HNP1-TDA-STM-SUP	1.0E-03
			HNP1-TDB-STM-SUP	1.0E-03

Table D-11. (continued).

AFW design class 5

System: Joseph M Farley
Mincut Upper Bound: 2.694E-006

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	49.4	1.3E-06	JMF1-ALPHA-FTR	3.1E-03
			JMF1-PMPS-FTR	4.3E-04
2	38.9	1.0E-06	JMF1-ALPHA-DISSG	1.5E-03
			JMF1-DIS-SEG	7.2E-04
3	2.8	7.7E-08	JMF1-ALPHA-MDFTS	2.8E-02
			JMF1-MDPS-FTS	2.1E-04
			JMF1-TDP-FS	1.3E-02
4	1.0	2.7E-08	JMF1-MDS-SGA-SEG	1.4E-03
			JMF1-MDS-SGB-SEG	1.4E-03
			JMF1-TDP-FS	1.3E-02
5	1.0	2.7E-08	JMF1-MDS-SGA-SEG	1.4E-03
			JMF1-MDS-SGC-SEG	1.4E-03
			JMF1-TDP-FS	1.3E-02
6	1.0	2.7E-08	JMF1-MDS-SGB-SEG	1.4E-03
			JMF1-MDS-SGC-SEG	1.4E-03
			JMF1-TDP-FS	1.3E-02
7	0.9	2.5E-08	JMF1-ALPHA-MDFTS	2.8E-02
			JMF1-MDPS-FTS	2.1E-04
			JMF1-TDP-MA	4.3E-03
8	0.7	2.0E-08	JMF1-ALPHA-MDFTS	2.8E-02
			JMF1-MDPS-FTS	2.1E-04
			JMF1-TDP-FR	3.6E-03
9	0.3	8.9E-09	JMF1-MDS-SGA-SEG	1.4E-03
			JMF1-MDS-SGB-SEG	1.4E-03
			JMF1-TDP-MA	4.3E-03
10	0.3	8.9E-09	JMF1-MDS-SGA-SEG	1.4E-03
			JMF1-MDS-SGC-SEG	1.4E-03
			JMF1-TDP-MA	4.3E-03
11	0.3	8.9E-09	JMF1-MDS-SGB-SEG	1.4E-03
			JMF1-MDS-SGC-SEG	1.4E-03
			JMF1-TDP-MA	4.3E-03
12	0.3	8.4E-09	JMF1-MDPA-FR	5.7E-04
			JMF1-MDPB-MA	1.1E-03
			JMF1-TDP-FS	1.3E-02
13	0.3	8.4E-09	JMF1-MDPA-MA	1.1E-03
			JMF1-MDPB-FR	5.7E-04
			JMF1-TDP-FS	1.3E-02

Table D-11. (continued).

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
14	0.2	7.3E-09	JMF1-MDS-SGA-SEG	1.4E-03
			JMF1-MDS-SGB-SEG	1.4E-03
			JMF1-TDP-FR	3.6E-03
15	0.2	7.3E-09	JMF1-MDS-SGA-SEG	1.4E-03
			JMF1-MDS-SGC-SEG	1.4E-03
			JMF1-TDP-FR	3.6E-03
16	0.2	7.3E-09	JMF1-MDS-SGB-SEG	1.4E-03
			JMF1-MDS-SGC-SEG	1.4E-03
			JMF1-TDP-FR	3.6E-03
17	0.2	6.2E-09	JMF1-MDPA-FS	4.2E-04
			JMF1-MDPB-MA	1.1E-03
			JMF1-TDP-FS	1.3E-02
18	0.2	6.2E-09	JMF1-MDPA-MA	1.1E-03
			JMF1-MDPB-FS	4.2E-04
			JMF1-TDP-FS	1.3E-02
19	0.1	4.2E-09	JMF1-MDPA-FR	5.7E-04
			JMF1-MDPB-FR	5.7E-04
			JMF1-TDP-FS	1.3E-02
20	0.1	3.1E-09	JMF1-MDPA-FR	5.7E-04
			JMF1-MDPB-FS	4.2E-04
			JMF1-TDP-FS	1.3E-02
21	0.1	3.1E-09	JMF1-MDPA-FS	4.2E-04
			JMF1-MDPB-FR	5.7E-04
			JMF1-TDP-FS	1.3E-02

AFW design class 8

System: Seabrook
Mincut Upper Bound: 5.221E-005

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	26.6	1.3E-05	SBK1-MDP-MA	1.1E-03
			SBK1-TDP-FS	1.2E-02
2	13.4	6.9E-06	SBK1-MDP-FR	5.7E-04
			SBK1-TDP-FS	1.2E-02
3	13.0	6.8E-06	SBK1-MDP-FS	5.5E-04
			SBK1-TDP-FS	1.2E-02
4	9.8	5.1E-06	SBK1-ALPHA-FTR	1.2E-02
			SBK1-PMPS-FTR	4.3E-04
5	9.8	5.1E-06	SBK1-ALPHA-DISSG	1.4E-03
			SBK1-DIS-SEG	3.8E-03
6	7.7	4.0E-06	SBK1-MDP-MA	1.1E-03
			SBK1-TDP-FR	3.6E-03

Table D-11. (continued).

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
7	4.0	2.1E-06	SBK1-MDP-FR	5.7E-04
			SBK1-TDP-MA	3.7E-03
8	3.9	2.0E-06	SBK1-MDP-FS	5.5E-04
			SBK1-TDP-MA	3.7E-03
9	3.8	2.0E-06	SBK1-MDP-FR	5.7E-04
			SBK1-TDP-FR	3.6E-03
10	3.7	1.9E-06	SBK1-MDP-FS	5.5E-04
			SBK1-TDP-FR	3.6E-03
11	0.8	4.3E-07	SBK1-MDTD-SGA-SG	7.6E-03
			SBK1-MDTD-SGB-SG	7.6E-03
			SBK1-MDTD-SGC-SG	7.6E-03
12	0.8	4.3E-07	SBK1-MDTD-SGA-SG	7.6E-03
			SBK1-MDTD-SGB-SG	7.6E-03
			SBK1-MDTD-SGD-SG	7.6E-03
13	0.8	4.3E-07	SBK1-MDTD-SGA-SG	7.6E-03
			SBK1-MDTD-SGC-SG	7.6E-03
			SBK1-MDTD-SGD-SG	7.6E-03
14	0.8	4.3E-07	SBK1-MDTD-SGB-SG	7.6E-03
			SBK1-MDTD-SGC-SG	7.6E-03
			SBK1-MDTD-SGD-SG	7.6E-03
15	0.2	1.2E-07	SBK1-ALPHA-STM	8.5E-02
			SBK1-MDP-MA	1.1E-03
			SBK1-TD-QT-STM	1.4E-03
16	0.1	6.4E-08	SBK1-ALPHA-STM	8.5E-02
			SBK1-MDP-FR	5.7E-04
			SBK1-TD-QT-STM	1.4E-03
17	0.1	6.3E-08	SBK1-ALPHA-STM	8.5E-02
			SBK1-MDP-FS	5.5E-04
			SBK1-TD-QT-STM	1.4E-03

AFW design class 10

System: Salem
Mincut Upper Bound: 1.961E-006

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	67.9	1.3E-06	SGS1-ALPHA-FTR	3.1E-03
			SGS1-PMPS-FTR	4.3E-04
2	9.0	1.7E-07	SGS1-ALPHA-DISSG	2.4E-04
			SGS1-DIS-SEG	7.3E-04
3	4.6	9.1E-08	SGS1-ALPHA-MDFTS	2.8E-02
			SGS1-MDPS-FTS	2.4E-04
			SGS1-TDP-FS	1.3E-02

Table D-11. (continued).

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
4	1.5	3.0E-08	SGS1-ALPHA-MDFTS	2.8E-02
			SGS1-MDPS-FTS	2.4E-04
			SGS1-TDP-MA	4.4E-03
5	1.2	2.4E-08	SGS1-ALPHA-MDFTS	2.8E-02
			SGS1-MDPS-FTS	2.4E-04
			SGS1-TDP-FR	3.6E-03
6	1.1	2.1E-08	SGS1-MD1-SG3-SEG	1.5E-03
			SGS1-MDP12-MA	1.1E-03
			SGS1-TDP-FS	1.3E-02
7	1.1	2.1E-08	SGS1-MD1-SG4-SEG	1.5E-03
			SGS1-MDP12-MA	1.1E-03
			SGS1-TDP-FS	1.3E-02
8	1.1	2.1E-08	SGS1-MD2-SG1-SEG	1.5E-03
			SGS1-MDP11-MA	1.1E-03
			SGS1-TDP-FS	1.3E-02
9	1.1	2.1E-08	SGS1-MD2-SG2-SEG	1.5E-03
			SGS1-MDP11-MA	1.1E-03
			SGS1-TDP-FS	1.3E-02
10	0.5	1.1E-08	SGS1-MD1-SG3-SEG	1.5E-03
			SGS1-MDP12-FR	5.7E-04
			SGS1-TDP-FS	1.3E-02
11	0.5	1.1E-08	SGS1-MD1-SG4-SEG	1.5E-03
			SGS1-MDP12-FR	5.7E-04
			SGS1-TDP-FS	1.3E-02
12	0.5	1.1E-08	SGS1-MD2-SG1-SEG	1.5E-03
			SGS1-MDP11-FR	5.7E-04
			SGS1-TDP-FS	1.3E-02
13	0.5	1.1E-08	SGS1-MD2-SG2-SEG	1.5E-03
			SGS1-MDP11-FR	5.7E-04
			SGS1-TDP-FS	1.3E-02
14	0.4	9.4E-09	SGS1-MD1-SG3-SEG	1.5E-03
			SGS1-MDP12-FS	4.9E-04
			SGS1-TDP-FS	1.3E-02
15	0.4	9.4E-09	SGS1-MD1-SG4-SEG	1.5E-03
			SGS1-MDP12-FS	4.9E-04
			SGS1-TDP-FS	1.3E-02
16	0.4	9.4E-09	SGS1-MD2-SG1-SEG	1.5E-03
			SGS1-MDP11-FS	4.9E-04
			SGS1-TDP-FS	1.3E-02
17	0.4	9.4E-09	SGS1-MD2-SG2-SEG	1.5E-03
			SGS1-MDP11-FS	4.9E-04
			SGS1-TDP-FS	1.3E-02
18	0.4	8.5E-09	SGS1-MDP11-FR	5.7E-04
			SGS1-MDP12-MA	1.1E-03
			SGS1-TDP-FS	1.3E-02

Table D-11. (continued).

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
19	0.4	8.5E-09	SGS1-MDP11-MA	1.1E-03
			SGS1-MDP12-FR	5.7E-04
			SGS1-TDP-FS	1.3E-02
20	0.3	7.3E-09	SGS1-MDP11-FS	4.9E-04
			SGS1-MDP12-MA	1.1E-03
			SGS1-TDP-FS	1.3E-02
21	0.3	7.3E-09	SGS1-MDP11-MA	1.1E-03
			SGS1-MDP12-FS	4.9E-04
			SGS1-TDP-FS	1.3E-02
22	0.3	5.8E-09	SGS1-MD1-SG3-SEG	1.5E-03
			SGS1-MDP12-MA	1.1E-03
			SGS1-TDP-FR	3.6E-03
23	0.3	5.8E-09	SGS1-MD1-SG4-SEG	1.5E-03
			SGS1-MDP12-MA	1.1E-03
			SGS1-TDP-FR	3.6E-03
24	0.3	5.8E-09	SGS1-MD2-SG1-SEG	1.5E-03
			SGS1-MDP11-MA	1.1E-03
			SGS1-TDP-FR	3.6E-03
25	0.3	5.8E-09	SGS1-MD2-SG2-SEG	1.5E-03
			SGS1-MDP11-MA	1.1E-03
			SGS1-TDP-FR	3.6E-03
26	0.2	4.2E-09	SGS1-MDP11-FR	5.7E-04
			SGS1-MDP12-FR	5.7E-04
			SGS1-TDP-FS	1.3E-02
27	0.1	3.6E-09	SGS1-MDP11-FR	5.7E-04
			SGS1-MDP12-FS	4.9E-04
			SGS1-TDP-FS	1.3E-02
28	0.1	3.6E-09	SGS1-MDP11-FS	4.9E-04
			SGS1-MDP12-FR	5.7E-04
			SGS1-TDP-FS	1.3E-02
29	0.1	3.6E-09	SGS1-MD1-SG3-SEG	1.5E-03
			SGS1-MDP12-FR	5.7E-04
			SGS1-TDP-MA	4.4E-03
30	0.1	3.6E-09	SGS1-MD1-SG4-SEG	1.5E-03
			SGS1-MDP12-FR	5.7E-04
			SGS1-TDP-MA	4.4E-03
31	0.1	3.6E-09	SGS1-MD2-SG1-SEG	1.5E-03
			SGS1-MDP11-FR	5.7E-04
			SGS1-TDP-MA	4.4E-03
32	0.1	3.6E-09	SGS1-MD2-SG2-SEG	1.5E-03
			SGS1-MDP11-FR	5.7E-04
			SGS1-TDP-MA	4.4E-03
33	0.1	3.1E-09	SGS1-MDP11-FS	4.9E-04
			SGS1-MDP12-FS	4.9E-04
			SGS1-TDP-FS	1.3E-02

Table D-11. (continued).

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
34	0.1	3.1E-09	SGS1-MD1-SG3-SEG	1.5E-03
			SGS1-MDP12-FS	4.9E-04
			SGS1-TDP-MA	4.4E-03
35	0.1	3.1E-09	SGS1-MD1-SG4-SEG	1.5E-03
			SGS1-MDP12-FS	4.9E-04
			SGS1-TDP-MA	4.4E-03
36	0.1	3.1E-09	SGS1-MD2-SG1-SEG	1.5E-03
			SGS1-MDP11-FS	4.9E-04
			SGS1-TDP-MA	4.4E-03
37	0.1	3.1E-09	SGS1-MD2-SG2-SEG	1.5E-03
			SGS1-MDP11-FS	4.9E-04
			SGS1-TDP-MA	4.4E-03
38	0.1	2.9E-09	SGS1-MD1-SG3-SEG	1.5E-03
			SGS1-MDP12-FR	5.7E-04
			SGS1-TDP-FR	3.6E-03
39	0.1	2.9E-09	SGS1-MD1-SG4-SEG	1.5E-03
			SGS1-MDP12-FR	5.7E-04
			SGS1-TDP-FR	3.6E-03
40	0.1	2.9E-09	SGS1-MD2-SG1-SEG	1.5E-03
			SGS1-MDP11-FR	5.7E-04
			SGS1-TDP-FR	3.6E-03
41	0.1	2.9E-09	SGS1-MD2-SG2-SEG	1.5E-03
			SGS1-MDP11-FR	5.7E-04
			SGS1-TDP-FR	3.6E-03
42	0.1	2.5E-09	SGS1-MD1-SG3-SEG	1.5E-03
			SGS1-MDP12-FS	4.9E-04
			SGS1-TDP-FR	3.6E-03
43	0.1	2.5E-09	SGS1-MD1-SG4-SEG	1.5E-03
			SGS1-MDP12-FS	4.9E-04
			SGS1-TDP-FR	3.6E-03
44	0.1	2.5E-09	SGS1-MD2-SG1-SEG	1.5E-03
			SGS1-MDP11-FS	4.9E-04
			SGS1-TDP-FR	3.6E-03
45	0.1	2.5E-09	SGS1-MD2-SG2-SEG	1.5E-03
			SGS1-MDP11-FS	4.9E-04
			SGS1-TDP-FR	3.6E-03
46	0.1	2.2E-09	SGS1-MDP11-FR	5.7E-04
			SGS1-MDP12-MA	1.1E-03
			SGS1-TDP-FR	3.6E-03
47	0.1	2.2E-09	SGS1-MDP11-MA	1.1E-03
			SGS1-MDP12-FR	5.7E-04
			SGS1-TDP-FR	3.6E-03
48	0.1	1.9E-09	SGS1-MDP11-FS	4.9E-04
			SGS1-MDP12-MA	1.1E-03
			SGS1-TDP-FR	3.6E-03

Table D-11. (continued).

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
49	0.1	1.9E-09	SGS1-MDP11-MA	1.1E-03
			SGS1-MDP12-FS	4.9E-04
			SGS1-TDP-FR	3.6E-03

AFW design class 4

System: St. Lucie
Mincut Upper Bound: 2.650E-006

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	50.2	1.3E-06	SLS1-ALPHA-FTR	3.1E-03
			SLS1-PMPS-FTR	4.3E-04
2	37.4	9.9E-07	SLS1-ALPHA-DISSG	1.4E-03
			SLS1-DIS-SEG	7.4E-04
3	2.7	7.2E-08	SLS1-ALPHA-MDFTS	2.8E-02
			SLS1-MDPS-FTS	2.1E-04
			SLS1-TDP-FS	1.3E-02
4	1.0	2.7E-08	SLS1-MDA-SGA-SEG	1.5E-03
			SLS1-MDB-SGB-SEG	1.5E-03
			SLS1-TDP-FS	1.3E-02
5	0.8	2.2E-08	SLS1-ALPHA-MDFTS	2.8E-02
			SLS1-MDPS-FTS	2.1E-04
			SLS1-TDP-MA	3.8E-03
6	0.7	2.0E-08	SLS1-MDA-SGA-SEG	1.5E-03
			SLS1-MDPB-MA	1.1E-03
			SLS1-TDP-FS	1.3E-02
7	0.7	2.0E-08	SLS1-MDB-SGB-SEG	1.5E-03
			SLS1-MDPA-MA	1.1E-03
			SLS1-TDP-FS	1.3E-02
8	0.7	2.0E-08	SLS1-ALPHA-MDFTS	2.8E-02
			SLS1-MDPS-FTS	2.1E-04
			SLS1-TDP-FR	3.6E-03
9	0.3	1.0E-08	SLS1-MDA-SGA-SEG	1.5E-03
			SLS1-MDPB-FR	5.7E-04
			SLS1-TDP-FS	1.3E-02
10	0.3	1.0E-08	SLS1-MDB-SGB-SEG	1.5E-03
			SLS1-MDPA-FR	5.7E-04
			SLS1-TDP-FS	1.3E-02
11	0.3	8.3E-09	SLS1-MDA-SGA-SEG	1.5E-03
			SLS1-MDB-SGB-SEG	1.5E-03
			SLS1-TDP-MA	3.8E-03

Table D-11. (continued).

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
12	0.3	7.9E-09	SLS1-MDPA-FR	5.7E-04
			SLS1-MDPB-MA	1.1E-03
			SLS1-TDP-FS	1.3E-02
13	0.3	7.9E-09	SLS1-MDPA-MA	1.1E-03
			SLS1-MDPB-FR	5.7E-04
			SLS1-TDP-FS	1.3E-02
14	0.2	7.7E-09	SLS1-MDA-SGA-SEG	1.5E-03
			SLS1-MDB-SGB-SEG	1.5E-03
			SLS1-TDP-FR	3.6E-03
15	0.2	7.5E-09	SLS1-MDA-SGA-SEG	1.5E-03
			SLS1-MDPB-FS	4.1E-04
			SLS1-TDP-FS	1.3E-02
16	0.2	7.5E-09	SLS1-MDB-SGB-SEG	1.5E-03
			SLS1-MDPA-FS	4.1E-04
			SLS1-TDP-FS	1.3E-02
17	0.2	5.9E-09	SLS1-MDA-SGA-SEG	1.5E-03
			SLS1-MDPB-MA	1.1E-03
			SLS1-TDP-FR	3.6E-03
18	0.2	5.9E-09	SLS1-MDB-SGB-SEG	1.5E-03
			SLS1-MDPA-MA	1.1E-03
			SLS1-TDP-FR	3.6E-03
19	0.2	5.8E-09	SLS1-MDPA-FS	4.1E-04
			SLS1-MDPB-MA	1.1E-03
			SLS1-TDP-FS	1.3E-02
20	0.2	5.8E-09	SLS1-MDPA-MA	1.1E-03
			SLS1-MDPB-FS	4.1E-04
			SLS1-TDP-FS	1.3E-02
21	0.1	4.0E-09	SLS1-MDPA-FR	5.7E-04
			SLS1-MDPB-FR	5.7E-04
			SLS1-TDP-FS	1.3E-02
22	0.1	3.1E-09	SLS1-MDA-SGA-SEG	1.5E-03
			SLS1-MDPB-FR	5.7E-04
			SLS1-TDP-MA	3.8E-03
23	0.1	3.1E-09	SLS1-MDB-SGB-SEG	1.5E-03
			SLS1-MDPA-FR	5.7E-04
			SLS1-TDP-MA	3.8E-03
24	0.1	2.9E-09	SLS1-MDA-SGA-SEG	1.5E-03
			SLS1-MDPB-FR	5.7E-04
			SLS1-TDP-FR	3.6E-03
25	0.1	2.9E-09	SLS1-MDB-SGB-SEG	1.5E-03
			SLS1-MDPA-FR	5.7E-04
			SLS1-TDP-FR	3.6E-03

Table D-11. (continued).

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
26	0.1	2.9E-09	SLS1-MDPA-FR	5.7E-04
			SLS1-MDPB-FS	4.1E-04
			SLS1-TDP-FS	1.3E-02
27	0.1	2.9E-09	SLS1-MDPA-FS	4.1E-04
			SLS1-MDPB-FR	5.7E-04
			SLS1-TDP-FS	1.3E-02

AFW design class 11

System: South Texas Project
Mincut Upper Bound: 4.474E-005

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	98.0	4.3E-05	STN1-ALPHA-DISSG	1.4E-02
			STN1-DIS-SEG	3.3E-03
2	1.7	7.9E-07	STN1-ALPHA-FTR	1.9E-03
			STN1-PMPS-FTR	4.3E-04

AFW design class 6
System: Turkey Point
Mincut Upper Bound: 1.244E-004

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	92.1	1.1E-04	TPS3-ALPHA-STM	8.5E-02
			TPS3-TD-QT-STM	1.4E-03
2	1.4	1.8E-06	TPS3-TDP1-FS	1.2E-02
			TPS3-TDP2-FS	1.2E-02
			TPS3-TDP3-FS	1.2E-02
3	1.4	1.7E-06	TPS3-ALPHA-DISSG	1.5E-03
			TPS3-DIS-SEG	1.2E-03
4	1.0	1.3E-06	TPS3-ALPHA-FTR	3.1E-03
			TPS3-PMPS-FTR	4.3E-04
5	0.4	5.5E-07	TPS3-TDP1-FS	1.2E-02
			TPS3-TDP2-FS	1.2E-02
			TPS3-TDP3-MA	3.7E-03
6	0.4	5.5E-07	TPS3-TDP1-FS	1.2E-02
			TPS3-TDP2-MA	3.7E-03
			TPS3-TDP3-FS	1.2E-02

Table D-11. (continued).

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
7	0.4	5.5E-07	TPS3-TDP1-MA	3.7E-03
			TPS3-TDP2-FS	1.2E-02
			TPS3-TDP3-FS	1.2E-02
8	0.4	5.3E-07	TPS3-TDP1-FR	3.6E-03
			TPS3-TDP2-FS	1.2E-02
			TPS3-TDP3-FS	1.2E-02
9	0.4	5.3E-07	TPS3-TDP1-FS	1.2E-02
			TPS3-TDP2-FR	3.6E-03
			TPS3-TDP3-FS	1.2E-02
10	0.4	5.3E-07	TPS3-TDP1-FS	1.2E-02
			TPS3-TDP2-FS	1.2E-02
			TPS3-TDP3-FR	3.6E-03
11	0.1	1.6E-07	TPS3-TDP1-FR	3.6E-03
			TPS3-TDP2-FS	1.2E-02
			TPS3-TDP3-MA	3.7E-03
12	0.1	1.6E-07	TPS3-TDP1-FR	3.6E-03
			TPS3-TDP2-MA	3.7E-03
			TPS3-TDP3-FS	1.2E-02
13	0.1	1.6E-07	TPS3-TDP1-FS	1.2E-02
			TPS3-TDP2-FR	3.6E-03
			TPS3-TDP3-MA	3.7E-03
14	0.1	1.6E-07	TPS3-TDP1-FS	1.2E-02
			TPS3-TDP2-MA	3.7E-03
			TPS3-TDP3-FR	3.6E-03
15	0.1	1.6E-07	TPS3-TDP1-MA	3.7E-03
			TPS3-TDP2-FR	3.6E-03
			TPS3-TDP3-FS	1.2E-02
16	0.1	1.6E-07	TPS3-TDP1-MA	3.7E-03
			TPS3-TDP2-FS	1.2E-02
			TPS3-TDP3-FR	3.6E-03
17	0.1	1.5E-07	TPS3-TDP1-FR	3.6E-03
			TPS3-TDP2-FR	3.6E-03
			TPS3-TDP3-FS	1.2E-02
18	0.1	1.5E-07	TPS3-TDP1-FR	3.6E-03
			TPS3-TDP2-FS	1.2E-02
			TPS3-TDP3-FR	3.6E-03
19	0.1	1.5E-07	TPS3-TDP1-FS	1.2E-02
			TPS3-TDP2-FR	3.6E-03
			TPS3-TDP3-FR	3.6E-03

Table D-12. Fussell-Vesely importance measures of the AFW system failure modes (by AFW design class) used in the PRAIPE comparison. The failure mode estimate is the unrecovered failure probability.

		Design Class Importance Measures[a]											
Failure Mode	Failure Probability[b]	1 (1M,1T,2SG)	2 (1M,2T,2SG)	3 (2T,2SG)	4 (2M,1T,2SG)	5 (2M,1T,3SG)	6 (3T,3SG)	7 (1M,1D,4SG)	8 (1M,1T,4SG)	9 (2T,4SG)	10 (2M,1T,4SG)	11 (3M,1T,4SG)	Overall Weighted Average[c]
MOOS-M	1.1E-03	8.0E-02	6.5E-02	—	4.5E-03	2.1E-04	—	1.3E-01	1.3E-01	—	5.3E-03	9.2E-05	2.6E-02
MOOS-T	4.6E-03	1.5E-02	7.7E-03	2.0E-02	6.8E-04	1.8E-04	1.7E-02	—	1.4E-02	2.0E-02	9.8E-04	3.8E-05	5.5E-03
FTO-SUC	3.4E-04	1.2E-01	5.1E-01	8.3E-03	9.1E-01	9.9E-01	4.6E-02	8.3E-02	4.7E-01	8.1E-03	8.9E-01	8.7E-01	7.1E-01
FTS-ST	1.0E-03	4.4E-06	1.2E-05	5.0E-06	2.2E-07	4.3E-08	5.0E-06	—	5.6E-06	4.9E-03	2.7E-07	1.2E-05	1.4E-04
FTS-M	8.1E-04	3.4E-01	3.6E-02	—	1.9E-03	1.5E-04	—	7.0E-02	6.8E-02	—	2.6E-03	2.7E-05	5.1E-02
FTS-T	1.4E-02	6.2E-02	3.4E-02	6.4E-02	2.9E-03	6.7E-04	6.3E-02	—	7.0E-02	6.4E-02	3.7E-03	1.5E-04	2.1E-02
FTS-D	5.7E-03	—	—	—	—	—	—	1.1E-02	—	—	—	—	5.9E-04
FTR-M	2.4E-04/hr	4.2E-01	3.5E-01	—	2.7E-02	3.5E-04	—	6.9E-01	2.7E-01	—	3.2E-02	5.7E-04	1.4E-01
FTR-T	8.2E-03/hr	7.6E-01	4.1E-01	9.0E-01	4.0E-02	1.6E-03	8.5E-01	—	3.9E-01	8.9E-01	5.0E-02	2.2E-03	2.7E-01
FTR-D	2.7E-02/hr	—	—	—	—	—	—	8.8E-01	—	—	—	—	4.9E-02
FTO-INJ	2.4E-03	1.5E-04	1.6E-04	2.1E-05	6.9E-03	6.1E-04	3.6E-07	0.0	1.8E-03	3.3E-04	5.7E-03	6.4E-04	1.1E-02
PMPS-FTR	5.1E-04/hr	3.5E-02	4.0E-02	3.4E-03	4.1E-02	8.2E-03	4.3E-03	2.2E-02	4.3E-02	3.4E-03	5.2E-02	1.6E-02	3.4E-02
MDPS-FTS	3.1E-03	—	—	—	3.1E-03	8.6E-04	—	—	—	—	3.6E-03	1.2E-03	2.0E-03
DIS-SEG	3.0E-03	3.6E-04	1.7E-03	3.4E-05	2.7E-03	3.1E-03	2.4E-04	3.4E-05	7.2E-03	3.5E-05	4.7E-04	1.1E-01	4.6E-03
TD-QT-STM	1.4E-03	4.9E-04	1.3E-03	2.8E-03	2.6E-05	5.8E-06	1.6E-02	—	6.2E-04	2.8E-03	3.2E-05	—	6.4E-04
ALPHA-FTR	note d	3.5E-02	4.0E-02	3.4E-03	4.1E-02	8.2E-03	4.3E-03	2.2E-02	4.3E-02	3.4E-03	5.2E-02	1.6E-02	3.4E-02
ALPHA-FTS	note d	—	—	—	3.1E-03	8.6E-04	—	—	—	—	3.6E-03	1.2E-03	2.0E-03
ALPHA-DISSEG	note d	3.6E-04	1.7E-03	3.4E-05	2.7E-03	3.1E-03	2.4E-04	3.4E-05	7.2E-03	3.5E-05	4.7E-04	1.1E-01	4.6E-03
ALPHA-STM	note d	4.9E-04	1.3E-03	2.8E-03	2.6E-05	5.8E-06	1.6E-02	—	6.2E-04	2.8E-03	3.2E-05	—	6.4E-04
Design class average unreliability[e]		2.0E-03	6.5E-04	3.9E-02	4.2E-04	4.2E-04	7.7E-03	3.2E-03	7.2E-04	3.9E-02	3.8E-04	3.7E-04	2.1E-03

a. The importance measures are Fussell-Vesely measures. The importance measures are for the plant that serves as the reference for the AFW design class. The design class (M,T,SG) defines the number of motor (M), turbine (T), diesel (D) pumps, and steam generators (SG).

b. The failure probability is the mean of the distribution. The estimates are taken from Table D-2 of the main report and represent the arithmetic average of the industry as a whole.

c. The weighted average for a failure mode is the sum of the product of the population fraction and the failure mode importance for the design classes.

d. The common cause failure probabilities are dependent on the size of the common cause groups (e.g., common cause susceptibility of two pumps, three pumps, or four pumps). Specific alpha factors are presented in Table 3

e. The AFW unreliability is the arithmetic average of the plants within an AFW design class.

Table D-13. Failure mode rankings, by Fussell-Vesely importance and AFW design class, of AFW unreliability for PRA/IPE comparison using 1987–1995 experience data.

		Design Class Importance Measures[a]											
Failure Mode	Failure Probability[b]	1 (1M,1T,2SG)	2 (1M,2T,2SG)	3 (2T,2SG)	4 (2M,1T,2SG)	5 (2M,1T,3SG)	6 (3T,3SG)	7 (1M,1D,4SG)	8 (1M,1T,4SG)	9 (2T,4SG)	10 (2M,1T,4SG)	11 (3M,1T,4SG)	Overall Weighted Average[c]
MOOS-M	1.1E-03	5	4	—	6	9	—	3	4	—	6	9	7
MOOS-T	4.6E-03	8	8	3	11	10	4	—	8	3	10	10	10
FTO-SUC	3.4E-04	4	1	4	1	1	3	4	1	4	1	1	1
FTS-ST	1.0E-03	12	12	9	13	13	8	—	12	5	13	12	15
FTS-M	8.1E-04	3	6	—	10	11	—	5	6	—	9	11	4
FTS-T	1.4E-02	6	7	2	8	6	2	—	5	2	7	8	8
FTS-D	5.7E-03	—	—	—	—	—	—	7	—	—	—	—	14
FTR-M	2.4E-04/hr	2	3	—	4	8	—	2	3	—	4	7	3
FTR-T	8.2E-03/hr	1	2	1	3	4	1	—	2	1	3	4	2
FTR-D	2.7E-02/hr	—	—	—	—	—	—	1	—	—	—	—	5
FTO-INJ	2.4E-03	11	11	8	5	7	9	9	10	8	5	6	9
PMPS-FTR	5.1E-04/hr	7	5	5	2	2	6	6	7	6	2	3	6
MDPS-FTS	3.1E-03	—	—	—	7	5	—	—	—	—	8	5	12
DIS-SEG	3.0E-03	10	9	7	9	3	7	8	9	9	11	2	11
TD-QT-STM	1.4E-03	9	10	6	12	12	5	—	11	7	12	—	13
ALPHA-FTR	note d	7	5	5	2	2	6	6	7	6	2	3	6
ALPHA-FTS	note d	—	—	—	7	5	—	—	—	—	8	5	12
ALPHA-DISSEG	note d	10	9	7	9	3	7	8	9	9	11	2	11
ALPHA-STM	note d	9	10	6	12	12	5	—	11	7	12	—	13
Design class average unreliability[e]		4	6	1	7	7	2	3	5	1	8	9	—

a. The importance measures are Fussell-Vesely measures. The importance measures are for the plant that serves as the reference for the AFW design class. The design class (M,T,SG) defines the number of motor (M), turbine (T), diesel (D) pumps, and steam generators (SG).

b. The failure probability is the mean of the distribution. The estimates are taken from Table D-2 of the main report and represent the arithmetic average of the industry as a whole.

c. The weighted average for a failure mode is the sum of the product of the population fraction and the failure mode importance for the design classes.

d. The common cause failure probabilities are dependent on the size of the common cause groups (e.g., common cause susceptibility of two pumps, three pumps, or four pumps). Specific alpha factors are presented in Table3.

e. The AFW unreliability is the arithmetic average of the plants within an AFW design class.

Table D-14. A listing of the cut sets (by reference plant for the eleven AF W design classes) contributing 0.1% or greater to the AFW unreliability (PRA-based mission and 1987–1995 experience).

AFW design class 7
System: Braidwood
Mincut Upper Bound: 4.022E-003

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	68.2	2.7E-03	BRS1-EDP-FR	4.7E-01
			BRS1-MDP-FR	5.8E-03
2	13.2	5.3E-04	BRS1-EDP-FR	4.7E-01
			BRS1-MDP-MA	1.1E-03
3	8.3	3.3E-04	BRS1-CST-SUCT	3.4E-04
4	6.9	2.8E-04	BRS1-EDP-FR	4.7E-01
			BRS1-MDP-FS	6.0E-04
5	2.2	9.0E-05	BRS1-ALPHA-FTR	1.2E-02
			BRS1-PMPS-FTR	7.4E-03
6	0.8	3.3E-05	BRS1-EDP-FS	5.7E-03
			BRS1-MDP-FR	5.8E-03
7	0.1	6.4E-06	BRS1-EDP-FS	5.7E-03
			BRS1-MDP-MA	1.1E-03

AFW design class 2

System: Calvert Cliffs
Mincut Upper Bound: 6.605E-004

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	50.8	3.3E-04	CCN1-CST-SUCT	3.4E-04
2	28.4	1.8E-04	CCN1-MDP-FR	5.8E-03
			CCN1-TDP11-FR	1.8E-01
			CCN1-TDP12-FR	1.8E-01
3	5.5	3.6E-05	CCN1-MDP-MA	1.1E-03
			CCN1-TDP11-FR	1.8E-01
			CCN1-TDP12-FR	1.8E-01
4	4.0	2.6E-05	CCN1-ALPHA-FTR	3.1E-03
			CCN1-PMPS-FTR	8.5E-03
5	2.9	1.9E-05	CCN1-MDP-FS	6.1E-04
			CCN1-TDP11-FR	1.8E-01
			CCN1-TDP12-FR	1.8E-01
6	2.3	1.5E-05	CCN1-MDP-FR	5.8E-03
			CCN1-TDP11-FR	1.8E-01
			CCN1-TDP12-FS	1.5E-02
7	2.3	1.5E-05	CCN1-MDP-FR	5.8E-03
			CCN1-TDP11-FS	1.5E-02
			CCN1-TDP12-FR	1.8E-01

Table D-14. (continued).

Cut No.	Cut Set %	Probability Frequency	Basic Event	Probability
8	0.6	4.2E-06	CCN1-MDP-FR	5.8E-03
			CCN1-TDP11-FR	1.8E-01
			CCN1-TDP12-MA	4.1E-03
9	0.6	4.2E-06	CCN1-MDP-FR	5.8E-03
			CCN1-TDP11-MA	4.1E-03
			CCN1-TDP12-FR	1.8E-01
10	0.4	3.0E-06	CCN1-MDP-MA	1.1E-03
			CCN1-TDP11-FR	1.8E-01
			CCN1-TDP12-FS	1.5E-02
11	0.4	3.0E-06	CCN1-MDP-MA	1.1E-03
			CCN1-TDP11-FS	1.5E-02
			CCN1-TDP12-FR	1.8E-01
12	0.2	1.6E-06	CCN1-MDP-FS	6.1E-04
			CCN1-TDP11-FR	1.8E-01
			CCN1-TDP12-FS	1.5E-02
13	0.2	1.6E-06	CCN1-MDP-FS	6.1E-04
			CCN1-TDP11-FS	1.5E-02
			CCN1-TDP12-FR	1.8E-01
14	0.2	1.3E-06	CCN1-MDP-FR	5.8E-03
			CCN1-TDP11-FS	1.5E-02
			CCN1-TDP12-FS	1.5E-02
15	0.1	1.1E-06	CCN1-ALPHA-DISSG	1.4E-03
			CCN1-DIS-SEG	8.3E-04
16	0.1	6.6E-07	CCN1-ALPHA-STM	8.5E-02
			CCN1-MDP-FR	5.8E-03
			CCN1-TD-QT-STM	1.4E-03

AFW design class 1

System: Crystal River 3
Mincut Upper Bound: 2.724E-003

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	38.4	1.0E-03	CRP3-MDP-FR	5.8E-03
			CRP3-TDP-FR	1.8E-01
2	30.6	8.3E-04	CRP3-MDP-FS	4.6E-03
			CRP3-TDP-FR	1.8E-01
3	12.3	3.3E-04	CRP3-CST-SUCT	3.4E-04
4	7.4	2.0E-04	CRP3-MDP-MA	1.1E-03
			CRP3-TDP-FR	1.8E-01
5	3.5	9.6E-05	CRP3-ALPHA-FTR	1.2E-02
			CRP3-PMPS-FTR	8.0E-03

Table D-14. (continued).

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
6	3.1	8.5E-05	CRP3-MDP-FR	5.8E-03
			CRP3-TDP-FS	1.5E-02
7	2.5	6.8E-05	CRP3-MDP-FS	4.6E-03
			CRP3-TDP-FS	1.5E-02
8	0.8	2.2E-05	CRP3-MDP-FR	5.8E-03
			CRP3-TDP-MA	3.8E-03
9	0.6	1.7E-05	CRP3-MDP-FS	4.6E-03
			CRP3-TDP-MA	3.8E-03
10	0.6	1.6E-05	CRP3-MDP-MA	1.1E-03
			CRP3-TDP-FS	1.5E-02

AFW design class 3

System: Davis-Besse
Mincut Upper Bound: 3.911E-002

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	82.3	3.2E-02	DBS1-TDP1-FR	1.8E-01
			DBS1-TDP2-FR	1.8E-01
2	6.0	2.3E-03	DBS1-TDP1-FR	1.8E-01
			DBS1-TDP2-FS	1.3E-02
3	6.0	2.3E-03	DBS1-TDP1-FS	1.3E-02
			DBS1-TDP2-FR	1.8E-01
4	1.9	7.4E-04	DBS1-TDP1-FR	1.8E-01
			DBS1-TDP2-MA	4.2E-03
5	1.9	7.4E-04	DBS1-TDP1-MA	4.2E-03
			DBS1-TDP2-FR	1.8E-01
6	0.8	3.3E-04	DBS1-CST-SUCT	3.4E-04
7	0.4	1.7E-04	DBS1-TDP1-FS	1.3E-02
			DBS1-TDP2-FS	1.3E-02
8	0.3	1.3E-04	DBS1-ALPHA-FTR	1.2E-02
			DBS1-PMPS-FTR	1.1E-02
9	0.2	1.1E-04	DBS1-ALPHA-STM	8.5E-02
			DBS1-TD-QT-STM	1.4E-03
10	0.1	5.5E-05	DBS1-TDP1-FS	1.3E-02
			DBS1-TDP2-MA	4.2E-03
11	0.1	5.5E-05	DBS1-TDP1-MA	4.2E-03
			DBS1-TDP2-FS	1.3E-02

Table D-14. (continued).

AFW design class 9

System: Haddem Neck
Mincut Upper Bound: 3.960E-002

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	81.3	3.2E-02	HNP1-TDPA-FR	1.8E-01
			HNP1-TDPB-FR	1.8E-01
2	6.0	2.4E-03	HNP1-TDPA-FR	1.8E-01
			HNP1-TDPB-FS	1.3E-02
3	6.0	2.4E-03	HNP1-TDPA-FS	1.3E-02
			HNP1-TDPB-FR	1.8E-01
4	1.9	7.6E-04	HNP1-TDPA-FR	1.8E-01
			HNP1-TDPB-MA	4.3E-03
5	1.9	7.6E-04	HNP1-TDPA-MA	4.3E-03
			HNP1-TDPB-FR	1.8E-01
6	0.8	3.3E-04	HNP1-CST-SUCT	3.4E-04
7	0.4	1.8E-04	HNP1-TDA-STM-SUP	1.0E-03
			HNP1-TDPB-FR	1.8E-01
8	0.4	1.8E-04	HNP1-TDB-STM-SUP	1.0E-03
			HNP1-TDPA-FR	1.8E-01
9	0.4	1.7E-04	HNP1-TDPA-FS	1.3E-02
			HNP1-TDPB-FS	1.3E-02
10	0.3	1.3E-04	HNP1-ALPHA-FTR	1.2E-02
			HNP1-PMPS-FTR	1.2E-02
11	0.2	1.1E-04	HNP1-ALPHA-STM	8.5E-02
			HNP1-TD-QT-STM	1.4E-03
12	0.1	5.7E-05	HNP1-TDPA-FS	1.3E-02
			HNP1-TDPB-MA	4.3E-03
13	0.1	5.7E-05	HNP1-TDPA-MA	4.3E-03
			HNP1-TDPB-FS	1.3E-02

AFW design class 5

System: Joseph M Farley
Mincut Upper Bound: 3.403E-004

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	98.6	3.3E-04	JMF1-CST-SUCT	3.4E-04
2	0.8	2.7E-06	JMF1-ALPHA-FTR	3.1E-03
			JMF1-PMPS-FTR	8.9E-04
3	0.3	1.0E-06	JMF1-ALPHA-DISSG	1.5E-03
			JMF1-DIS-SEG	7.2E-04

Table D-14. (continued).

AFW design class 8

System: Seabrook
Mincut Upper Bound: 7.101E-004

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	47.2	3.3E-04	SBK1-CST-SUCT	3.4E-04
2	22.0	1.5E-04	SBK1-MDP-FR	2.2E-03
			SBK1-TDP-FR	7.2E-02
3	11.3	8.0E-05	SBK1-MDP-MA	1.1E-03
			SBK1-TDP-FR	7.2E-02
4	5.5	3.9E-05	SBK1-MDP-FS	5.5E-04
			SBK1-TDP-FR	7.2E-02
5	4.3	3.0E-05	SBK1-ALPHA-FTR	1.2E-02
			SBK1-PMPS-FTR	2.6E-03
6	3.9	2.8E-05	SBK1-MDP-FR	2.2E-03
			SBK1-TDP-FS	1.3E-02
7	2.0	1.4E-05	SBK1-MDP-MA	1.1E-03
			SBK1-TDP-FS	1.3E-02
8	1.1	8.2E-06	SBK1-MDP-FR	2.2E-03
			SBK1-TDP-MA	3.7E-03
9	0.9	7.0E-06	SBK1-MDP-FS	5.5E-04
			SBK1-TDP-FS	1.3E-02
10	0.7	5.1E-06	SBK1-ALPHA-DISSG	1.4E-03
			SBK1-DIS-SEG	3.8E-03
11	0.2	2.0E-06	SBK1-MDP-FS	5.5E-04
			SBK1-TDP-MA	3.7E-03

AFW design class 10

System: Salem
Mincut Upper Bound: 3.757E-004

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	89.3	3.3E-04	SGS1-CST-SUCT	3.4E-04
2	5.1	1.9E-05	SGS1-ALPHA-FTR	3.1E-03
			SGS1-PMPS-FTR	6.2E-03
3	1.6	6.1E-06	SGS1-MDP11-FR	5.8E-03
			SGS1-MDP12-FR	5.8E-03
			SGS1-TDP-FR	1.8E-01
4	0.4	1.5E-06	SGS1-MD1-SG3-SEG	1.5E-03
			SGS1-MDP12-FR	5.8E-03
			SGS1-TDP-FR	1.8E-01

Table D-14. (continued).

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
5	0.4	1.5E-06	SGS1-MD1-SG4-SEG	1.5E-03
			SGS1-MDP12-FR	5.8E-03
			SGS1-TDP-FR	1.8E-01
6	0.4	1.5E-06	SGS1-MD2-SG1-SEG	1.5E-03
			SGS1-MDP11-FR	5.8E-03
			SGS1-TDP-FR	1.8E-01
7	0.4	1.5E-06	SGS1-MD2-SG2-SEG	1.5E-03
			SGS1-MDP11-FR	5.8E-03
			SGS1-TDP-FR	1.8E-01
8	0.3	1.2E-06	SGS1-ALPHA-MDFTS	2.8E-02
			SGS1-MDPS-FTS	2.4E-04
			SGS1-TDP-FR	1.8E-01
9	0.3	1.1E-06	SGS1-MDP11-FR	5.8E-03
			SGS1-MDP12-MA	1.1E-03
			SGS1-TDP-FR	1.8E-01
10	0.3	1.1E-06	SGS1-MDP11-MA	1.1E-03
			SGS1-MDP12-FR	5.8E-03
			SGS1-TDP-FR	1.8E-01
11	0.1	5.1E-07	SGS1-MDP11-FR	5.8E-03
			SGS1-MDP12-FS	4.9E-04
			SGS1-TDP-FR	1.8E-01
12	0.1	5.1E-07	SGS1-MDP11-FS	4.9E-04
			SGS1-MDP12-FR	5.8E-03
			SGS1-TDP-FR	1.8E-01
13	0.1	4.5E-07	SGS1-MDP11-FR	5.8E-03
			SGS1-MDP12-FR	5.8E-03
			SGS1-TDP-FS	1.3E-02

AFW design class 4

System: St. Lucie
Mincut Upper Bound: 3.681E-004

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	91.2	3.3E-04	SLS1-CST-SUCT	3.4E-04
2	4.1	1.5E-05	SLS1-ALPHA-FTR	3.1E-03
			SLS1-PMPS-FTR	4.9E-03
3	1.6	6.1E-06	SLS1-MDPA-FR	5.8E-03
			SLS1-MDPB-FR	5.8E-03
			SLS1-TDP-FR	1.8E-01
4	0.4	1.5E-06	SLS1-MDA-SGA-SEG	1.5E-03
			SLS1-MDPB-FR	5.8E-03
			SLS1-TDP-FR	1.8E-01

Table D-14. (continued).

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
5	0.4	1.5E-06	SLS1-MDB-SGB-SEG	1.5E-03
			SLS1-MDPA-FR	5.8E-03
			SLS1-TDP-FR	1.8E-01
6	0.3	1.1E-06	SLS1-MDPA-FR	5.8E-03
			SLS1-MDPB-MA	1.1E-03
			SLS1-TDP-FR	1.8E-01
7	0.3	1.1E-06	SLS1-MDPA-MA	1.1E-03
			SLS1-MDPB-FR	5.8E-03
			SLS1-TDP-FR	1.8E-01
8	0.2	1.0E-06	SLS1-ALPHA-MDFTS	2.8E-02
			SLS1-MDPS-FTS	2.1E-04
			SLS1-TDP-FR	1.8E-01
9	0.2	9.9E-07	SLS1-ALPHA-DISSG	1.4E-03
			SLS1-DIS-SEG	7.4E-04
10	0.1	4.3E-07	SLS1-MDPA-FR	5.8E-03
			SLS1-MDPB-FR	5.8E-03
			SLS1-TDP-FS	1.3E-02
11	0.1	4.3E-07	SLS1-MDPA-FR	5.8E-03
			SLS1-MDPB-FS	4.1E-04
			SLS1-TDP-FR	1.8E-01
12	0.1	4.3E-07	SLS1-MDPA-FS	4.1E-04
			SLS1-MDPB-FR	5.8E-03
			SLS1-TDP-FR	1.8E-01
13	0.1	3.8E-07	SLS1-MDA-SGA-SEG	1.5E-03
			SLS1-MDB-SGB-SEG	1.5E-03
			SLS1-TDP-FR	1.8E-01

AFW design class 11

System: South Texas Project
Mincut Upper Bound: 3.866E-004

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	86.8	3.3E-04	STN1-CST-SUCT	3.4E-04
2	11.3	4.3E-05	STN1-ALPHA-DISSG	1.4E-02
			STN1-DIS-SEG	3.3E-03
3	1.5	6.1E-06	STN1-ALPHA-FTR	1.9E-03
			STN1-PMPS-FTR	3.3E-03
4	0.1	3.9E-07	STN1-ALPHA-MDFTS	1.6E-02
			STN1-MDPS-FTS	1.4E-04
			STN1-TDPD-FR	1.8E-01

Table D-14. (continued).

AFW design class 6

System: Turkey Point
Mincut Upper Bound: 7.235E-003

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
1	71.2	5.1E-03	TPS3-TDP1-FR	1.7E-01
			TPS3-TDP2-FR	1.7E-01
			TPS3-TDP3-FR	1.7E-01
2	5.2	3.8E-04	TPS3-TDP1-FR	1.7E-01
			TPS3-TDP2-FR	1.7E-01
			TPS3-TDP3-FS	1.3E-02
3	5.2	3.8E-04	TPS3-TDP1-FR	1.7E-01
			TPS3-TDP2-FS	1.3E-02
			TPS3-TDP3-FR	1.7E-01
4	5.2	3.8E-04	TPS3-TDP1-FS	1.3E-02
			TPS3-TDP2-FR	1.7E-01
			TPS3-TDP3-FR	1.7E-01
5	4.6	3.3E-04	TPS3-CST-SUCT	3.4E-04
6	1.5	1.1E-04	TPS3-ALPHA-STM	8.5E-02
			TPS3-TD-QT-STM	1.4E-03
7	1.5	1.1E-04	TPS3-TDP1-FR	1.7E-01
			TPS3-TDP2-FR	1.7E-01
			TPS3-TDP3-MA	3.7E-03
8	1.5	1.1E-04	TPS3-TDP1-FR	1.7E-01
			TPS3-TDP2-MA	3.7E-03
			TPS3-TDP3-FR	1.7E-01
9	1.5	1.1E-04	TPS3-TDP1-MA	3.7E-03
			TPS3-TDP2-FR	1.7E-01
			TPS3-TDP3-FR	1.7E-01
10	0.4	3.1E-05	TPS3-ALPHA-FTR	3.1E-03
			TPS3-PMPS-FTR	1.0E-02
11	0.3	2.8E-05	TPS3-TDP1-FR	1.7E-01
			TPS3-TDP2-FS	1.3E-02
			TPS3-TDP3-FS	1.3E-02
12	0.3	2.8E-05	TPS3-TDP1-FS	1.3E-02
			TPS3-TDP2-FR	1.7E-01
			TPS3-TDP3-FS	1.3E-02
13	0.3	2.8E-05	TPS3-TDP1-FS	1.3E-02
			TPS3-TDP2-FS	1.3E-02
			TPS3-TDP3-FR	1.7E-01
14	0.1	8.1E-06	TPS3-TDP1-FR	1.7E-01
			TPS3-TDP2-FS	1.3E-02
			TPS3-TDP3-MA	3.7E-03
15	0.1	8.1E-06	TPS3-TDP1-FR	1.7E-01
			TPS3-TDP2-MA	3.7E-03
			TPS3-TDP3-FS	1.3E-02

Table D-14. (continued).

Cut No.	Cut Set %	Probability/ Frequency	Basic Event	Probability
16	0.1	8.1E-06	TPS3-TDP1-FS	1.3E-02
			TPS3-TDP2-FR	1.7E-01
			TPS3-TDP3-MA	3.7E-03
17	0.1	8.1E-06	TPS3-TDP1-FS	1.3E-02
			TPS3-TDP2-MA	3.7E-03
			TPS3-TDP3-FR	1.7E-01
18	0.1	8.1E-06	TPS3-TDP1-MA	3.7E-03
			TPS3-TDP2-FR	1.7E-01
			TPS3-TDP3-FS	1.3E-02
19	0.1	8.1E-06	TPS3-TDP1-MA	3.7E-03
			TPS3-TDP2-FS	1.3E-02
			TPS3-TDP3-FR	1.7E-01

D-7. REFERENCES

D-1. H. M. Stromberg, F. M. Marshall, et al., *Common Cause Failure Data Collection and Analysis System*, Volumes 1 through 6, INEL-94/0064, December 1995.

D-2. IE Bulletin 85-01: *Steam Binding of Auxiliary Feedwater Pumps*, U.S. Nuclear Regulatory Commission, October 29, 1985.

Appendix E

Statistical Analysis Results: Uncertainty Distributions, Common Cause Comparisons, Run Times, and Trends

Appendix E

Statistical Analysis Results: Uncertainty Distributions, Common Cause Comparisons, Run Times, and Trends

This appendix provides more detailed results from the statistical analysis, including relevant AFW failure and demand counts, the results of tests of homogeneity among various groups of data for each failure mode, and information concerning where empirical Bayes distributions were found to describe differences between subgroups of the data. For selected failure modes, plant-specific confidence intervals and empirical Bayes uncertainty intervals are provided.

This appendix also contains a comparison of the common cause information leading to the alpha factors used in the quantification of system unreliability and simple common cause failure (CCF) estimates that are easily derived from the LER data.

Statistical results concerning pump run times are described.

Finally, this appendix provides more information on the AFW system trend evaluations. Two types of trend analyses are given: an investigation of the possible relation between plant low-power license date and AFW performance, and an investigation of whether overall performance changed during the 9 years of the study. The performance is evaluated in terms of the estimated AFW operational unreliability, the frequency of unplanned demands, and the probability of failures on these demands.

E-1. UNCERTAINTY DISTRIBUTIONS

In Sections E-1.1 and E-1.2 below, general statistical results for the individual failure modes in this study are followed by tables with plant-specific data for the failure modes with enough data to model between-plant variation.

E-1.1 Analysis of Individual Failure Modes

Table E-1 contains results from the initial assessment of data for the failure modes evaluated for AFW, including point estimates and confidence bounds for each probability or rate of failure. In the table, modes are listed in sequence across the AFW system, starting with the suction source, then the pump trains, then the flow control segments, steam generator feed segments, and the turbine steam supply. For the pump trains, the results are further subdivided by failure mode, with maintenance followed by failure to start and then failure to run. For failure modes for which recovery was considered, data for the probability of failing to recover follow the data for the particular failure mode. Also, for modes for which differences exist between the data for the risk-based and operational mission, the operational mission data follow the risk-based mission data. Within each group of data, results for motor, turbine, and diesel trains are listed separately, then the pooled results are given. The feed control segment data are listed also by train type, based on the type of train feeding the segment. Here, the pooled results also include data from the common feed segments.

The last section of Table E-1 contains data supporting the quantification of three of the four CCF modes that occurred in the AFW data: the CCF of motor-driven pumps to start, of all types of pumps to run (pump-related failures only), and of feed control segments. This section contains estimates for total

Table E-1. Point estimates and confidence bounds for AFW failure modes (unplanned demands).

Failure Mode	Train Type	Failures f	Demands d[a]	Probability[b]
Failure in suction source (CST)[c]	—	1	1116	(4.6E-05, 9.0E-04, 4.2E-03)
Failure to recover from CST	—	0	1	(0.0E+00, 0.0E+00, 9.5E-01)
Maintenance (MOS)	Motor trains	4	1995	(6.9E-04, 2.0E-03, 4.6E-03)
	Turbine trains	5	602	(3.3E-03, 8.3E-03, 1.7E-02)
	Diesel trains	0	65	(0.0E+00, 0.0E+00, 4.5E-02)
	Pooled	9	2662	(1.8E-03, 3.4E-03, 5.9E-03)
Failure to recover from MOS	Motor trains	2	4	(9.8E-02, 5.0E-01, 9.0E-01)
	Turbine trains	3	5	(1.9E-01, 6.0E-01, 9.2E-01)
	Pooled	5	9	(2.5E-01, 5.6E-01, 8.3E-01)
Failure to start (FTS), independent only (risk-based model) (IFTS)	Motor trains	6	1993	(1.3E-03, 3.0E-03, 5.9E-03)
	Turbine trains	17	597	(1.8E-02, 2.8E-02, 4.2E-02)
	Diesel trains	1	65	(7.9E-04, 1.5E-02, 7.1E-02)
	Pooled	24	2655	(6.2E-03, 9.0E-03, 1.3E-02)
Failure to recover from IFTS	Motor trains	1	6	(8.5E-03, 1.7E-01, 5.8E-01)
	Turbine trains	8	17	(2.6E-01, 4.7E-01, 6.9E-01)
	Diesel trains	0	1	(0.0E+00, 0.0E+00, 9.5E-01)
	Pooled	9	24	(2.1E-01, 3.8E-01, 5.6E-01)
FTS, independent only (operational model) (ISOP)	Motor trains	6	1993	(1.3E-03, 3.0E-03, 5.9E-03)
	Turbine trains	16	597	(1.7E-02, 2.7E-02, 4.0E-02)
	Diesel trains	1	65	(7.9E-04, 1.5E-02, 7.1E-02)
	Pooled	23	2655	(5.9E-03, 8.7E-03, 1.2E-02)
Failure to recover from ISOP	Motor trains	1	6	(8.5E-03, 1.7E-01, 5.8E-01)
	Turbine trains	8	16	(2.8E-01, 5.0E-01, 7.2E-01)
	Diesel trains	0	1	(0.0E+00, 0.0E+00, 9.5E-01)
	Pooled	9	23	(2.2E-01, 3.9E-01, 5.8E-01)
Failure to run (FTR), independent only (rate, per hour) (risk-based model)(FTRR) (see Note d)	Motor trains	1	4617.960	(1.1E-05, 2.2E-04, 1.0E-03)
	Turbine trains	3	371.487	(2.2E-03, 8.1E-03, 2.1E-02)
	Diesel trains	1	42.390	(1.2E-03, 2.4E-02, 1.1E-01)
	Pooled	5	5031.836	(3.9E-04, 9.9E-04, 2.1E-03)
Failure to recover from FTRR	Motor trains	1	1	(5.0E-02, 1.0E+00, 1.0E+00)
	Diesel trains	1	1	(5.0E-02, 1.0E+00, 1.0E+00)
	Turbine trains	3	3	(3.7E-01, 1.0E+00, 1.0E+00)
	Pooled	5	5	(5.5E-01, 1.0E+00, 1.0E+00)
FTR, independent only (operational model) (INOP)	Motor trains	1	1987	(2.6E-05, 5.0E-04, 2.4E-03)
	Turbine trains	2	583	(6.1E-04, 3.4E-03, 1.1E-02)
	Diesel trains	0	65	(0.0E+00, 0.0E+00, 4.5E-02)
	Pooled	3	2635	(3.1E-04, 1.1E-03, 2.9E-03)
Failure to recover from INOP	Motor trains	1	1	(5.0E-02, 1.0E+00, 1.0E+00)
	Turbine trains	2	2	(2.2E-01, 1.0E+00, 1.0E+00)
	Pooled	3	3	(3.7E-01, 1.0E+00, 1.0E+00)
Common feed control segment failures (FCM), indep. only (IFCM)	—	5	886	(2.2E-03, 5.6E-03, 1.2E-02)
Failure to recover from IFCM	—	2	5	(7.6E-02, 4.0E-01, 8.1E-01)
Feed control segment failures (FD), independent only (IFD)	Motor trains	16	3013	(3.3E-03, 5.3E-03, 8.1E-03)
	Turbine trains	1	1067	(4.8E-05, 9.4E-04, 4.4E-03)
	Diesel trains	0	260	(0.0E+00, 0.0E+00, 1.1E-02)
	Pooled, incl. common[e]	22	5226	(2.9E-03, 4.2E-03, 6.0E-03)

Table E-1. (continued).

Failure Mode	Train Type	Failures f	Demands d[a]	Probability[b]
Failure to recover from IFD	Motor trains	8	16	(2.8E-01, 5.0E-01, 7.2E-01)
	Turbine trains	1	1	(5.0E-02, 1.0E+00, 1.0E+00)
	Pooled, incl. common	11	22	(3.1E-01, 5.0E-01, 6.9E-01)
Steam generator feed segment failures (SG), independent only (ISG)	—	0	2148	(0.0E+00, 0.0E+00, 1.4E-03)
Failure to recover from ISG	—	0	0	NA
Turbine steam supply failures (TST), independent only (ITST)	—	1	1108	(4.6E-05, 9.0E-04, 4.3E-03)
Failure to recover from ITST	—	1	1	(5.0E-02, 1.0E+00, 1.0E+00)
Data supporting the common cause failure (CCF) assessment:				
FTS, total failures (FTS)	Motor trains	10	1993	(2.7E-03, 5.0E-03, 8.5E-03)
Failure to recover from FTS CCF events	Motor trains	1[f]	2[f]	(2.5E-02, 5.0E-01, 9.7E-01)
FTR, total pump failures (rate, per	Motor trains	3	4617.960	(1.8E-04, 6.5E-04, 1.7E-03)
hour) (risk-based model)	Diesel trains	0	42.390	(0.0E+00, 0.0E+00, 6.8E-02)
(see Note c)	Turbine trains	0	371.487	(0.0E+00, 0.0E+00, 8.0E-03)
	Pooled	3	5031.836	(1.6E-04, 6.0E-04, 1.5E-03)
FTR, total pump failures (operational	Motor trains	1	1987	(2.6E-05, 5.0E-04, 2.4E-03)
model)	Turbine trains	0	583	(0.0E+00, 0.0E+00, 5.1E-03)
	Diesel trains	0	65	(0.0E+00, 0.0E+00, 4.5E-02)
	Pooled	1	2635	(1.9E-05, 3.8E-04, 1.8E-03)
Failure to recover from pump-related FTR CCF events	—	1[f]	1[f]	(5.0E-02, 1.0E+00, 1.0E+00)
FCM total failures	—	7	886	(3.7E-03, 7.9E-03, 1.5E-02)
FD total failures (risk-based model) (FD)	Motor trains	24	3013	(5.5E-03, 8.0E-03, 1.1E-02)
	Turbine trains	1	1067	(4.8E-05, 9.4E-04, 4.4E-03)
	Diesel trains	0	260	(0.0E+00, 0.0E+00, 1.1E-02)
	Pooled, incl. common	32	5226	(4.5E-03, 6.1E-03, 8.2E-03)
FD total failures (operational model)	Motor trains	20	3013	(4.4E-03, 6.6E-03, 9.6E-03)
	Turbine trains	1	1067	(4.8E-05, 9.4E-04, 4.4E-03)
	Diesel trains	0	260	(0.0E+00, 0.0E+00, 1.1E-02)
	Pooled, incl. common	28	5226	(3.8E-03, 5.4E-03, 7.3E-03)
Failure to recover from FD (including common) CCF events	—	2[f]	4[f]	(9.8E-02, 5.0E-01, 9.0E-01)

a. Except for FTRR and FTPR, for which running time in hours is given.

b. The middle number is the point estimate, *f/d*, and the two end numbers form a 90% confidence interval.

c. The acronyms are used in the statistical software, and are not identical to those used in the fault trees.

d. The 90% confidence interval for the failure rate was derived based on a Poisson distribution for the occurrence of failures.

e. “Incl. common” means including common feed control segments.

f. The demands are the number of events among the unplanned demands for which common cause failure occurred. The failures are the subset of these events for which no trains were recovered from the control room.

failures, rather than independent failures. Alpha factors are multiplied by the respective total component failure probabilities in order to estimate the probabilities of CCF. In the AFW study, these probabilities were combined with the probabilities of failure to recover from CCF events. Since certain failure mechanisms (such as intrusion by clams) are not easily recovered and are more likely to cause multiple failures than single failures, recovery from CCF events was estimated based just on the CCF events that occurred among the unplanned demands. The demand and failure counts for recovery in this section of the table are counts of events rather than individual failures and demands.

The single CCF mode not described in the last section of Table E-1 is the CCF of turbine steam supply segments. For this failure mode, the total failure probability estimate was the same as the independent failure probability estimate listed at the end of the first section of the table. Although a failure occurred in the operational data that affected both supply segments at two units at one station, and therefore this failure mode was included in the AFW unreliability models, the failure was among the surveillance tests. No CCFs occurred among the unplanned demands. Recovery from this CCF failure mode was not modeled, since no opportunities for such recovery occurred in the unplanned demands.

Note that the point estimate and bounds in Table E-1 do not consider any special sources of variation (e.g., year or plant).

Table E-2 summarize the results from testing the hypothesis of constant probabilities or rates across groupings for each failure mode. The rows in Table E-2 are in the same order as the rows in Table E-1. Differences in failure probabilities or rates among train types, plants, calendar years, and AFW design classes were considered. Low probability values (P-values) indicate significant differences or variation. The table also shows where empirical Bayes distributions were found for variation between plants, years, and AFW design classes. Results from this statistical evaluation are discussed in Sections E-1.1.1 through E-1.1.5 below.

E-1.1.1 Differences in Train Type

The rows in Table E-2 describing pooled data contain evaluations of significant differences in the performance of different types of trains in the AFW system. Highly significant differences are seen in the independent failure to start probabilities for the different trains. Table E-1 shows that turbine and diesel trains have a much higher average failure probability than motor trains. The other most significant difference in train type is for failure to run for the risk-based model. Here, the average failure rate is highest for diesel trains and lowest for motor trains. For maintenance, turbine trains had a higher average unavailability, although the difference is not statistically significant. From these statistical results, and from known differences in the design and maintenance of diesel, turbine, and motor pumps, the maintenance, failure to start, and failure to run data were not pooled across train types to estimate the AFW system unreliability.

The probabilities of failure to recover from maintenance, failure to start, and failure to run are all too sparse in the operational data to observe differences across train types. These data also were not pooled across train type because of known differences in the designs. For each train type, and each failure mode (maintenance, starting, and running), a separate independent failure probability was estimated. If one or more failures were observed, the failure probability was combined with its own failure to recover estimate. Failure to recover was not estimated for the two diesel train modes in Table E-1 for which no failures occurred.

Table E-2. Evaluation of differences between groups for AFW failure modes.

Failure Mode	Train Type	P-Values for Test of Variation[a]: In Train Types	In Plant Units	In Years	In AFW Design Classes	Entities with High Chi-Square Statistics[b]
Failure in suction from CSST (CST)	—	—	1.000	0.649	0.999	
Failure to recover from CST[c]	—	—	0 F	0 F	0 F	
Maintenance (MOS)	Motor trains	—	0.527	0.540	0.994	
	Turbine trains	—	0.915 (E)	0.588	0.565	
	Pooled	0.059	0.291 (E)	0.538	**0.028**	Class 6 (2 f, 54 d)
Failure to recover from MOS	Motor trains	—	0.261	0.368	0.135	
	Turbine trains	—	0.405	0.659	0.659	
	Pooled	0.764	0.550	0.570	0.591	
Failure to start (FTS), independent only (risk-based model) (IFTS)	Motor trains	—	**0.000** (E)	0.672	0.866	Harris 1 (3, 14)
	Turbine trains	—	0.740 (E)	0.200 (E)	0.868	
	Diesel trains	—	0.412	0.985	—[d]	
	Pooled	**0.000**	0.413	0.123 (E)	0.852	
Failure to recover from IFTS	Motor trains	—	0.199	0.112	0.753	
	Turbine trains	—	0.502	0.169 (E)	0.455	
	Diesel trains	—	0 F	0 F	—	
	Pooled	0.305	0.390	0.082 (E)	0.570	
FTS, independent only (operational model) (ISOP)	Motor trains	—	0.000 (E)	0.672	0.866	Harris 1 (3, 14)
	Turbine trains	—	0.676 (E)	0.257 (E)	0.821	
	Diesel trains	—	0.412	0.985	—	
	Pooled	**0.000**	0.312 (E)	0.178 (E)	0.790	
Failure to recover from ISOP	Motor trains	—	0.199	0.112	0.753	
	Turbine trains	—	0.5001	0.156 (E)	0.354	
	Diesel trains	—	0 F	0 F	—	
	Pooled	0.258	0.382	0.090 (E)	0.505	
Failure to run (FTR), independent only (rate, per hour) (risk-based model) (FTRR)	Motor trains	—	0.365	0.492	0.514	
	Turbine trains	—	0.556	0.598	0.381	
	Diesel trains	—	0.456	0.985	—	
	Pooled	**0.000**	**0.005** (E)	0.583	**0.039**	(pooled not used)
Failure to recover from FTRR	Motor trains	—	All F	All F	All F	
	Turbine trains	—	All F	All F	All F	
	Diesel trains	—	All F	All F	—	
	Pooled	All F	All F	All F	All F	
FTR, independent only (operational model) (INOP)	Motor trains	—	0.377	0.517	0.528	
	Turbine trains	—	0.673	0.567	0.092	
	Diesel trains	—	0 F	0 F	—	
	Pooled	0.176	0.057	0.733	**0.036**	(pooled not used)
Failure to recover from (INOP)	Motor trains	—	All F	All F	All F	
	Turbine trains	—	All F	All F	All F	
	Pooled	All F	All F	All F	All F	
Common feed control segment failures (FCM), indep. (IFCM)	—	—	**0.000** (E)	0.911	0.203 (E)	Oconee 1 (2, 18) Oconee 2 (1, 10)
Failure to recov. from IFCM	—	—	0.172	0.287	0.082	
Feed control segment failures (FD), independent only (IFD)	Motor trains	—	0.059 (E)	0.239 (E)	0.481	
	Turbine trains	—	0.209	0.665	0.996	
	Diesel trains	—	0 F	0 F	—	
	Pooled, incl. common[e]	0.163	**0.000** (E)	0.109	0.264 (E)	Oconee 1 (2, 18)
Failure to recover from IFD	Motor trains	—	0.051 (E)	0.529	0.572	
	Turbine trains	—	All F	All F	All F	
	Pooled, incl. common	0.549	0.067 (E)	0.261	0.538	

Table E-2. (continued).

Failure Mode	Train Type	P-Values for Test of Variation[a]: In Train Types	In Plant Units	In Years	In AFW Design Classes	Entities with High Chi-Square Statistics[b]
Failure to recover from ISG	—	—	—	—	—	
Turbine steam supply failure (TST), independent only (ITST)	—	—	0.856	0.088	0.003	Class 2 (1,42)
Failure to recover from ITST	—	—	All F	All F	All F	
Data supporting the common cause failure (CCF) assessment:						
FTS, total failures (FTS)	Motor trains	—	**0.000** (E)	0.574	0.914	Indian Pt 2 (3, 24)
Failure to recover from FTS CCF events	Motor trains	—	0.157	0.157	0.157	
FTR, total pump failures (rate, per hour) (risk-based model)	Motor trains	—	**0.001**	0.289	0.547	(pooled was used)
	Turbine trains	—	0 F	0 F	0 F	
	Diesel trains	—	0 F	0 F	0 F	
	Pooled	0.874	**0.001** (E)	0.285 (E)	0.810 (E)	Surry 2 (2, 73.4 h)
FTR, total pump failures (operational model)	Motor trains	—	0.377	0.517	0.528	
	Turbine trains	—	0 F	0 F	0 F	
	Diesel trains	—	0 F	0 F	0 F	
	Pooled	0.849	0.437	0.500	0.813	
Failure to recover from pump-related FTR CCF events	—	—	All F	All F	All F	
FCM total failures	—	—	**0.003** (E)	0.849	0.555	(pooled was used)
FD total failures (risk-based model) (FD)	Motor trains	—	**0.033** (E)	0.656	0.270 (E)	(pooled was used)
	Turbine trains	—	0.209	0.665	0.996	
	Diesel trains	—	0 F	0 F	—	
	Pooled, incl. common	0.037	**0.000** (E)	0.652	0.453 (E)	Oconee 2 (2, 18) Cook 2 (4, 104)
FD total failures (operational model)	Motor trains	—	0.215 (E)	0.451	0.395 (E)	
	Turbine trains	—	0.209	0.665	0.996	
	Diesel trains	—	0 F	0 F	—	
	Pooled, incl. common	0.063	**0.000** (E)	0.473	0.532	Oconee 2 (2, 18) Wolf Creek (4,146)
Failure to recover from FD (and common) CCF events	—	—	0.135	0.135	0.248	

a. —, not applicable; 0 F, no failures (thus, no test); All F, no successes (thus, no test); 0.000, less than 5E-04. P-values less than or equal to 0.05 are in a bold font. An “E” is in parentheses after the P-value if and only if an empirical Bayaes distribution was found accounting for variations in groupings.

b. Groupings with an unusual failure probability (compared to others in the group) are flagged. Unusual means statistically significant at the 5% level, and unless noted otherwise, it was unusually high (versus low). The number of failures and demands (or time) is listed as an ordered pair in parentheses after each group.

c. The acronyms are used in the statistical software, and are not identical to those used in the fault trees.

d. No AAFW design class evaluations are possible for diesel trains since they represent just one plant class.

e. “Incl. common” means including common feed control segments.

The feed control segment data were also evaluated to see if they could be pooled across train type. The average failure probability is similar for feed control segments coming from motor trains, and from trains of different types (common trains). Both failure probability estimates are near 5.5E-03. The estimate is somewhat lower for segments from turbine trains. No failures and relatively few demands were observed for diesel trains. Overall, the P-value is not significant. The types of components in the feed control segments are similar, regardless of the type of pump train feeding the segment. Therefore, these data were pooled across train type. The recovery data were also pooled since no significant differences were seen.

In the data for the common cause evaluation, stronger evidence of differences between feed control segments was seen. Table E-2 shows mildly significant differences among feed segments from motor, turbine, and diesel trains (the P-value for the risk-based model is 0.037, significant at the 5% level, and the P-value for the operational model is 0.063). In the risk-based model, the motor train total failure average is nearly a factor of 10 higher than the turbine train total failure average (8E-03 versus 9E-04). These data were pooled in spite of the statistical indications, for three reasons. First, the statistical evidence for differences is weak. The presence of a P-value less than 0.05 can be expected in any set of 20 significance tests, even when no differences exist. Second, as stated above, the general features of the design of the various feed control segments do not depend on the type of pump train feeding the segments. Finally, in the common cause evaluation, the possibility of common cause events across multiple feed control segments, including segments from different pump trains, is considered.

E-1.1.2 Differences in Plants

Although Table E-2 shows the P-values and presence of empirical Bayes distributions for all of the data sets listed in Table E-1, the evaluation of differences between plants focuses on the rows in the table that are identified for the AFW unreliability analysis, based on train type. More specifically, the pooled rows for maintenance, failure to start, and failure to run are not relevant, and the train-specific rows for the feed control segments are not relevant.

Among the remaining rows, every empirical Bayes distribution found for differences in plants was used in the AFW unreliability analysis. No instances of low P-values with no empirical Bayes distribution occurred in the data. Where the P-values are low, the empirical Bayes distributions accounted adequately for the between-plant variation. After accounting for the fact that there are 72 plants in the study, and thus 72 opportunities for a plant to be an outlier for a failure mode, no low P-values were found in the tests of whether any plant is an outlier from the assumed beta-binomial model or, for the risk-based failure to run, the assumed gamma-Poisson model. The 10 empirical Bayes distributions used in this study are listed, with plant-specific Bayesian updated probabilities and bounds, in the tables in Section E-1.2.

E-1.1.3 Differences in Years

Table E-2 shows no instances of low P-values for the evaluation of differences in years in the study period from 1987 to 1995. Empirical Bayes distributions for differences between years were found in some cases. Where distributions for both plant and year were found, the between-plant distributions were wider, indicating greater between-plant variation than between-year variation. Therefore, the plant distributions were used in the study. The empirical Bayes distributions fitted to the industry for differences between years were used for failure to recover from turbine train failure to start, for both the risk-based and operational models. These were the only two failure modes in the study for which no empirical Bayes distribution was found for between-plant differences, and a distribution was found for between-year differences. The two empirical Bayes distributions were slightly wider than the associated simple Bayes distributions.

E-1.1.4 Differences in AFW Design Classes

Among the rows selected for the analysis, a significant difference with respect to AFW design class was found only for failures of the turbine steam supply. Here, one failure occurred in a total of 1,108 demands. The failure occurred at Calvert Cliffs 2, a Class 2 plant (with two turbine trains and one motor train). The two Calvert Cliffs units are the only units with this AFW design. Only 42 of the 1,108 demands were associated with Calvert Cliffs plants. Having the one failure in a design class with only 3.8 percent of the demands would only be expected 3.8 percent of the time, in the absence of a plant design effect. The failure was caused by a degraded control switch. Because the turbine steam supply part of the Calvert Cliffs design is not unique, and because a single failure represents sparse data, no particular significance from an engineering point of view is attributed to this finding at this time.

In every case for which empirical Bayes distributions describing differences in plant design classes were found, empirical Bayes distributions for differences between plants were found, and the differences between plants were more significant. That is, the P-values for tests of differences between plants were lower than the tests for differences between plant classes. The plant empirical Bayes distributions accounted for more variability than the design class distributions. Therefore, the between-plant distributions were used in the analysis. None of the empirical Bayes distributions for differences between plant classes were used in the unreliability analysis.

E-1.1.5 Summary of Distributions for Individual Failure Modes

Tables 4 and 9 in the body of this report describe the Bayes distributions selected to describe the statistical variability in the data used to model the AFW system unreliability. These tables differ from Table E-1 because they give Bayes distributions and intervals, not confidence intervals. This choice allows the results for the failure modes to be combined to give uncertainty distributions on the risk-based and operational unreliabilities.

E-1.2 Plant-Specific Failure Probabilities and Rates

The tables in this section (Tables E-3 through E-12) provide plant-specific basic event failure probabilities for the failure modes where such variation could be modeled. They also give plant-specific rates for the occurrence of pump-related failures to run, pooled across the three types of pump trains. The 10 tables are as follows:

- Maintenance-out-of-service for turbine trains (five failures, 602 demands)
- Independent failures to start:
  - Motor trains (6 failures, 1,993 demands)
  - Turbine trains:
    - Risk-based model (17 failures, 597 demands)
    - Operational model (16 failures, 597 demands)
- Failures to start, total failures, motor trains (used with common cause alpha factor) (10 failures, 1,993 demands) (total FTS for turbine trains is the same as independent FTS—there were no common cause failures)

- Independent failure of feed segment (22 failures, 5,226 demands)

- Recovery from independent failure of feed segment (11 failures, 22 demands)

  Total failure of feed segment (used with common cause alpha factor):
  - Risk-based model (32 failures, 5,226 demands)
  - Operational model (28 failures, 5,226 demands)

- Total pump-related failure to run for risk-based model (used with common cause alpha factor) (rate) (three failures, 5,031.8 h).

For all other AFW failure modes, significant variation was not observed between plants.

The data are modeled as being homogeneous within each plant. Each plant's data are Bayesian updates of the overall PWR performance described by the empirical Bayes fitted distribution on the bottom line of the table. The plant distributions are obtained as described in Sections A-3.1.5 and A-3.1.6 of Appendix A. The tables also give plant-specific raw failure data: failure counts, demand counts or run times, probability or rate estimates, and confidence intervals.

Note that the empirical Bayes intervals are more consistent with each other than the confidence intervals are, because the empirical Bayes method pulls the extreme plant probabilities or rates toward the general population. If one believes that only the data from a particular plant is relevant for estimating the failure probability for that plant, the confidence intervals should be used. If instead one believes that the plants belong to a population with individual differences but still a family resemblance to each other, the empirical Bayes intervals should be used.

Each table contains a row for each plant, as well as a line showing overall PWR probabilities or rates. Rows for plants that do not have the AFW train type under consideration, such as plants that have diesel instead of turbine trains, have zero failures, zero demands, and no Bayesian distribution listed. Other plants with no failures and no demands have the industry profile from the bottom row of the table in the Bayesian distribution columns.

Table E-3. Probability of maintenance-out-of-service for turbine trains, by plant.

Plant	Failures (*f*)	Demands (*d*)	Estimate (*f/d*) and C.I.[a]	Alpha	Beta	Bayes Mean and Interval
Arkansas 1	0	12	(0.0E+00, 0.0E+00, 2.2E-01)	0.5	70.4	(2.2E-05, 6.8E-03, 2.6E-02)
Arkansas 2	0	10	(0.0E+00, 0.0E+00, 2.6E-01)	0.5	69.3	(2.4E-05, 7.0E-03, 2.7E-02)
Beaver Valley 1	0	16	(0.0E+00, 0.0E+00, 1.7E-01)	0.5	72.4	(1.9E-05, 6.5E-03, 2.5E-02)
Beaver Valley 2	0	27	(0.0E+00, 0.0E+00, 1.1E-01)	0.4	76.3	(1.1E-05, 5.8E-03, 2.3E-02)
Braidwood 1	0	0	—	—	—	—
Braidwood 2	0	0	—	—	—	—
Byron 1	0	0	—	—	—	—
Byron 2	0	0	—	—	—	—
Callaway	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	0.5	64.3	(2.9E-05, 7.6E-03, 2.9E-02)
Calvert Cliffs 1	0	10	(0.0E+00, 0.0E+00, 2.6E-01)	0.5	69.3	(2.4E-05, 7.0E-03, 2.7E-02)
Calvert Cliffs 2	0	11	(0.0E+00, 0.0E+00, 2.4E-01)	0.5	69.9	(2.3E-05, 6.9E-03, 2.7E-02)
Catawba 1	0	4	(0.0E+00, 0.0E+00, 5.3E-01)	0.5	65.1	(2.8E-05, 7.5E-03, 2.9E-02)
Catawba 2	0	32	(0.0E+00, 0.0E+00, 8.9E-02)	0.4	77.6	(8.9E-06, 5.5E-03, 2.2E-02)
Comanche Peak 1	0	8	(0.0E+00, 0.0E+00, 3.1E-01)	0.5	68.1	(2.6E-05, 7.2E-03, 2.8E-02)
Comanche Peak 2	0	1	(0.0E+00, 0.0E+00, 9.5E-01)	0.5	62.5	(2.9E-05, 7.8E-03, 3.0E-02)
Cook 1	0	5	(0.0E+00, 0.0E+00, 4.5E-01)	0.5	65.9	(2.8E-05, 7.4E-03, 2.9E-02)
Cook 2	0	9	(0.0E+00, 0.0E+00, 2.8E-01)	0.5	68.7	(2.5E-05, 7.1E-03, 2.7E-02)
Crystal River 3	0	16	(0.0E+00, 0.0E+00, 1.7E-01)	0.5	72.4	(1.9E-05, 6.5E-03, 2.5E-02)
Davis-Besse	0	8	(0.0E+00, 0.0E+00, 3.1E-01)	0.5	68.1	(2.6E-05, 7.2E-03, 2.8E-02)
Diablo Canyon 1	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	0.5	66.7	(2.7E-05, 7.3E-03, 2.8E-02)
Diablo Canyon 2	0	1	(0.0E+00, 0.0E+00, 9.5E-01)	0.5	62.5	(2.9E-05, 7.8E-03, 3.0E-02)
Farley 1	0	5	(0.0E+00, 0.0E+00, 4.5E-01)	0.5	65.9	(2.8E-05, 7.4E-03, 2.9E-02)
Farley 2	0	1	(0.0E+00, 0.0E+00, 9.5E-01)	0.5	62.5	(2.9E-05, 7.8E-03, 3.0E-02)
Fort Calhoun	0	2	(0.0E+00, 0.0E+00, 7.8E-01)	0.5	63.4	(2.9E-05, 7.7E-03, 3.0E-02)
Ginna	0	8	(0.0E+00, 0.0E+00, 3.1E-01)	0.5	68.1	(2.6E-05, 7.2E-03, 2.8E-02)
Haddam Neck	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	0.5	66.7	(2.7E-05, 7.3E-03, 2.8E-02)
Harris	1	15	(3.4E-03, 6.7E-02, 2.8E-01)	0.6	33.2	(2.0E-04, 1.8E-02, 6.4E-02)
Indian Point 2	0	1	(0.0E+00, 0.0E+00, 9.5E-01)	0.5	62.5	(2.9E-05, 7.8E-03, 3.0E-02)
Indian Point 3	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	0.5	66.7	(2.7E-05, 7.3E-03, 2.8E-02)
Kewaunee	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	0.5	64.3	(2.9E-05, 7.6E-03, 2.9E-02)
Maine Yankee	0	0	—	0.6	70.4	(5.8E-05, 8.0E-03, 2.9E-02)
Mcguire 1	1	7	(7.3E-03, 1.4E-01, 5.2E-01)	0.5	24.3	(7.9E-05, 2.0E-02, 7.7E-02)
Mcguire 2	0	4	(0.0E+00, 0.0E+00, 5.3E-01)	0.5	65.1	(2.8E-05, 7.5E-03, 2.9E-02)
Millstone 2	0	0	—	0.6	70.4	(5.8E-05, 8.0E-03, 2.9E-02)
Millstone 3	1	9	(5.7E-03, 1.1E-01, 4.3E-01)	0.5	26.4	(1.0E-04, 2.0E-02, 7.3E-02)
North Anna 1	0	10	(0.0E+00, 0.0E+00, 2.6E-01)	0.5	69.3	(2.4E-05, 7.0E-03, 2.7E-02)
North Anna 2	0	9	(0.0E+00, 0.0E+00, 2.8E-01)	0.5	68.7	(2.5E-05, 7.1E-03, 2.7E-02)
Oconee 1	0	5	(0.0E+00, 0.0E+00, 4.5E-01)	0.5	65.9	(2.8E-05, 7.4E-03, 2.9E-02)
Oconee 2	0	7	(0.0E+00, 0.0E+00, 3.5E-01)	0.5	67.4	(2.6E-05, 7.2E-03, 2.8E-02)
Oconee 3	0	7	(0.0E+00, 0.0E+00, 3.5E-01)	0.5	67.4	(2.6E-05, 7.2E-03, 2.8E-02)
Palisades	0	1	(0.0E+00, 0.0E+00, 9.5E-01)	0.5	62.5	(2.9E-05, 7.8E-03, 3.0E-02)
Palo Verde 1	0	0	—	0.6	70.4	(5.8E-05, 8.0E-03, 2.9E-02)
Palo Verde 2	0	4	(0.0E+00, 0.0E+00, 5.3E-01)	0.5	65.1	(2.8E-05, 7.5E-03, 2.9E-02)
Palo Verde 3	0	2	(0.0E+00, 0.0E+00, 7.8E-01)	0.5	63.4	(2.9E-05, 7.7E-03, 3.0E-02)
Point Beach 1	0	0	—	0.6	70.4	(5.8E-05, 8.0E-03, 2.9E-02)
Point Beach 2	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	0.5	64.3	(2.9E-05, 7.6E-03, 2.9E-02)

Table E-3. (continued).

Plant	Failures (f)	Demands (d)	Estimate (f/d) and C.I.[a]	Alpha	Beta	Bayes Mean and Interval
Prairie Island 1	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	0.5	64.3	(2.9E-05, 7.6E-03, 2.9E-02)
Prairie Island 2	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	0.5	66.7	(2.7E-05, 7.3E-03, 2.8E-02)
Robinson 2	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	0.5	64.3	(2.9E-05, 7.6E-03, 2.9E-02)
Salem 1	0	4	(0.0E+00, 0.0E+00, 5.3E-01)	0.5	65.1	(2.8E-05, 7.5E-03, 2.9E-02)
Salem 2	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	0.5	66.7	(2.7E-05, 7.3E-03, 2.8E-02)
San Onofre 2	0	7	(0.0E+00, 0.0E+00, 3.5E-01)	0.5	67.4	(2.6E-05, 7.2E-03, 2.8E-02)
San Onofre 3	0	9	(0.0E+00, 0.0E+00, 2.8E-01)	0.5	68.7	(2.5E-05, 7.1E-03, 2.7E-02)
Seabrook	0	17	(0.0E+00, 0.0E+00, 1.6E-01)	0.5	72.8	(1.8E-05, 6.4E-03, 2.5E-02)
Sequoyah 1	0	14	(0.0E+00, 0.0E+00, 1.9E-01)	0.5	71.4	(2.1E-05, 6.6E-03, 2.6E-02)
Sequoyah 2	0	20	(0.0E+00, 0.0E+00, 1.4E-01)	0.5	74.0	(1.6E-05, 6.2E-03, 2.4E-02)
South Texas 1	0	23	(0.0E+00, 0.0E+00, 1.2E-01)	0.5	75.0	(1.4E-05, 6.0E-03, 2.4E-02)
South Texas 2	0	29	(0.0E+00, 0.0E+00, 9.8E-02)	0.4	76.8	(1.0E-05, 5.6E-03, 2.3E-02)
St. Lucie 1	0	15	(0.0E+00, 0.0E+00, 1.8E-01)	0.5	71.9	(2.0E-05, 6.6E-03, 2.6E-02)
St. Lucie 2	0	10	(0.0E+00, 0.0E+00, 2.6E-01)	0.5	69.3	(2.4E-05, 7.0E-03, 2.7E-02)
Summer	0	7	(0.0E+00, 0.0E+00, 3.5E-01)	0.5	67.4	(2.6E-05, 7.2E-03, 2.8E-02)
Surry 1	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	0.5	66.7	(2.7E-05, 7.3E-03, 2.8E-02)
Surry 2	0	4	(0.0E+00, 0.0E+00, 5.3E-01)	0.5	65.1	(2.8E-05, 7.5E-03, 2.9E-02)
Three Mile Isl 1	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	0.5	64.3	(2.9E-05, 7.6E-03, 2.9E-02)
Turkey Point 3	0	18	(0.0E+00, 0.0E+00, 1.5E-01)	0.5	73.2	(1.7E-05, 6.3E-03, 2.5E-02)
Turkey Point 4	2	36	(1.0E-02, 5.6E-02, 1.6E-01)	0.8	32.4	(6.6E-04, 2.4E-02, 7.7E-02)
Vogtle 1	0	27	(0.0E+00, 0.0E+00, 1.1E-01)	0.4	76.3	(1.1E-05, 5.8E-03, 2.3E-02)
Vogtle 2	0	10	(0.0E+00, 0.0E+00, 2.6E-01)	0.5	69.3	(2.4E-05, 7.0E-03, 2.7E-02)
Waterford 3	0	19	(0.0E+00, 0.0E+00, 1.5E-01)	0.5	73.6	(1.7E-05, 6.3E-03, 2.5E-02)
Wolf Creek	0	11	(0.0E+00, 0.0E+00, 2.4E-01)	0.5	69.9	(2.3E-05, 6.9E-03, 2.7E-02)
Zion 1	0	1	(0.0E+00, 0.0E+00, 9.5E-01)	0.5	62.5	(2.9E-05, 7.8E-03, 3.0E-02)
Zion 2	0	0	—	0.6	70.4	(5.8E-05, 8.0E-03, 2.9E-02)
Population[c]	5	602	(3.3E-03, 8.3E-03, 1.7E-02)	0.6	70.4	(5.8E-05, 8.0E-03, 2.9E-02)

a. The middle number is the maximum likelihood estimate, *f/d*, and the end numbers form a 90% confidence interval.

b. The end numbers form a 90% uncertainty interval based on the empirical Bayes beta distribution. The middle number is the mean.

c. The confidence interval is too short, since it assumes no variation between plants.

Table E-4. Probability of failure to start from independent causes for motor trains, by plant.

Plant	Failures (*f*)	Demands (*d*)	Estimate (*f/d*) and C.I.[a]	Alpha	Beta	Bayes Mean and Interval
Arkansas 1	0	14	(0.0E+00, 0.0E+00, 1.9E-01)	0.1	48.9	(<1.0E-08, 2.7E-03, 1.5E-02)
Arkansas 2	0	9	(0.0E+00, 0.0E+00, 2.8E-01)	0.1	44.1	(<1.0E-08, 3.0E-03, 1.7E-02)
Beaver Valley 1	0	24	(0.0E+00, 0.0E+00, 1.2E-01)	0.1	58.4	(<1.0E-08, 2.3E-03, 1.3E-02)
Beaver Valley 2	0	43	(0.0E+00, 0.0E+00, 6.7E-02)	0.1	75.7	(<1.0E-08, 1.7E-03, 9.8E-03)
Braidwood 1	0	13	(0.0E+00, 0.0E+00, 2.1E-01)	0.1	48.0	(<1.0E-08, 2.8E-03, 1.6E-02)
Braidwood 2	0	24	(0.0E+00, 0.0E+00, 1.2E-01)	0.1	58.4	(<1.0E-08, 2.3E-03, 1.3E-02)
Byron 1	0	11	(0.0E+00, 0.0E+00, 2.4E-01)	0.1	46.0	(<1.0E-08, 2.9E-03, 1.6E-02)
Byron 2	0	16	(0.0E+00, 0.0E+00, 1.7E-01)	0.1	50.9	(<1.0E-08, 2.6E-03, 1.5E-02)
Callaway	0	57	(0.0E+00, 0.0E+00, 5.1E-02)	0.1	88.3	(<1.0E-08, 1.5E-03, 8.3E-03)
Calvert Cliffs 1	0	12	(0.0E+00, 0.0E+00, 2.2E-01)	0.1	47.0	(<1.0E-08, 2.8E-03, 1.6E-02)
Calvert Cliffs 2	0	15	(0.0E+00, 0.0E+00, 1.8E-01)	0.1	49.9	(<1.0E-08, 2.7E-03, 1.5E-02)
Catawba 1	0	41	(0.0E+00, 0.0E+00, 7.0E-02)	0.1	73.9	(<1.0E-08, 1.8E-03, 1.0E-02)
Catawba 2	0	89	(0.0E+00, 0.0E+00, 3.3E-02)	0.1	116.6	(<1.0E-08, 1.1E-03, 6.2E-03)
Comanche Peak 1	0	66	(0.0E+00, 0.0E+00, 4.4E-02)	0.1	96.3	(<1.0E-08, 1.3E-03, 7.6E-03)
Comanche Peak 2	0	14	(0.0E+00, 0.0E+00, 1.9E-01)	0.1	48.9	(<1.0E-08, 2.7E-03, 1.5E-02)
Cook 1	0	18	(0.0E+00, 0.0E+00, 1.5E-01)	0.1	52.8	(<1.0E-08, 2.5E-03, 1.4E-02)
Cook 2	0	36	(0.0E+00, 0.0E+00, 8.0E-02)	0.1	69.4	(<1.0E-08, 1.9E-03, 1.1E-02)
Crystal River 3	1	16	(3.2E-03, 6.3E-02, 2.6E-01)	0.7	29.9	(<1.0E-08, 2.2E-02, 7.4E-02)
Davis-Besse	0	0	—	—	—	—
Diablo Canyon 1	0	46	(0.0E+00, 0.0E+00, 6.3E-02)	0.1	78.4	(<1.0E-08, 1.7E-03, 9.4E-03)
Diablo Canyon 2	0	30	(0.0E+00, 0.0E+00, 9.5E-02)	0.1	63.9	(<1.0E-08, 2.1E-03, 1.2E-02)
Farley 1	0	34	(0.0E+00, 0.0E+00, 8.4E-02)	0.1	67.6	(<1.0E-08, 2.0E-03, 1.1E-02)
Farley 2	0	54	(0.0E+00, 0.0E+00, 5.4E-02)	0.1	85.6	(<1.0E-08, 1.5E-03, 8.6E-03)
Fort Calhoun	0	5	(0.0E+00, 0.0E+00, 4.5E-01)	0.1	40.0	(<1.0E-08, 3.3E-03, 1.9E-02)
Ginna	0	28	(0.0E+00, 0.0E+00, 1.0E-01)	0.1	62.1	(<1.0E-08, 2.1E-03, 1.2E-02)
Haddam Neck	0	0	—	—	—	—
Harris	0	98	(0.0E+00, 0.0E+00, 3.0E-02)	0.1	124.5	(<1.0E-08, 1.0E-03, 5.8E-03)
Indian Point 2	1	24	(2.1E-03, 4.2E-02, 1.8E-01)	0.8	39.3	(<1.0E-08, 1.9E-02, 6.2E-02)
Indian Point 3	2	32	(1.1E-02, 6.3E-02, 1.8E-01)	1.1	35.7	(<1.0E-08, 3.1E-02, 8.8E-02)
Kewaunee	0	26	(0.0E+00, 0.0E+00, 1.1E-01)	0.1	60.2	(<1.0E-08, 2.2E-03, 1.2E-02)
Maine Yankee	0	23	(0.0E+00, 0.0E+00, 1.2E-01)	0.1	57.5	(<1.0E-08, 2.3E-03, 1.3E-02)
Mcguire 1	0	45	(0.0E+00, 0.0E+00, 6.4E-02)	0.1	77.5	(<1.0E-08, 1.7E-03, 9.5E-03)
Mcguire 2	0	44	(0.0E+00, 0.0E+00, 6.6E-02)	0.1	76.6	(<1.0E-08, 1.7E-03, 9.7E-03)
Millstone 2	1	11	(4.7E-03, 9.1E-02, 3.6E-01)	0.6	24.3	(<1.0E-08, 2.4E-02, 8.5E-02)
Millstone 3	0	54	(0.0E+00, 0.0E+00, 5.4E-02)	0.1	85.6	(<1.0E-08, 1.5E-03, 8.6E-03)
North Anna 1	0	20	(0.0E+00, 0.0E+00, 1.4E-01)	0.1	54.6	(<1.0E-08, 2.4E-03, 1.4E-02)
North Anna 2	0	18	(0.0E+00, 0.0E+00, 1.5E-01)	0.1	52.8	(<1.0E-08, 2.5E-03, 1.4E-02)
Oconee 1	0	18	(0.0E+00, 0.0E+00, 1.5E-01)	0.1	52.8	(<1.0E-08, 2.5E-03, 1.4E-02)
Oconee 2	0	18	(0.0E+00, 0.0E+00, 1.5E-01)	0.1	52.8	(<1.0E-08, 2.5E-03, 1.4E-02)
Oconee 3	0	12	(0.0E+00, 0.0E+00, 2.2E-01)	0.1	47.0	(<1.0E-08, 2.8E-03, 1.6E-02)
Palisades	0	13	(0.0E+00, 0.0E+00, 2.1E-01)	0.1	48.0	(<1.0E-08, 2.8E-03, 1.6E-02)
Palo Verde 1	0	7	(0.0E+00, 0.0E+00, 3.5E-01)	0.1	42.1	(<1.0E-08, 3.2E-03, 1.8E-02)
Palo Verde 2	0	12	(0.0E+00, 0.0E+00, 2.2E-01)	0.1	47.0	(<1.0E-08, 2.8E-03, 1.6E-02)
Palo Verde 3	0	9	(0.0E+00, 0.0E+00, 2.8E-01)	0.1	44.1	(<1.0E-08, 3.0E-03, 1.7E-02)
Point Beach 1	0	8	(0.0E+00, 0.0E+00, 3.1E-01)	0.1	43.1	(<1.0E-08, 3.1E-03, 1.7E-02)
Point Beach 2	0	16	(0.0E+00, 0.0E+00, 1.7E-01)	0.1	50.9	(<1.0E-08, 2.6E-03, 1.5E-02)

Table E-4. (continued).

Plant	Failures (f)	Demands (d)	Estimate (f/d) and C.I.[a]	Alpha	Beta	Bayes Mean and Interval
Prairie Island 1	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	0.1	38.0	(<1.0E-08, 3.5E-03, 2.0E-02)
Prairie Island 2	0	7	(0.0E+00, 0.0E+00, 3.5E-01)	0.1	42.1	(<1.0E-08, 3.2E-03, 1.8E-02)
Robinson 2	1	28	(1.8E-03, 3.6E-02, 1.6E-01)	0.8	44.1	(<1.0E-08, 1.8E-02, 5.7E-02)
Salem 1	0	24	(0.0E+00, 0.0E+00, 1.2E-01)	0.1	58.4	(<1.0E-08, 2.3E-03, 1.3E-02)
Salem 2	0	32	(0.0E+00, 0.0E+00, 8.9E-02)	0.1	65.8	(<1.0E-08, 2.0E-03, 1.1E-02)
San Onofre 2	0	13	(0.0E+00, 0.0E+00, 2.1E-01)	0.1	48.0	(<1.0E-08, 2.8E-03, 1.6E-02)
San Onofre 3	0	17	(0.0E+00, 0.0E+00, 1.6E-01)	0.1	51.8	(<1.0E-08, 2.6E-03, 1.4E-02)
Seabrook	0	17	(0.0E+00, 0.0E+00, 1.6E-01)	0.1	51.8	(<1.0E-08, 2.6E-03, 1.4E-02)
Sequoyah 1	0	30	(0.0E+00, 0.0E+00, 9.5E-02)	0.1	63.9	(<1.0E-08, 2.1E-03, 1.2E-02)
Sequoyah 2	0	41	(0.0E+00, 0.0E+00, 7.0E-02)	0.1	73.9	(<1.0E-08, 1.8E-03, 1.0E-02)
South Texas 1	0	69	(0.0E+00, 0.0E+00, 4.2E-02)	0.1	98.9	(<1.0E-08, 1.3E-03, 7.4E-03)
South Texas 2	0	87	(0.0E+00, 0.0E+00, 3.4E-02)	0.1	114.8	(<1.0E-08, 1.1E-03, 6.3E-03)
St. Lucie 1	0	35	(0.0E+00, 0.0E+00, 8.2E-02)	0.1	68.5	(<1.0E-08, 1.9E-03, 1.1E-02)
St. Lucie 2	0	21	(0.0E+00, 0.0E+00, 1.3E-01)	0.1	55.6	(<1.0E-08, 2.4E-03, 1.3E-02)
Summer	0	24	(0.0E+00, 0.0E+00, 1.2E-01)	0.1	58.4	(<1.0E-08, 2.3E-03, 1.3E-02)
Surry 1	0	26	(0.0E+00, 0.0E+00, 1.1E-01)	0.1	60.2	(<1.0E-08, 2.2E-03, 1.2E-02)
Surry 2	0	32	(0.0E+00, 0.0E+00, 8.9E-02)	0.1	65.8	(<1.0E-08, 2.0E-03, 1.1E-02)
Three Mile Isl 1	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	0.1	41.1	(<1.0E-08, 3.2E-03, 1.8E-02)
Turkey Point 3	0	0	—	—	—	—
Turkey Point 4	0	0	—	—	—	—
Vogtle 1	0	103	(0.0E+00, 0.0E+00, 2.9E-02)	0.1	128.9	(<1.0E-08, 9.9E-04, 5.6E-03)
Vogtle 2	0	45	(0.0E+00, 0.0E+00, 6.4E-02)	0.1	77.5	(<1.0E-08, 1.7E-03, 9.5E-03)
Waterford 3	0	38	(0.0E+00, 0.0E+00, 7.6E-02)	0.1	71.2	(<1.0E-08, 1.8E-03, 1.0E-02)
Wolf Creek	0	51	(0.0E+00, 0.0E+00, 5.7E-02)	0.1	82.9	(<1.0E-08, 1.6E-03, 8.9E-03)
Zion 1	0	13	(0.0E+00, 0.0E+00, 2.1E-01)	0.1	48.0	(<1.0E-08, 2.8E-03, 1.6E-02)
Zion 2	0	8	(0.0E+00, 0.0E+00, 3.1E-01)	0.1	43.1	(<1.0E-08, 3.1E-03, 1.7E-02)
Population[c]	6	1993	(1.3E-03, 3.0E-03, 5.9E-03)	0.1	36.3	(<1.0E-08, 3.8E-03, 2.1E-02)

a. The middle number is the maximum likelihood estimate, f/d, and the end numbers form a 90% confidence interval.

b. The end numbers form a 90% uncertainty interval based on the empirical Bayes beta distribution. The middle number is the mean.

c. The confidence interval is too short, since it assumes no variation between plants.

Table E-5. Probability of failure to start from independent causes for turbine trains, by plant (risk-based model).

Plant	Failures (f)	Demands (d)	Estimate (f/d) and C.I.[a]	Alpha	Beta	Bayes Mean and Interval
Arkansas 1	0	12	(0.0E+00, 0.0E+00, 2.2E-01)	4.3	155.3	(9.9E-03, 2.7E-02, 5.1E-02)
Arkansas 2	1	10	(5.1E-03, 1.0E-01, 3.9E-01)	3.3	102.7	(9.4E-03, 3.1E-02, 6.3E-02)
Beaver Valley 1	0	16	(0.0E+00, 0.0E+00, 1.7E-01)	3.9	143.1	(9.2E-03, 2.7E-02, 5.2E-02)
Beaver Valley 2	1	27	(1.9E-03, 3.7E-02, 1.6E-01)	5.4	179.3	(1.2E-02, 2.9E-02, 5.2E-02)
Braidwood 1	0	0	—	—	—	—
Braidwood 2	0	0	—	—	—	—
Byron 1	0	0	—	—	—	—
Byron 2	0	0	—	—	—	—
Callaway	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	4.9	170.5	(1.1E-02, 2.8E-02, 5.1E-02)
Calvert Cliffs 1	1	10	(5.1E-03, 1.0E-01, 3.9E-01)	3.3	102.7	(9.4E-03, 3.1E-02, 6.3E-02)
Calvert Cliffs 2	0	11	(0.0E+00, 0.0E+00, 2.4E-01)	4.4	158.0	(1.0E-02, 2.7E-02, 5.1E-02)
Catawba 1	0	4	(0.0E+00, 0.0E+00, 5.3E-01)	4.9	170.1	(1.1E-02, 2.8E-02, 5.1E-02)
Catawba 2	1	32	(1.6E-03, 3.1E-02, 1.4E-01)	5.8	194.7	(1.2E-02, 2.9E-02, 5.1E-02)
Comanche Peak 1	1	8	(6.4E-03, 1.3E-01, 4.7E-01)	3.1	94.5	(8.9E-03, 3.1E-02, 6.5E-02)
Comanche Peak 2	0	1	(0.0E+00, 0.0E+00, 9.5E-01)	5.0	169.9	(1.1E-02, 2.8E-02, 5.2E-02)
Cook 1	0	5	(0.0E+00, 0.0E+00, 4.5E-01)	4.9	169.4	(1.1E-02, 2.8E-02, 5.1E-02)
Cook 2	1	9	(5.7E-03, 1.1E-01, 4.3E-01)	3.2	98.5	(9.2E-03, 3.1E-02, 6.4E-02)
Crystal River 3	1	16	(3.2E-03, 6.3E-02, 2.6E-01)	4.1	129.5	(1.1E-02, 3.1E-02, 5.8E-02)
Davis-Besse	0	8	(0.0E+00, 0.0E+00, 3.1E-01)	4.7	165.0	(1.1E-02, 2.8E-02, 5.1E-02)
Diablo Canyon 1	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	4.8	168.2	(1.1E-02, 2.8E-02, 5.1E-02)
Diablo Canyon 2	0	1	(0.0E+00, 0.0E+00, 9.5E-01)	5.0	169.9	(1.1E-02, 2.8E-02, 5.2E-02)
Farley 1	0	5	(0.0E+00, 0.0E+00, 4.5E-01)	4.9	169.4	(1.1E-02, 2.8E-02, 5.1E-02)
Farley 2	0	1	(0.0E+00, 0.0E+00, 9.5E-01)	5.0	169.9	(1.1E-02, 2.8E-02, 5.2E-02)
Fort Calhoun	0	2	(0.0E+00, 0.0E+00, 7.8E-01)	5.0	170.4	(1.1E-02, 2.8E-02, 5.1E-02)
Ginna	0	8	(0.0E+00, 0.0E+00, 3.1E-01)	4.7	165.0	(1.1E-02, 2.8E-02, 5.1E-02)
Haddam Neck	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	4.8	168.2	(1.1E-02, 2.8E-02, 5.1E-02)
Harris	3	14	(6.1E-02, 2.1E-01, 4.7E-01)	0.8	20.9	(1.2E-03, 3.8E-02, 1.2E-01)
Indian Point 2	0	1	(0.0E+00, 0.0E+00, 9.5E-01)	5.0	169.9	(1.1E-02, 2.8E-02, 5.2E-02)
Indian Point 3	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	4.8	168.2	(1.1E-02, 2.8E-02, 5.1E-02)
Kewaunee	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	4.9	170.5	(1.1E-02, 2.8E-02, 5.1E-02)
Maine Yankee	0	0	—	7.2	245.3	(1.4E-02, 2.9E-02, 4.8E-02)
Mcguire 1	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	4.8	168.2	(1.1E-02, 2.8E-02, 5.1E-02)
Mcguire 2	0	4	(0.0E+00, 0.0E+00, 5.3E-01)	4.9	170.1	(1.1E-02, 2.8E-02, 5.1E-02)
Millstone 2	0	0	—	7.2	245.3	(1.4E-02, 2.9E-02, 4.8E-02)
Millstone 3	0	8	(0.0E+00, 0.0E+00, 3.1E-01)	4.7	165.0	(1.1E-02, 2.8E-02, 5.1E-02)
North Anna 1	0	10	(0.0E+00, 0.0E+00, 2.6E-01)	4.5	160.6	(1.0E-02, 2.7E-02, 5.1E-02)
North Anna 2	0	9	(0.0E+00, 0.0E+00, 2.8E-01)	4.6	162.9	(1.0E-02, 2.8E-02, 5.1E-02)
Oconee 1	0	5	(0.0E+00, 0.0E+00, 4.5E-01)	4.9	169.4	(1.1E-02, 2.8E-02, 5.1E-02)
Oconee 2	0	7	(0.0E+00, 0.0E+00, 3.5E-01)	4.8	166.8	(1.1E-02, 2.8E-02, 5.1E-02)
Oconee 3	0	7	(0.0E+00, 0.0E+00, 3.5E-01)	4.8	166.8	(1.1E-02, 2.8E-02, 5.1E-02)
Palisades	0	1	(0.0E+00, 0.0E+00, 9.5E-01)	5.0	169.9	(1.1E-02, 2.8E-02, 5.2E-02)
Palo Verde 1	0	0	—	7.2	245.3	(1.4E-02, 2.9E-02, 4.8E-02)
Palo Verde 2	0	4	(0.0E+00, 0.0E+00, 5.3E-01)	4.9	170.1	(1.1E-02, 2.8E-02, 5.1E-02)
Palo Verde 3	0	2	(0.0E+00, 0.0E+00, 7.8E-01)	5.0	170.4	(1.1E-02, 2.8E-02, 5.1E-02)
Point Beach 1	0	0	—	7.2	245.3	(1.4E-02, 2.9E-02, 4.8E-02)

Table E-5. (continued).

Plant	Failures (f)	Demands (d)	Estimate (f/d) and C.I.[a]	Alpha	Beta	Bayes Mean and Interval
Point Beach 2	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	4.9	170.5	(1.1E-02, 2.8E-02, 5.1E-02)
Prairie Island 1	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	4.9	170.5	(1.1E-02, 2.8E-02, 5.1E-02)
Prairie Island 2	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	4.8	168.2	(1.1E-02, 2.8E-02, 5.1E-02)
Robinson 2	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	4.9	170.5	(1.1E-02, 2.8E-02, 5.1E-02)
Salem 1	0	4	(0.0E+00, 0.0E+00, 5.3E-01)	4.9	170.1	(1.1E-02, 2.8E-02, 5.1E-02)
Salem 2	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	4.8	168.2	(1.1E-02, 2.8E-02, 5.1E-02)
San Onofre 2	0	7	(0.0E+00, 0.0E+00, 3.5E-01)	4.8	166.8	(1.1E-02, 2.8E-02, 5.1E-02)
San Onofre 3	0	9	(0.0E+00, 0.0E+00, 2.8E-01)	4.6	162.9	(1.0E-02, 2.8E-02, 5.1E-02)
Seabrook	0	17	(0.0E+00, 0.0E+00, 1.6E-01)	3.8	139.9	(9.0E-03, 2.7E-02, 5.2E-02)
Sequoyah 1	0	14	(0.0E+00, 0.0E+00, 1.9E-01)	4.1	149.4	(9.6E-03, 2.7E-02, 5.1E-02)
Sequoyah 2	0	20	(0.0E+00, 0.0E+00, 1.4E-01)	3.5	130.3	(8.3E-03, 2.6E-02, 5.2E-02)
South Texas 1	0	23	(0.0E+00, 0.0E+00, 1.2E-01)	3.2	120.8	(7.7E-03, 2.6E-02, 5.3E-02)
South Texas 2	1	29	(1.8E-03, 3.4E-02, 1.5E-01)	5.6	186.3	(1.2E-02, 2.9E-02, 5.1E-02)
St. Lucie 1	0	15	(0.0E+00, 0.0E+00, 1.8E-01)	4.0	146.3	(9.4E-03, 2.7E-02, 5.2E-02)
St. Lucie 2	2	10	(3.7E-02, 2.0E-01, 5.1E-01)	1.4	37.6	(3.6E-03, 3.5E-02, 9.3E-02)
Summer	0	7	(0.0E+00, 0.0E+00, 3.5E-01)	4.8	166.8	(1.1E-02, 2.8E-02, 5.1E-02)
Surry 1	1	6	(8.5E-03, 1.7E-01, 5.8E-01)	2.8	86.9	(8.4E-03, 3.2E-02, 6.7E-02)
Surry 2	0	4	(0.0E+00, 0.0E+00, 5.3E-01)	4.9	170.1	(1.1E-02, 2.8E-02, 5.1E-02)
Three Mile Isl 1	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	4.9	170.5	(1.1E-02, 2.8E-02, 5.1E-02)
Turkey Point 3	0	18	(0.0E+00, 0.0E+00, 1.5E-01)	3.7	136.7	(8.8E-03, 2.7E-02, 5.2E-02)
Turkey Point 4	0	34	(0.0E+00, 0.0E+00, 8.4E-02)	2.4	91.3	(5.5E-03, 2.5E-02, 5.6E-02)
Vogtle 1	1	27	(1.9E-03, 3.7E-02, 1.6E-01)	5.4	179.3	(1.2E-02, 2.9E-02, 5.2E-02)
Vogtle 2	0	10	(0.0E+00, 0.0E+00, 2.6E-01)	4.5	160.6	(1.0E-02, 2.7E-02, 5.1E-02)
Waterford 3	1	19	(2.7E-03, 5.3E-02, 2.3E-01)	4.5	143.8	(1.1E-02, 3.0E-02, 5.6E-02)
Wolf Creek	1	11	(4.7E-03, 9.1E-02, 3.6E-01)	3.4	106.9	(9.6E-03, 3.1E-02, 6.2E-02)
Zion 1	0	1	(0.0E+00, 0.0E+00, 9.5E-01)	5.0	169.9	(1.1E-02, 2.8E-02, 5.2E-02)
Zion 2	0	0	—	7.2	245.3	(1.4E-02, 2.9E-02, 4.8E-02)
Population[c]	17	597	(1.8E-02, 2.8E-02, 4.2E-02)	7.2	245.3	(1.4E-02, 2.9E-02, 4.8E-02)

a. The middle number is the maximum likelihood estimate, *f/d*, and the end numbers form a 90% confidence interval.

b. The end numbers form a 90% uncertainty interval based on the empirical Bayes beta distribution. The middle number is the mean.

c. The confidence interval is too short, since it assumes no variation between plants.

Table E-6. Probability of failure to start from independent causes for turbine trains, by plant (operational model).

Plant	Failures (f)	Demands (d)	Estimate (f/d) and C.I.[a]	Alpha	Beta	Bayes Mean and Interval
Arkansas 1	0	12	(0.0E+00, 0.0E+00, 2.2E-01)	3.0	116.3	(6.8E-03, 2.5E-02, 5.2E-02)
Arkansas 2	1	10	(5.1E-03, 1.0E-01, 3.9E-01)	2.6	80.4	(7.5E-03, 3.1E-02, 6.7E-02)
Beaver Valley 1	0	16	(0.0E+00, 0.0E+00, 1.7E-01)	2.8	111.0	(6.2E-03, 2.4E-02, 5.2E-02)
Beaver Valley 2	1	27	(1.9E-03, 3.7E-02, 1.6E-01)	3.9	133.5	(9.6E-03, 2.8E-02, 5.5E-02)
Braidwood 1	0	0	—	—	—	—
Braidwood 2	0	0	—	—	—	—
Byron 1	0	0	—	—	—	—
Byron 2	0	0	—	—	—	—
Callaway	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	3.3	120.7	(7.8E-03, 2.6E-02, 5.3E-02)
Calvert Cliffs 1	1	10	(5.1E-03, 1.0E-01, 3.9E-01)	2.6	80.4	(7.5E-03, 3.1E-02, 6.7E-02)
Calvert Cliffs 2	0	11	(0.0E+00, 0.0E+00, 2.4E-01)	3.0	117.4	(6.9E-03, 2.5E-02, 5.2E-02)
Catawba 1	0	4	(0.0E+00, 0.0E+00, 5.3E-01)	3.2	121.0	(7.7E-03, 2.6E-02, 5.3E-02)
Catawba 2	1	32	(1.6E-03, 3.1E-02, 1.4E-01)	4.1	145.2	(9.7E-03, 2.8E-02, 5.3E-02)
Comanche Peak 1	1	8	(6.4E-03, 1.3E-01, 4.7E-01)	2.4	74.4	(7.1E-03, 3.2E-02, 7.0E-02)
Comanche Peak 2	0	1	(0.0E+00, 0.0E+00, 9.5E-01)	3.3	119.5	(7.9E-03, 2.7E-02, 5.4E-02)
Cook 1	0	5	(0.0E+00, 0.0E+00, 4.5E-01)	3.2	121.0	(7.6E-03, 2.6E-02, 5.3E-02)
Cook 2	1	9	(5.7E-03, 1.1E-01, 4.3E-01)	2.5	77.4	(7.3E-03, 3.1E-02, 6.8E-02)
Crystal River 3	1	16	(3.2E-03, 6.3E-02, 2.6E-01)	3.1	99.5	(8.5E-03, 3.0E-02, 6.2E-02)
Davis-Besse	0	8	(0.0E+00, 0.0E+00, 3.1E-01)	3.1	119.9	(7.3E-03, 2.5E-02, 5.2E-02)
Diablo Canyon 1	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	3.2	120.8	(7.5E-03, 2.6E-02, 5.3E-02)
Diablo Canyon 2	0	1	(0.0E+00, 0.0E+00, 9.5E-01)	3.3	119.5	(7.9E-03, 2.7E-02, 5.4E-02)
Farley 1	0	5	(0.0E+00, 0.0E+00, 4.5E-01)	3.2	121.0	(7.6E-03, 2.6E-02, 5.3E-02)
Farley 2	0	1	(0.0E+00, 0.0E+00, 9.5E-01)	3.3	119.5	(7.9E-03, 2.7E-02, 5.4E-02)
Fort Calhoun	0	2	(0.0E+00, 0.0E+00, 7.8E-01)	3.3	120.2	(7.9E-03, 2.6E-02, 5.4E-02)
Ginna	0	8	(0.0E+00, 0.0E+00, 3.1E-01)	3.1	119.9	(7.3E-03, 2.5E-02, 5.2E-02)
Haddam Neck	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	3.2	120.8	(7.5E-03, 2.6E-02, 5.3E-02)
Harris	3	14	(6.1E-02, 2.1E-01, 4.7E-01)	0.9	20.6	(1.7E-03, 4.2E-02, 1.3E-01)
Indian Point 2	0	1	(0.0E+00, 0.0E+00, 9.5E-01)	3.3	119.5	(7.9E-03, 2.7E-02, 5.4E-02)
Indian Point 3	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	3.2	120.8	(7.5E-03, 2.6E-02, 5.3E-02)
Kewaunee	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	3.3	120.7	(7.8E-03, 2.6E-02, 5.3E-02)
Maine Yankee	0	0	—	4.2	153.1	(9.6E-03, 2.7E-02, 5.1E-02)
Mcguire 1	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	3.2	120.8	(7.5E-03, 2.6E-02, 5.3E-02)
Mcguire 2	0	4	(0.0E+00, 0.0E+00, 5.3E-01)	3.2	121.0	(7.7E-03, 2.6E-02, 5.3E-02)
Millstone 2	0	0	—	4.2	153.1	(9.6E-03, 2.7E-02, 5.1E-02)
Millstone 3	0	8	(0.0E+00, 0.0E+00, 3.1E-01)	3.1	119.9	(7.3E-03, 2.5E-02, 5.2E-02)
North Anna 1	0	10	(0.0E+00, 0.0E+00, 2.6E-01)	3.1	118.4	(7.1E-03, 2.5E-02, 5.2E-02)
North Anna 2	0	9	(0.0E+00, 0.0E+00, 2.8E-01)	3.1	119.2	(7.2E-03, 2.5E-02, 5.2E-02)
Oconee 1	0	5	(0.0E+00, 0.0E+00, 4.5E-01)	3.2	121.0	(7.6E-03, 2.6E-02, 5.3E-02)
Oconee 2	0	7	(0.0E+00, 0.0E+00, 3.5E-01)	3.2	120.5	(7.4E-03, 2.6E-02, 5.2E-02)
Oconee 3	0	7	(0.0E+00, 0.0E+00, 3.5E-01)	3.2	120.5	(7.4E-03, 2.6E-02, 5.2E-02)
Palisades	0	1	(0.0E+00, 0.0E+00, 9.5E-01)	3.3	119.5	(7.9E-03, 2.7E-02, 5.4E-02)
Palo Verde 1	0	0	—	4.2	153.1	(9.6E-03, 2.7E-02, 5.1E-02)
Palo Verde 2	0	4	(0.0E+00, 0.0E+00, 5.3E-01)	3.2	121.0	(7.7E-03, 2.6E-02, 5.3E-02)
Palo Verde 3	0	2	(0.0E+00, 0.0E+00, 7.8E-01)	3.3	120.2	(7.9E-03, 2.6E-02, 5.4E-02)
Point Beach 1	0	0	—	4.2	153.1	(9.6E-03, 2.7E-02, 5.1E-02)

Table E-6. (continued).

Plant	Failures (f)	Demands (d)	Estimate (f/d) and C.I.[a]	Alpha	Beta	Bayes Mean and Interval
Point Beach 2	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	3.3	120.7	(7.8E-03, 2.6E-02, 5.3E-02)
Prairie Island 1	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	3.3	120.7	(7.8E-03, 2.6E-02, 5.3E-02)
Prairie Island 2	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	3.2	120.8	(7.5E-03, 2.6E-02, 5.3E-02)
Robinson 2	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	3.3	120.7	(7.8E-03, 2.6E-02, 5.3E-02)
Salem 1	0	4	(0.0E+00, 0.0E+00, 5.3E-01)	3.2	121.0	(7.7E-03, 2.6E-02, 5.3E-02)
Salem 2	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	3.2	120.8	(7.5E-03, 2.6E-02, 5.3E-02)
San Onofre 2	0	7	(0.0E+00, 0.0E+00, 3.5E-01)	3.2	120.5	(7.4E-03, 2.6E-02, 5.2E-02)
San Onofre 3	0	9	(0.0E+00, 0.0E+00, 2.8E-01)	3.1	119.2	(7.2E-03, 2.5E-02, 5.2E-02)
Seabrook	0	17	(0.0E+00, 0.0E+00, 1.6E-01)	2.7	109.6	(6.1E-03, 2.4E-02, 5.2E-02)
Sequoyah 1	0	14	(0.0E+00, 0.0E+00, 1.9E-01)	2.9	113.8	(6.5E-03, 2.5E-02, 5.2E-02)
Sequoyah 2	0	20	(0.0E+00, 0.0E+00, 1.4E-01)	2.6	104.9	(5.6E-03, 2.4E-02, 5.2E-02)
South Texas 1	0	23	(0.0E+00, 0.0E+00, 1.2E-01)	2.4	100.2	(5.2E-03, 2.3E-02, 5.2E-02)
South Texas 2	1	29	(1.8E-03, 3.4E-02, 1.5E-01)	4.0	138.6	(9.7E-03, 2.8E-02, 5.4E-02)
St. Lucie 1	0	15	(0.0E+00, 0.0E+00, 1.8E-01)	2.8	112.5	(6.4E-03, 2.4E-02, 5.2E-02)
St. Lucie 2	2	10	(3.7E-02, 2.0E-01, 5.1E-01)	1.3	33.9	(3.5E-03, 3.7E-02, 1.0E-01)
Summer	0	7	(0.0E+00, 0.0E+00, 3.5E-01)	3.2	120.5	(7.4E-03, 2.6E-02, 5.2E-02)
Surry 1	1	6	(8.5E-03, 1.7E-01, 5.8E-01)	2.3	68.7	(6.7E-03, 3.2E-02, 7.2E-02)
Surry 2	0	4	(0.0E+00, 0.0E+00, 5.3E-01)	3.2	121.0	(7.7E-03, 2.6E-02, 5.3E-02)
Three Mile Isl 1	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	3.3	120.7	(7.8E-03, 2.6E-02, 5.3E-02)
Turkey Point 3	0	18	(0.0E+00, 0.0E+00, 1.5E-01)	2.7	108.0	(5.9E-03, 2.4E-02, 5.2E-02)
Turkey Point 4	0	34	(0.0E+00, 0.0E+00, 8.4E-02)	1.9	83.8	(3.7E-03, 2.2E-02, 5.3E-02)
Vogtle 1	1	27	(1.9E-03, 3.7E-02, 1.6E-01)	3.9	133.5	(9.6E-03, 2.8E-02, 5.5E-02)
Vogtle 2	0	10	(0.0E+00, 0.0E+00, 2.6E-01)	3.1	118.4	(7.1E-03, 2.5E-02, 5.2E-02)
Waterford 3	1	19	(2.7E-03, 5.3E-02, 2.3E-01)	3.3	109.3	(8.9E-03, 3.0E-02, 6.0E-02)
Wolf Creek	0	11	(0.0E+00, 0.0E+00, 2.4E-01)	3.0	117.4	(6.9E-03, 2.5E-02, 5.2E-02)
Zion 1	0	1	(0.0E+00, 0.0E+00, 9.5E-01)	3.3	119.5	(7.9E-03, 2.7E-02, 5.4E-02)
Zion 2	0	0	—	4.2	153.1	(9.6E-03, 2.7E-02, 5.1E-02)
Population[c]	16	597	(1.7E-02, 2.7E-02, 4.0E-02)	4.2	153.1	(9.6E-03, 2.7E-02, 5.1E-02)

a. The middle number is the maximum likelihood estimate, *f/d*, and the end numbers form a 90% confidence interval.

b. The end numbers form a 90% uncertainty interval based on the empirical Bayes beta distribution. The middle number is the mean.

c. The confidence interval is too short, since it assumes no variation between plants.

Table E-7. Probability of failure to start from all causes for motor trains, by plant.

Plant	Failures (f)	Demands (d)	Estimate (*f/d*) and C.I.[a]	Alpha	Beta	Bayes Mean and Interval
Arkansas 1	0	14	(0.0E+00, 0.0E+00, 1.9E-01)	0.1	27.7	(<1.0E-08, 3.2E-03, 1.9E-02)
Arkansas 2	0	9	(0.0E+00, 0.0E+00, 2.8E-01)	0.1	22.8	(<1.0E-08, 3.9E-03, 2.3E-02)
Beaver Valley 1	0	24	(0.0E+00, 0.0E+00, 1.2E-01)	0.1	37.4	(<1.0E-08, 2.3E-03, 1.4E-02)
Beaver Valley 2	0	43	(0.0E+00, 0.0E+00, 6.7E-02)	0.1	55.7	(<1.0E-08, 1.6E-03, 9.2E-03)
Braidwood 1	0	13	(0.0E+00, 0.0E+00, 2.1E-01)	0.1	26.7	(<1.0E-08, 3.3E-03, 1.9E-02)
Braidwood 2	0	24	(0.0E+00, 0.0E+00, 1.2E-01)	0.1	37.4	(<1.0E-08, 2.3E-03, 1.4E-02)
Byron 1	0	11	(0.0E+00, 0.0E+00, 2.4E-01)	0.1	24.8	(<1.0E-08, 3.6E-03, 2.1E-02)
Byron 2	0	16	(0.0E+00, 0.0E+00, 1.7E-01)	0.1	29.7	(<1.0E-08, 3.0E-03, 1.7E-02)
Callaway	0	57	(0.0E+00, 0.0E+00, 5.1E-02)	0.1	69.2	(<1.0E-08, 1.3E-03, 7.4E-03)
Calvert Cliffs 1	0	12	(0.0E+00, 0.0E+00, 2.2E-01)	0.1	25.8	(<1.0E-08, 3.4E-03, 2.0E-02)
Calvert Cliffs 2	0	15	(0.0E+00, 0.0E+00, 1.8E-01)	0.1	28.7	(<1.0E-08, 3.1E-03, 1.8E-02)
Catawba 1	0	41	(0.0E+00, 0.0E+00, 7.0E-02)	0.1	53.8	(<1.0E-08, 1.6E-03, 9.5E-03)
Catawba 2	0	89	(0.0E+00, 0.0E+00, 3.3E-02)	0.1	100.0	(<1.0E-08, 8.7E-04, 5.1E-03)
Comanche Peak 1	0	66	(0.0E+00, 0.0E+00, 4.4E-02)	0.1	77.9	(<1.0E-08, 1.1E-03, 6.5E-03)
Comanche Peak 2	0	14	(0.0E+00, 0.0E+00, 1.9E-01)	0.1	27.7	(<1.0E-08, 3.2E-03, 1.9E-02)
Cook 1	0	18	(0.0E+00, 0.0E+00, 1.5E-01)	0.1	31.6	(<1.0E-08, 2.8E-03, 1.6E-02)
Cook 2	0	36	(0.0E+00, 0.0E+00, 8.0E-02)	0.1	49.0	(<1.0E-08, 1.8E-03, 1.0E-02)
Crystal River 3	1	16	(3.2E-03, 6.3E-02, 2.6E-01)	0.9	25.2	(<1.0E-08, 3.6E-02, 1.1E-01)
Davis-Besse	0	0	—	0.1	14.2	(<1.0E-08, 6.3E-03, 3.7E-02)
Diablo Canyon 1	0	46	(0.0E+00, 0.0E+00, 6.3E-02)	0.1	58.6	(<1.0E-08, 1.5E-03, 8.7E-03)
Diablo Canyon 2	0	30	(0.0E+00, 0.0E+00, 9.5E-02)	0.1	43.2	(<1.0E-08, 2.0E-03, 1.2E-02)
Farley 1	2	34	(1.1E-02, 5.9E-02, 1.7E-01)	1.9	41.2	(<1.0E-08, 4.3E-02, 1.0E-01)
Farley 2	0	54	(0.0E+00, 0.0E+00, 5.4E-02)	0.1	66.3	(<1.0E-08, 1.3E-03, 7.7E-03)
Fort Calhoun	0	5	(0.0E+00, 0.0E+00, 4.5E-01)	0.1	18.9	(<1.0E-08, 4.7E-03, 2.8E-02)
Ginna	0	28	(0.0E+00, 0.0E+00, 1.0E-01)	0.1	41.3	(<1.0E-08, 2.1E-03, 1.2E-02)
Haddam Neck	0	0	—	0.1	14.2	(<1.0E-08, 6.3E-03, 3.7E-02)
Harris	0	98	(0.0E+00, 0.0E+00, 3.0E-02)	0.1	108.6	(<1.0E-08, 8.0E-04, 4.7E-03)
Indian Point 2	3	24	(3.5E-02, 1.3E-01, 2.9E-01)	2.3	26.5	(<1.0E-08, 8.1E-02, 1.8E-01)
Indian Point 3	2	32	(1.1E-02, 6.3E-02, 1.8E-01)	1.8	39.0	(<1.0E-08, 4.5E-02, 1.1E-01)
Kewaunee	0	26	(0.0E+00, 0.0E+00, 1.1E-01)	0.1	39.3	(<1.0E-08, 2.2E-03, 1.3E-02)
Maine Yankee	0	23	(0.0E+00, 0.0E+00, 1.2E-01)	0.1	36.4	(<1.0E-08, 2.4E-03, 1.4E-02)
Mcguire 1	0	45	(0.0E+00, 0.0E+00, 6.4E-02)	0.1	57.7	(<1.0E-08, 1.5E-03, 8.9E-03)
Mcguire 2	0	44	(0.0E+00, 0.0E+00, 6.6E-02)	0.1	56.7	(<1.0E-08, 1.5E-03, 9.0E-03)
Millstone 2	1	11	(4.7E-03, 9.1E-02, 3.6E-01)	0.9	19.5	(<1.0E-08, 4.3E-02, 1.3E-01)
Millstone 3	0	54	(0.0E+00, 0.0E+00, 5.4E-02)	0.1	66.3	(<1.0E-08, 1.3E-03, 7.7E-03)
North Anna 1	0	20	(0.0E+00, 0.0E+00, 1.4E-01)	0.1	33.5	(<1.0E-08, 2.6E-03, 1.5E-02)
North Anna 2	0	18	(0.0E+00, 0.0E+00, 1.5E-01)	0.1	31.6	(<1.0E-08, 2.8E-03, 1.6E-02)
Oconee 1	0	18	(0.0E+00, 0.0E+00, 1.5E-01)	0.1	31.6	(<1.0E-08, 2.8E-03, 1.6E-02)
Oconee 2	0	18	(0.0E+00, 0.0E+00, 1.5E-01)	0.1	31.6	(<1.0E-08, 2.8E-03, 1.6E-02)
Oconee 3	0	12	(0.0E+00, 0.0E+00, 2.2E-01)	0.1	25.8	(<1.0E-08, 3.4E-03, 2.0E-02)
Palisades	0	13	(0.0E+00, 0.0E+00, 2.1E-01)	0.1	26.7	(<1.0E-08, 3.3E-03, 1.9E-02)
Palo Verde 1	0	7	(0.0E+00, 0.0E+00, 3.5E-01)	0.1	20.8	(<1.0E-08, 4.2E-03, 2.5E-02)
Palo Verde 2	0	12	(0.0E+00, 0.0E+00, 2.2E-01)	0.1	25.8	(<1.0E-08, 3.4E-03, 2.0E-02)
Palo Verde 3	0	9	(0.0E+00, 0.0E+00, 2.8E-01)	0.1	22.8	(<1.0E-08, 3.9E-03, 2.3E-02)
Point Beach 1	0	8	(0.0E+00, 0.0E+00, 3.1E-01)	0.1	21.8	(<1.0E-08, 4.0E-03, 2.4E-02)
Point Beach 2	0	16	(0.0E+00, 0.0E+00, 1.7E-01)	0.1	29.7	(<1.0E-08, 3.0E-03, 1.7E-02)

Table E-7. (continued).

Plant	Failures (f)	Demands (d)	Estimate (f/d) and C.I.[a]	Alpha	Beta	Bayes Mean and Interval
Prairie Island 1	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	0.1	16.9	(<1.0E-08, 5.2E-03, 3.1E-02)
Prairie Island 2	0	7	(0.0E+00, 0.0E+00, 3.5E-01)	0.1	20.8	(<1.0E-08, 4.2E-03, 2.5E-02)
Robinson 2	1	28	(1.8E-03, 3.6E-02, 1.6E-01)	1.0	38.5	(<1.0E-08, 2.6E-02, 7.6E-02)
Salem 1	0	24	(0.0E+00, 0.0E+00, 1.2E-01)	0.1	37.4	(<1.0E-08, 2.3E-03, 1.4E-02)
Salem 2	0	32	(0.0E+00, 0.0E+00, 8.9E-02)	0.1	45.1	(<1.0E-08, 1.9E-03, 1.1E-02)
San Onofre 2	0	13	(0.0E+00, 0.0E+00, 2.1E-01)	0.1	26.7	(<1.0E-08, 3.3E-03, 1.9E-02)
San Onofre 3	0	17	(0.0E+00, 0.0E+00, 1.6E-01)	0.1	30.6	(<1.0E-08, 2.9E-03, 1.7E-02)
Seabrook	0	17	(0.0E+00, 0.0E+00, 1.6E-01)	0.1	30.6	(<1.0E-08, 2.9E-03, 1.7E-02)
Sequoyah 1	0	30	(0.0E+00, 0.0E+00, 9.5E-02)	0.1	43.2	(<1.0E-08, 2.0E-03, 1.2E-02)
Sequoyah 2	0	41	(0.0E+00, 0.0E+00, 7.0E-02)	0.1	53.8	(<1.0E-08, 1.6E-03, 9.5E-03)
South Texas 1	0	69	(0.0E+00, 0.0E+00, 4.2E-02)	0.1	80.8	(<1.0E-08, 1.1E-03, 6.3E-03)
South Texas 2	0	87	(0.0E+00, 0.0E+00, 3.4E-02)	0.1	98.1	(<1.0E-08, 8.9E-04, 5.2E-03)
St. Lucie 1	0	35	(0.0E+00, 0.0E+00, 8.2E-02)	0.1	48.0	(<1.0E-08, 1.8E-03, 1.1E-02)
St. Lucie 2	0	21	(0.0E+00, 0.0E+00, 1.3E-01)	0.1	34.5	(<1.0E-08, 2.5E-03, 1.5E-02)
Summer	0	24	(0.0E+00, 0.0E+00, 1.2E-01)	0.1	37.4	(<1.0E-08, 2.3E-03, 1.4E-02)
Surry 1	0	26	(0.0E+00, 0.0E+00, 1.1E-01)	0.1	39.3	(<1.0E-08, 2.2E-03, 1.3E-02)
Surry 2	0	32	(0.0E+00, 0.0E+00, 8.9E-02)	0.1	45.1	(<1.0E-08, 1.9E-03, 1.1E-02)
Three Mile Isl 1	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	0.1	19.9	(<1.0E-08, 4.4E-03, 2.6E-02)
Turkey Point 3	0	0	—	0.1	14.2	(<1.0E-08, 6.3E-03, 3.7E-02)
Turkey Point 4	0	0	—	0.1	14.2	(<1.0E-08, 6.3E-03, 3.7E-02)
Vogtle 1	0	103	(0.0E+00, 0.0E+00, 2.9E-02)	0.1	113.4	(<1.0E-08, 7.7E-04, 4.5E-03)
Vogtle 2	0	45	(0.0E+00, 0.0E+00, 6.4E-02)	0.1	57.7	(<1.0E-08, 1.5E-03, 8.9E-03)
Waterford 3	0	38	(0.0E+00, 0.0E+00, 7.6E-02)	0.1	50.9	(<1.0E-08, 1.7E-03, 1.0E-02)
Wolf Creek	0	51	(0.0E+00, 0.0E+00, 5.7E-02)	0.1	63.4	(<1.0E-08, 1.4E-03, 8.1E-03)
Zion 1	0	13	(0.0E+00, 0.0E+00, 2.1E-01)	0.1	26.7	(<1.0E-08, 3.3E-03, 1.9E-02)
Zion 2	0	8	(0.0E+00, 0.0E+00, 3.1E-01)	0.1	21.8	(<1.0E-08, 4.0E-03, 2.4E-02)
Population[c]	10	1993	(2.7E-03, 5.0E-03, 8.5E-03)	0.1	14.2	(<1.0E-08, 6.3E-03, 3.7E-02)

a. The middle number is the maximum likelihood estimate, *f/d*, and the end numbers form a 90% confidence interval.

b. The end numbers form a 90% uncertainty interval based on the empirical Bayes beta distribution. The middle number is the mean.

c. The confidence interval is too short, since it assumes no variation between plants.

Table E-8. Probability of failure of feed control segments from independent causes, by plant.

Plant	Failures (*f*)	Demands (*d*)	Estimate (*f/d*) and C.I.[a]	Alpha	Beta	Bayes Mean and Interval
Arkansas 1	0	49	(0.0E+00, 0.0E+00, 5.9E-02)	0.4	140.9	(3.2E-06, 2.9E-03, 1.2E-02)
Arkansas 2	0	33	(0.0E+00, 0.0E+00, 8.7E-02)	0.4	126.0	(3.7E-06, 3.2E-03, 1.3E-02)
Beaver Valley 1	0	96	(0.0E+00, 0.0E+00, 3.1E-02)	0.4	183.1	(2.2E-06, 2.2E-03, 9.0E-03)
Beaver Valley 2	1	153	(3.4E-04, 6.5E-03, 3.1E-02)	1.4	242.4	(5.8E-04, 5.7E-03, 1.5E-02)
Braidwood 1	0	108	(0.0E+00, 0.0E+00, 2.7E-02)	0.4	193.6	(2.0E-06, 2.0E-03, 8.5E-03)
Braidwood 2	1	192	(2.7E-04, 5.2E-03, 2.4E-02)	1.4	283.3	(5.1E-04, 4.9E-03, 1.3E-02)
Byron 1	0	84	(0.0E+00, 0.0E+00, 3.5E-02)	0.4	172.5	(2.4E-06, 2.3E-03, 9.6E-03)
Byron 2	0	128	(0.0E+00, 0.0E+00, 2.3E-02)	0.4	211.0	(1.7E-06, 1.9E-03, 7.8E-03)
Callaway	0	118	(0.0E+00, 0.0E+00, 2.5E-02)	0.4	202.3	(1.9E-06, 1.9E-03, 8.1E-03)
Calvert Cliffs 1	0	44	(0.0E+00, 0.0E+00, 6.6E-02)	0.4	136.3	(3.4E-06, 3.0E-03, 1.2E-02)
Calvert Cliffs 2	0	52	(0.0E+00, 0.0E+00, 5.6E-02)	0.4	143.7	(3.1E-06, 2.8E-03, 1.2E-02)
Catawba 1	3	93	(8.8E-03, 3.2E-02, 8.1E-02)	2.5	138.8	(4.2E-03, 1.8E-02, 3.9E-02)
Catawba 2	0	238	(0.0E+00, 0.0E+00, 1.3E-02)	0.4	305.4	(9.5E-07, 1.3E-03, 5.3E-03)
Comanche Peak 1	0	164	(0.0E+00, 0.0E+00, 1.8E-02)	0.4	242.1	(1.4E-06, 1.6E-03, 6.7E-03)
Comanche Peak 2	0	32	(0.0E+00, 0.0E+00, 8.9E-02)	0.4	125.0	(3.8E-06, 3.2E-03, 1.3E-02)
Cook 1	1	56	(9.2E-04, 1.8E-02, 8.2E-02)	1.2	133.4	(7.8E-04, 9.2E-03, 2.6E-02)
Cook 2	0	104	(0.0E+00, 0.0E+00, 2.8E-02)	0.4	190.1	(2.0E-06, 2.1E-03, 8.7E-03)
Crystal River 3	0	64	(0.0E+00, 0.0E+00, 4.6E-02)	0.4	154.6	(2.8E-06, 2.6E-03, 1.1E-02)
Davis-Besse	0	16	(0.0E+00, 0.0E+00, 1.7E-01)	0.4	109.6	(4.3E-06, 3.7E-03, 1.5E-02)
Diablo Canyon 1	0	116	(0.0E+00, 0.0E+00, 2.5E-02)	0.4	200.6	(1.9E-06, 2.0E-03, 8.2E-03)
Diablo Canyon 2	0	64	(0.0E+00, 0.0E+00, 4.6E-02)	0.4	154.6	(2.8E-06, 2.6E-03, 1.1E-02)
Farley 1	0	66	(0.0E+00, 0.0E+00, 4.4E-02)	0.4	156.4	(2.8E-06, 2.6E-03, 1.1E-02)
Farley 2	0	87	(0.0E+00, 0.0E+00, 3.4E-02)	0.4	175.1	(2.3E-06, 2.3E-03, 9.4E-03)
Fort Calhoun	0	10	(0.0E+00, 0.0E+00, 2.6E-01)	0.4	103.6	(4.5E-06, 3.9E-03, 1.6E-02)
Ginna	0	44	(0.0E+00, 0.0E+00, 6.6E-02)	0.4	136.3	(3.4E-06, 3.0E-03, 1.2E-02)
Haddam Neck	0	12	(0.0E+00, 0.0E+00, 2.2E-01)	0.4	105.6	(4.4E-06, 3.8E-03, 1.6E-02)
Harris	0	189	(0.0E+00, 0.0E+00, 1.6E-02)	0.4	263.6	(1.2E-06, 1.5E-03, 6.2E-03)
Indian Point 2	0	52	(0.0E+00, 0.0E+00, 5.6E-02)	0.4	143.7	(3.1E-06, 2.8E-03, 1.2E-02)
Indian Point 3	0	88	(0.0E+00, 0.0E+00, 3.3E-02)	0.4	176.0	(2.3E-06, 2.3E-03, 9.4E-03)
Kewaunee	0	0	—	—	—	—
Maine Yankee	0	36	(0.0E+00, 0.0E+00, 8.0E-02)	0.4	128.8	(3.6E-06, 3.1E-03, 1.3E-02)
Mcguire 1	0	108	(0.0E+00, 0.0E+00, 2.7E-02)	0.4	193.6	(2.0E-06, 2.0E-03, 8.5E-03)
Mcguire 2	0	104	(0.0E+00, 0.0E+00, 2.8E-02)	0.4	190.1	(2.0E-06, 2.1E-03, 8.7E-03)
Millstone 2	0	10	(0.0E+00, 0.0E+00, 2.6E-01)	0.4	103.6	(4.5E-06, 3.9E-03, 1.6E-02)
Millstone 3	1	136	(3.8E-04, 7.4E-03, 3.4E-02)	1.4	224.1	(6.1E-04, 6.1E-03, 1.6E-02)
North Anna 1	0	30	(0.0E+00, 0.0E+00, 9.5E-02)	0.4	123.1	(3.8E-06, 3.3E-03, 1.4E-02)
North Anna 2	0	27	(0.0E+00, 0.0E+00, 1.1E-01)	0.4	120.3	(3.9E-06, 3.4E-03, 1.4E-02)
Oconee 1	2	18	(2.0E-02, 1.1E-01, 3.1E-01)	1.4	65.5	(2.2E-03, 2.1E-02, 5.5E-02)
Oconee 2	0	20	(0.0E+00, 0.0E+00, 1.4E-01)	0.4	113.5	(4.2E-06, 3.6E-03, 1.5E-02)
Oconee 3	1	10	(5.1E-03, 1.0E-01, 3.9E-01)	1.0	76.6	(7.3E-04, 1.3E-02, 3.9E-02)
Palisades	0	26	(0.0E+00, 0.0E+00, 1.1E-01)	0.4	119.3	(4.0E-06, 3.4E-03, 1.4E-02)
Palo Verde 1	0	14	(0.0E+00, 0.0E+00, 1.9E-01)	0.4	107.6	(4.4E-06, 3.8E-03, 1.6E-02)
Palo Verde 2	0	29	(0.0E+00, 0.0E+00, 9.8E-02)	0.4	122.2	(3.9E-06, 3.3E-03, 1.4E-02)
Palo Verde 3	0	22	(0.0E+00, 0.0E+00, 1.3E-01)	0.4	115.4	(4.1E-06, 3.5E-03, 1.4E-02)
Point Beach 1	0	8	(0.0E+00, 0.0E+00, 3.1E-01)	0.4	101.5	(4.5E-06, 4.0E-03, 1.6E-02)
Point Beach 2	0	20	(0.0E+00, 0.0E+00, 1.4E-01)	0.4	113.5	(4.2E-06, 3.6E-03, 1.5E-02)

Table E-8. (continued).

Plant	Failures (f)	Demands (d)	Estimate (f/d) and C.I.[a]	Alpha	Beta	Bayes Mean and Interval
Prairie Island 1	0	18	(0.0E+00, 0.0E+00, 1.5E-01)	0.4	111.5	(4.2E-06, 3.6E-03, 1.5E-02)
Prairie Island 2	0	40	(0.0E+00, 0.0E+00, 7.2E-02)	0.4	132.6	(3.5E-06, 3.1E-03, 1.3E-02)
Robinson 2	0	42	(0.0E+00, 0.0E+00, 6.9E-02)	0.4	134.4	(3.4E-06, 3.0E-03, 1.2E-02)
Salem 1	0	64	(0.0E+00, 0.0E+00, 4.6E-02)	0.4	154.6	(2.8E-06, 2.6E-03, 1.1E-02)
Salem 2	0	88	(0.0E+00, 0.0E+00, 3.3E-02)	0.4	176.0	(2.3E-06, 2.3E-03, 9.4E-03)
San Onofre 2	0	41	(0.0E+00, 0.0E+00, 7.0E-02)	0.4	133.5	(3.5E-06, 3.0E-03, 1.3E-02)
San Onofre 3	0	53	(0.0E+00, 0.0E+00, 5.5E-02)	0.4	144.6	(3.1E-06, 2.8E-03, 1.2E-02)
Seabrook	1	68	(7.5E-04, 1.5E-02, 6.8E-02)	1.3	147.7	(7.6E-04, 8.6E-03, 2.3E-02)
Sequoyah 1	1	172	(3.0E-04, 5.8E-03, 2.7E-02)	1.4	262.4	(5.4E-04, 5.3E-03, 1.4E-02)
Sequoyah 2	0	242	(0.0E+00, 0.0E+00, 1.2E-02)	0.4	308.8	(9.4E-07, 1.2E-03, 5.2E-03)
South Texas 1	2	92	(3.9E-03, 2.2E-02, 6.7E-02)	2.0	155.3	(2.3E-03, 1.3E-02, 3.0E-02)
South Texas 2	0	115	(0.0E+00, 0.0E+00, 2.6E-02)	0.4	199.7	(1.9E-06, 2.0E-03, 8.2E-03)
St. Lucie 1	0	62	(0.0E+00, 0.0E+00, 4.7E-02)	0.4	152.8	(2.9E-06, 2.6E-03, 1.1E-02)
St. Lucie 2	1	40	(1.3E-03, 2.5E-02, 1.1E-01)	1.2	114.0	(7.9E-04, 1.0E-02, 2.9E-02)
Summer	0	57	(0.0E+00, 0.0E+00, 5.1E-02)	0.4	148.2	(3.0E-06, 2.7E-03, 1.1E-02)
Surry 1	0	78	(0.0E+00, 0.0E+00, 3.8E-02)	0.4	167.1	(2.5E-06, 2.4E-03, 9.9E-03)
Surry 2	0	96	(0.0E+00, 0.0E+00, 3.1E-02)	0.4	183.1	(2.2E-06, 2.2E-03, 9.0E-03)
Three Mile Isl 1	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	0.4	99.5	(4.6E-06, 4.1E-03, 1.7E-02)
Turkey Point 3	0	0	—	0.4	97.1	(6.1E-06, 4.3E-03, 1.8E-02)
Turkey Point 4	0	0	—	0.4	97.1	(6.1E-06, 4.3E-03, 1.8E-02)
Vogtle 1	3	314	(2.6E-03, 9.6E-03, 2.5E-02)	3.3	391.9	(2.5E-03, 8.3E-03, 1.7E-02)
Vogtle 2	0	130	(0.0E+00, 0.0E+00, 2.3E-02)	0.4	212.8	(1.7E-06, 1.8E-03, 7.7E-03)
Waterford 3	0	51	(0.0E+00, 0.0E+00, 5.7E-02)	0.4	142.7	(3.2E-06, 2.8E-03, 1.2E-02)
Wolf Creek	4	146	(9.4E-03, 2.7E-02, 6.2E-02)	3.5	187.4	(5.6E-03, 1.8E-02, 3.6E-02)
Zion 1	0	25	(0.0E+00, 0.0E+00, 1.1E-01)	0.4	118.3	(4.0E-06, 3.4E-03, 1.4E-02)
Zion 2	0	16	(0.0E+00, 0.0E+00, 1.7E-01)	0.4	109.6	(4.3E-06, 3.7E-03, 1.5E-02)
Population[c]	22	5226	(2.9E-03, 4.2E-03, 6.0E-03)	0.4	97.1	(6.1E-06, 4.3E-03, 1.8E-02)

a. The middle number is the maximum likelihood estimate, *f/d*, and the end numbers form a 90% confidence interval.

b. The end numbers form a 90% uncertainty interval based on the empirical Bayes beta distribution. The middle number is the mean.

c. The confidence interval is too short, since it assumes no variation between plants.

Table E-9. Probability of failure to recover from independent feed control segment failures, by plant.

Plant	Failures (*f*)	Demands (*d*)	Estimate (*f/d*) and C.I.[a]	Alpha	Beta	Bayes Mean and Interval
Arkansas 1	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Arkansas 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Beaver Valley 1	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Beaver Valley 2	1	1	(5.0E-02, 1.0E+00, 1.0E+00)	0.7	0.1	(2.5E-01, 8.8E-01, 1.0E+00)
Braidwood 1	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Braidwood 2	0	1	(0.0E+00, 0.0E+00, 9.5E-01)	0.1	0.7	(<1.0E-08, 1.5E-01, 8.4E-01)
Byron 1	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Byron 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Callaway	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Calvert Cliffs 1	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Calvert Cliffs 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Catawba 1	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	0.1	2.1	(<1.0E-08, 5.9E-02, 3.5E-01)
Catawba 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Comanche Peak 1	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Comanche Peak 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Cook 1	1	1	(5.0E-02, 1.0E+00, 1.0E+00)	0.7	0.1	(2.5E-01, 8.8E-01, 1.0E+00)
Cook 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Crystal River 3	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Davis-Besse	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Diablo Canyon 1	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Diablo Canyon 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Farley 1	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Farley 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Fort Calhoun	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Ginna	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Haddam Neck	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Harris	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Indian Point 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Indian Point 3	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Kewaunee	0	0	—	—	—	—
Maine Yankee	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Mcguire 1	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Mcguire 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Millstone 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Millstone 3	1	1	(5.0E-02, 1.0E+00, 1.0E+00)	0.7	0.1	(2.5E-01, 8.8E-01, 1.0E+00)
North Anna 1	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
North Anna 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Oconee 1	0	2	(0.0E+00, 0.0E+00, 7.8E-01)	0.1	1.4	(<1.0E-08, 8.4E-02, 5.1E-01)
Oconee 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Oconee 3	0	1	(0.0E+00, 0.0E+00, 9.5E-01)	0.1	0.7	(<1.0E-08, 1.5E-01, 8.4E-01)
Palisades	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Palo Verde 1	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Palo Verde 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Palo Verde 3	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Point Beach 1	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Point Beach 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)

Table E-9. (continued).

Plant	Failures (f)	Demands (d)	Estimate (f/d) and C.I.[a]	Alpha	Beta	Bayes Mean and Interval
Prairie Island 1	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Prairie Island 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Robinson 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Salem 1	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Salem 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
San Onofre 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
San Onofre 3	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Seabrook	1	1	(5.0E-02, 1.0E+00, 1.0E+00)	0.7	0.1	(2.5E-01, 8.8E-01, 1.0E+00)
Sequoyah 1	1	1	(5.0E-02, 1.0E+00, 1.0E+00)	0.7	0.1	(2.5E-01, 8.8E-01, 1.0E+00)
Sequoyah 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
South Texas 1	1	2	(2.5E-02, 5.0E-01, 9.7E-01)	1.2	1.1	(7.1E-02, 5.1E-01, 9.4E-01)
South Texas 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
St. Lucie 1	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
St. Lucie 2	1	1	(5.0E-02, 1.0E+00, 1.0E+00)	0.7	0.1	(2.5E-01, 8.8E-01, 1.0E+00)
Summer	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Surry 1	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Surry 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Three Mile Isl 1	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Turkey Point 3	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Turkey Point 4	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Vogtle 1	0	3	(0.0E+00, 0.0E+00, 6.3E-01)	0.1	2.1	(<1.0E-08, 5.9E-02, 3.5E-01)
Vogtle 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Waterford 3	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Wolf Creek	4	4	(4.7E-01, 1.0E+00, 1.0E+00)	3.1	0.1	(7.8E-01, 9.6E-01, 1.0E+00)
Zion 1	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Zion 2	0	0	—	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)
Population[c]	11	22	(3.1E-01, 5.0E-01, 6.9E-01)	0.2	0.2	(1.4E-05, 5.6E-01, 1.0E+00)

a. The middle number is the maximum likelihood estimate, *f/d*, and the end numbers form a 90% confidence interval.

b. The end numbers form a 90% uncertainty interval based on the empirical Bayes beta distribution. The middle number is the mean.

c. The confidence interval is too short, since it assumes no variation between plants.

Table E-10. Probability of failure of feed control segments from all causes, by plant (risk-based model).

Plant	Failures (*f*)	Demands (*d*)	Estimate (*f/d*) and C.I.[a]	Alpha	Beta	Bayes Mean and Interval
Arkansas 1	0	49	(0.0E+00, 0.0E+00, 5.9E-02)	0.5	131.6	(1.6E-05, 3.8E-03, 1.5E-02)
Arkansas 2	0	33	(0.0E+00, 0.0E+00, 8.7E-02)	0.5	116.9	(1.8E-05, 4.3E-03, 1.6E-02)
Beaver Valley 1	0	96	(0.0E+00, 0.0E+00, 3.1E-02)	0.5	173.5	(1.0E-05, 2.8E-03, 1.1E-02)
Beaver Valley 2	1	153	(3.4E-04, 6.5E-03, 3.1E-02)	1.5	236.4	(7.4E-04, 6.3E-03, 1.6E-02)
Braidwood 1	0	108	(0.0E+00, 0.0E+00, 2.7E-02)	0.5	184.1	(9.6E-06, 2.7E-03, 1.0E-02)
Braidwood 2	1	192	(2.7E-04, 5.2E-03, 2.4E-02)	1.5	275.8	(6.4E-04, 5.4E-03, 1.4E-02)
Byron 1	0	84	(0.0E+00, 0.0E+00, 3.5E-02)	0.5	163.0	(1.1E-05, 3.0E-03, 1.2E-02)
Byron 2	0	128	(0.0E+00, 0.0E+00, 2.3E-02)	0.5	201.5	(8.4E-06, 2.4E-03, 9.4E-03)
Callaway	0	118	(0.0E+00, 0.0E+00, 2.5E-02)	0.5	192.8	(8.9E-06, 2.5E-03, 9.8E-03)
Calvert Cliffs 1	0	44	(0.0E+00, 0.0E+00, 6.6E-02)	0.5	127.1	(1.6E-05, 4.0E-03, 1.5E-02)
Calvert Cliffs 2	0	52	(0.0E+00, 0.0E+00, 5.6E-02)	0.5	134.4	(1.5E-05, 3.7E-03, 1.4E-02)
Catawba 1	3	93	(8.8E-03, 3.2E-02, 8.1E-02)	2.9	147.9	(5.2E-03, 1.9E-02, 4.1E-02)
Catawba 2	4	238	(5.8E-03, 1.7E-02, 3.8E-02)	4.3	303.3	(5.0E-03, 1.4E-02, 2.6E-02)
Comanche Peak 1	0	164	(0.0E+00, 0.0E+00, 1.8E-02)	0.5	232.5	(6.8E-06, 2.1E-03, 8.1E-03)
Comanche Peak 2	0	32	(0.0E+00, 0.0E+00, 8.9E-02)	0.5	115.9	(1.8E-05, 4.3E-03, 1.7E-02)
Cook 1	1	56	(9.2E-04, 1.8E-02, 8.2E-02)	1.4	132.4	(1.1E-03, 1.1E-02, 2.8E-02)
Cook 2	4	104	(1.3E-02, 3.8E-02, 8.6E-02)	3.6	149.3	(7.5E-03, 2.4E-02, 4.7E-02)
Crystal River 3	0	64	(0.0E+00, 0.0E+00, 4.6E-02)	0.5	145.2	(1.4E-05, 3.4E-03, 1.3E-02)
Davis-Besse	0	16	(0.0E+00, 0.0E+00, 1.7E-01)	0.5	100.7	(2.1E-05, 5.0E-03, 1.9E-02)
Diablo Canyon 1	0	116	(0.0E+00, 0.0E+00, 2.5E-02)	0.5	191.0	(9.1E-06, 2.6E-03, 9.9E-03)
Diablo Canyon 2	0	64	(0.0E+00, 0.0E+00, 4.6E-02)	0.5	145.2	(1.4E-05, 3.4E-03, 1.3E-02)
Farley 1	0	66	(0.0E+00, 0.0E+00, 4.4E-02)	0.5	147.0	(1.3E-05, 3.4E-03, 1.3E-02)
Farley 2	0	87	(0.0E+00, 0.0E+00, 3.4E-02)	0.5	165.6	(1.1E-05, 3.0E-03, 1.1E-02)
Fort Calhoun	0	10	(0.0E+00, 0.0E+00, 2.6E-01)	0.5	94.8	(2.3E-05, 5.3E-03, 2.0E-02)
Ginna	0	44	(0.0E+00, 0.0E+00, 6.6E-02)	0.5	127.1	(1.6E-05, 4.0E-03, 1.5E-02)
Haddam Neck	0	12	(0.0E+00, 0.0E+00, 2.2E-01)	0.5	96.8	(2.2E-05, 5.2E-03, 2.0E-02)
Harris	0	189	(0.0E+00, 0.0E+00, 1.6E-02)	0.5	254.0	(5.9E-06, 1.9E-03, 7.3E-03)
Indian Point 2	0	52	(0.0E+00, 0.0E+00, 5.6E-02)	0.5	134.4	(1.5E-05, 3.7E-03, 1.4E-02)
Indian Point 3	0	88	(0.0E+00, 0.0E+00, 3.3E-02)	0.5	166.5	(1.1E-05, 3.0E-03, 1.1E-02)
Kewaunee	0	0	—	—	—	—
Maine Yankee	0	36	(0.0E+00, 0.0E+00, 8.0E-02)	0.5	119.7	(1.8E-05, 4.2E-03, 1.6E-02)
Mcguire 1	0	108	(0.0E+00, 0.0E+00, 2.7E-02)	0.5	184.1	(9.6E-06, 2.7E-03, 1.0E-02)
Mcguire 2	0	104	(0.0E+00, 0.0E+00, 2.8E-02)	0.5	180.6	(9.9E-06, 2.7E-03, 1.0E-02)
Millstone 2	0	10	(0.0E+00, 0.0E+00, 2.6E-01)	0.5	94.8	(2.3E-05, 5.3E-03, 2.0E-02)
Millstone 3	1	136	(3.8E-04, 7.4E-03, 3.4E-02)	1.5	218.9	(8.0E-04, 6.8E-03, 1.8E-02)
North Anna 1	0	30	(0.0E+00, 0.0E+00, 9.5E-02)	0.5	114.1	(1.9E-05, 4.4E-03, 1.7E-02)
North Anna 2	0	27	(0.0E+00, 0.0E+00, 1.1E-01)	0.5	111.2	(1.9E-05, 4.5E-03, 1.7E-02)
Oconee 1	2	18	(2.0E-02, 1.1E-01, 3.1E-01)	1.7	70.2	(3.5E-03, 2.4E-02, 5.9E-02)
Oconee 2	0	20	(0.0E+00, 0.0E+00, 1.4E-01)	0.5	104.5	(2.1E-05, 4.8E-03, 1.8E-02)
Oconee 3	1	10	(5.1E-03, 1.0E-01, 3.9E-01)	1.2	77.2	(1.2E-03, 1.5E-02, 4.3E-02)
Palisades	0	26	(0.0E+00, 0.0E+00, 1.1E-01)	0.5	110.3	(1.9E-05, 4.6E-03, 1.7E-02)
Palo Verde 1	0	14	(0.0E+00, 0.0E+00, 1.9E-01)	0.5	98.7	(2.2E-05, 5.1E-03, 1.9E-02)
Palo Verde 2	0	29	(0.0E+00, 0.0E+00, 9.8E-02)	0.5	113.1	(1.9E-05, 4.5E-03, 1.7E-02)
Palo Verde 3	0	22	(0.0E+00, 0.0E+00, 1.3E-01)	0.5	106.5	(2.0E-05, 4.7E-03, 1.8E-02)

Table E-10. (continued).

Plant	Failures (f)	Demands (d)	Estimate (f/d) and C.I.[a]	Alpha	Beta	Bayes Mean and Interval
Point Beach 1	0	8	(0.0E+00, 0.0E+00, 3.1E-01)	0.5	92.8	(2.3E-05, 5.4E-03, 2.1E-02)
Point Beach 2	0	20	(0.0E+00, 0.0E+00, 1.4E-01)	0.5	104.5	(2.1E-05, 4.8E-03, 1.8E-02)
Prairie Island 1	0	18	(0.0E+00, 0.0E+00, 1.5E-01)	0.5	102.6	(2.1E-05, 4.9E-03, 1.9E-02)
Prairie Island 2	0	40	(0.0E+00, 0.0E+00, 7.2E-02)	0.5	123.4	(1.7E-05, 4.1E-03, 1.6E-02)
Robinson 2	0	42	(0.0E+00, 0.0E+00, 6.9E-02)	0.5	125.2	(1.7E-05, 4.0E-03, 1.5E-02)
Salem 1	0	64	(0.0E+00, 0.0E+00, 4.6E-02)	0.5	145.2	(1.4E-05, 3.4E-03, 1.3E-02)
Salem 2	0	88	(0.0E+00, 0.0E+00, 3.3E-02)	0.5	166.5	(1.1E-05, 3.0E-03, 1.1E-02)
San Onofre 2	0	41	(0.0E+00, 0.0E+00, 7.0E-02)	0.5	124.3	(1.7E-05, 4.0E-03, 1.5E-02)
San Onofre 3	0	53	(0.0E+00, 0.0E+00, 5.5E-02)	0.5	135.3	(1.5E-05, 3.7E-03, 1.4E-02)
Seabrook	1	68	(7.5E-04, 1.5E-02, 6.8E-02)	1.4	146.0	(1.1E-03, 9.7E-03, 2.6E-02)
Sequoyah 1	1	172	(3.0E-04, 5.8E-03, 2.7E-02)	1.5	255.7	(6.9E-04, 5.8E-03, 1.5E-02)
Sequoyah 2	0	242	(0.0E+00, 0.0E+00, 1.2E-02)	0.5	299.4	(4.7E-06, 1.6E-03, 6.2E-03)
South Texas 1	2	92	(3.9E-03, 2.2E-02, 6.7E-02)	2.3	159.7	(2.9E-03, 1.4E-02, 3.2E-02)
South Texas 2	0	115	(0.0E+00, 0.0E+00, 2.6E-02)	0.5	190.2	(9.1E-06, 2.6E-03, 9.9E-03)
St. Lucie 1	0	62	(0.0E+00, 0.0E+00, 4.7E-02)	0.5	143.4	(1.4E-05, 3.5E-03, 1.3E-02)
St. Lucie 2	1	40	(1.3E-03, 2.5E-02, 1.1E-01)	1.4	113.8	(1.2E-03, 1.2E-02, 3.2E-02)
Summer	0	57	(0.0E+00, 0.0E+00, 5.1E-02)	0.5	138.9	(1.4E-05, 3.6E-03, 1.4E-02)
Surry 1	0	78	(0.0E+00, 0.0E+00, 3.8E-02)	0.5	157.7	(1.2E-05, 3.1E-03, 1.2E-02)
Surry 2	2	96	(3.7E-03, 2.1E-02, 6.4E-02)	2.3	164.4	(2.9E-03, 1.4E-02, 3.1E-02)
Three Mile Isl 1	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	0.5	90.8	(2.3E-05, 5.5E-03, 2.1E-02)
Turkey Point 3	0	0	—	0.5	87.8	(3.0E-05, 5.9E-03, 2.2E-02)
Turkey Point 4	0	0	—	0.5	87.8	(3.0E-05, 5.9E-03, 2.2E-02)
Vogtle 1	3	314	(2.6E-03, 9.6E-03, 2.5E-02)	3.5	391.8	(2.7E-03, 8.8E-03, 1.8E-02)
Vogtle 2	0	130	(0.0E+00, 0.0E+00, 2.3E-02)	0.5	203.2	(8.3E-06, 2.4E-03, 9.3E-03)
Waterford 3	0	51	(0.0E+00, 0.0E+00, 5.7E-02)	0.5	133.4	(1.5E-05, 3.8E-03, 1.4E-02)
Wolf Creek	4	146	(9.4E-03, 2.7E-02, 6.2E-02)	3.9	199.1	(6.6E-03, 1.9E-02, 3.7E-02)
Zion 1	0	25	(0.0E+00, 0.0E+00, 1.1E-01)	0.5	109.3	(2.0E-05, 4.6E-03, 1.8E-02)
Zion 2	0	16	(0.0E+00, 0.0E+00, 1.7E-01)	0.5	100.7	(2.1E-05, 5.0E-03, 1.9E-02)
Population[c]	32	5226	(4.5E-03, 6.1E-03, 8.2E-03)	0.5	87.8	(3.0E-05, 5.9E-03, 2.2E-02)

a. The middle number is the maximum likelihood estimate, f/d, and the end numbers form a 90% confidence interval.

b. The end numbers form a 90% uncertainty interval based on the empirical Bayes beta distribution. The middle number is the mean.

c. The confidence interval is too short, since it assumes no variation between plants.

Table E-11. Probability of failure of feed control segments from independent causes, by plant (operational model).

Plant	Failures (*f*)	Demands (*d*)	Estimate (*f/d*) and C.I.[a]	Alpha	Beta	Bayes Mean and Interval
Arkansas 1	0	49	(0.0E+00, 0.0E+00, 5.9E-02)	0.7	181.3	(7.6E-05, 3.9E-03, 1.3E-02)
Arkansas 2	0	33	(0.0E+00, 0.0E+00, 8.7E-02)	0.7	167.3	(8.5E-05, 4.3E-03, 1.4E-02)
Beaver Valley 1	0	96	(0.0E+00, 0.0E+00, 3.1E-02)	0.7	219.5	(5.5E-05, 3.2E-03, 1.1E-02)
Beaver Valley 2	1	153	(3.4E-04, 6.5E-03, 3.1E-02)	1.7	285.8	(8.6E-04, 5.9E-03, 1.5E-02)
Braidwood 1	0	108	(0.0E+00, 0.0E+00, 2.7E-02)	0.7	228.8	(5.1E-05, 3.0E-03, 1.0E-02)
Braidwood 2	1	192	(2.7E-04, 5.2E-03, 2.4E-02)	1.7	326.4	(7.6E-04, 5.2E-03, 1.3E-02)
Byron 1	0	84	(0.0E+00, 0.0E+00, 3.5E-02)	0.7	210.0	(5.9E-05, 3.3E-03, 1.1E-02)
Byron 2	0	128	(0.0E+00, 0.0E+00, 2.3E-02)	0.7	244.0	(4.5E-05, 2.8E-03, 9.6E-03)
Callaway	0	118	(0.0E+00, 0.0E+00, 2.5E-02)	0.7	236.4	(4.8E-05, 2.9E-03, 9.9E-03)
Calvert Cliffs 1	0	44	(0.0E+00, 0.0E+00, 6.6E-02)	0.7	177.0	(7.8E-05, 4.1E-03, 1.4E-02)
Calvert Cliffs 2	0	52	(0.0E+00, 0.0E+00, 5.6E-02)	0.7	183.8	(7.4E-05, 3.9E-03, 1.3E-02)
Catawba 1	3	93	(8.8E-03, 3.2E-02, 8.1E-02)	2.6	161.8	(3.9E-03, 1.6E-02, 3.5E-02)
Catawba 2	2	238	(1.5E-03, 8.4E-03, 2.6E-02)	2.7	363.4	(1.8E-03, 7.2E-03, 1.6E-02)
Comanche Peak 1	0	164	(0.0E+00, 0.0E+00, 1.8E-02)	0.7	271.0	(3.7E-05, 2.5E-03, 8.5E-03)
Comanche Peak 2	0	32	(0.0E+00, 0.0E+00, 8.9E-02)	0.7	166.4	(8.5E-05, 4.3E-03, 1.5E-02)
Cook 1	1	56	(9.2E-04, 1.8E-02, 8.2E-02)	1.5	172.9	(1.1E-03, 8.8E-03, 2.3E-02)
Cook 2	2	104	(3.4E-03, 1.9E-02, 5.9E-02)	2.3	203.0	(2.4E-03, 1.1E-02, 2.5E-02)
Crystal River 3	0	64	(0.0E+00, 0.0E+00, 4.6E-02)	0.7	193.8	(6.8E-05, 3.7E-03, 1.2E-02)
Davis-Besse	0	16	(0.0E+00, 0.0E+00, 1.7E-01)	0.7	151.5	(9.5E-05, 4.8E-03, 1.6E-02)
Diablo Canyon 1	0	116	(0.0E+00, 0.0E+00, 2.5E-02)	0.7	234.9	(4.8E-05, 2.9E-03, 1.0E-02)
Diablo Canyon 2	0	64	(0.0E+00, 0.0E+00, 4.6E-02)	0.7	193.8	(6.8E-05, 3.7E-03, 1.2E-02)
Farley 1	0	66	(0.0E+00, 0.0E+00, 4.4E-02)	0.7	195.5	(6.7E-05, 3.6E-03, 1.2E-02)
Farley 2	0	87	(0.0E+00, 0.0E+00, 3.4E-02)	0.7	212.4	(5.8E-05, 3.3E-03, 1.1E-02)
Fort Calhoun	0	10	(0.0E+00, 0.0E+00, 2.6E-01)	0.7	145.6	(9.8E-05, 5.0E-03, 1.7E-02)
Ginna	0	44	(0.0E+00, 0.0E+00, 6.6E-02)	0.7	177.0	(7.8E-05, 4.1E-03, 1.4E-02)
Haddam Neck	0	12	(0.0E+00, 0.0E+00, 2.2E-01)	0.7	147.6	(9.7E-05, 4.9E-03, 1.6E-02)
Harris	0	189	(0.0E+00, 0.0E+00, 1.6E-02)	0.7	289.4	(3.2E-05, 2.3E-03, 7.9E-03)
Indian Point 2	0	52	(0.0E+00, 0.0E+00, 5.6E-02)	0.7	183.8	(7.4E-05, 3.9E-03, 1.3E-02)
Indian Point 3	0	88	(0.0E+00, 0.0E+00, 3.3E-02)	0.7	213.2	(5.8E-05, 3.3E-03, 1.1E-02)
Kewaunee	0	0	—	—	—	—
Maine Yankee	0	36	(0.0E+00, 0.0E+00, 8.0E-02)	0.7	169.9	(8.3E-05, 4.2E-03, 1.4E-02)
Mcguire 1	0	108	(0.0E+00, 0.0E+00, 2.7E-02)	0.7	228.8	(5.1E-05, 3.0E-03, 1.0E-02)
Mcguire 2	0	104	(0.0E+00, 0.0E+00, 2.8E-02)	0.7	225.7	(5.2E-05, 3.1E-03, 1.0E-02)
Millstone 2	0	10	(0.0E+00, 0.0E+00, 2.6E-01)	0.7	145.6	(9.8E-05, 5.0E-03, 1.7E-02)
Millstone 3	1	136	(3.8E-04, 7.4E-03, 3.4E-02)	1.7	267.4	(9.0E-04, 6.3E-03, 1.6E-02)
North Anna 1	0	30	(0.0E+00, 0.0E+00, 9.5E-02)	0.7	164.5	(8.6E-05, 4.4E-03, 1.5E-02)
North Anna 2	0	27	(0.0E+00, 0.0E+00, 1.1E-01)	0.7	161.8	(8.8E-05, 4.5E-03, 1.5E-02)
Oconee 1	2	18	(2.0E-02, 1.1E-01, 3.1E-01)	1.6	91.3	(2.2E-03, 1.7E-02, 4.3E-02)
Oconee 2	0	20	(0.0E+00, 0.0E+00, 1.4E-01)	0.7	155.3	(9.2E-05, 4.6E-03, 1.6E-02)
Oconee 3	1	10	(5.1E-03, 1.0E-01, 3.9E-01)	1.3	111.8	(1.1E-03, 1.1E-02, 3.1E-02)
Palisades	0	26	(0.0E+00, 0.0E+00, 1.1E-01)	0.7	160.9	(8.9E-05, 4.5E-03, 1.5E-02)
Palo Verde 1	0	14	(0.0E+00, 0.0E+00, 1.9E-01)	0.7	149.5	(9.6E-05, 4.8E-03, 1.6E-02)
Palo Verde 2	0	29	(0.0E+00, 0.0E+00, 9.8E-02)	0.7	163.6	(8.7E-05, 4.4E-03, 1.5E-02)

Table E-11. (continued).

Plant	Failures (*f*)	Demands (*d*)	Estimate (*f/d*) and C.I.[a]	Alpha	Beta	Bayes Mean and Interval
Palo Verde 3	0	22	(0.0E+00, 0.0E+00, 1.3E-01)	0.7	157.2	(9.1E-05, 4.6E-03, 1.5E-02)
Point Beach 1	0	8	(0.0E+00, 0.0E+00, 3.1E-01)	0.7	143.6	(9.9E-05, 5.0E-03, 1.7E-02)
Point Beach 2	0	20	(0.0E+00, 0.0E+00, 1.4E-01)	0.7	155.3	(9.2E-05, 4.6E-03, 1.6E-02)
Prairie Island 1	0	18	(0.0E+00, 0.0E+00, 1.5E-01)	0.7	153.4	(9.4E-05, 4.7E-03, 1.6E-02)
Prairie Island 2	0	40	(0.0E+00, 0.0E+00, 7.2E-02)	0.7	173.5	(8.1E-05, 4.1E-03, 1.4E-02)
Robinson 2	0	42	(0.0E+00, 0.0E+00, 6.9E-02)	0.7	175.2	(7.9E-05, 4.1E-03, 1.4E-02)
Salem 1	0	64	(0.0E+00, 0.0E+00, 4.6E-02)	0.7	193.8	(6.8E-05, 3.7E-03, 1.2E-02)
Salem 2	0	88	(0.0E+00, 0.0E+00, 3.3E-02)	0.7	213.2	(5.8E-05, 3.3E-03, 1.1E-02)
San Onofre 2	0	41	(0.0E+00, 0.0E+00, 7.0E-02)	0.7	174.3	(8.0E-05, 4.1E-03, 1.4E-02)
San Onofre 3	0	53	(0.0E+00, 0.0E+00, 5.5E-02)	0.7	184.7	(7.3E-05, 3.9E-03, 1.3E-02)
Seabrook	1	68	(7.5E-04, 1.5E-02, 6.8E-02)	1.6	188.1	(1.1E-03, 8.3E-03, 2.1E-02)
Sequoyah 1	1	172	(3.0E-04, 5.8E-03, 2.7E-02)	1.7	305.9	(8.1E-04, 5.6E-03, 1.4E-02)
Sequoyah 2	0	242	(0.0E+00, 0.0E+00, 1.2E-02)	0.6	327.9	(2.5E-05, 2.0E-03, 6.9E-03)
South Texas 1	2	92	(3.9E-03, 2.2E-02, 6.7E-02)	2.2	187.5	(2.4E-03, 1.2E-02, 2.7E-02)
South Texas 2	0	115	(0.0E+00, 0.0E+00, 2.6E-02)	0.7	234.1	(4.8E-05, 2.9E-03, 1.0E-02)
St. Lucie 1	0	62	(0.0E+00, 0.0E+00, 4.7E-02)	0.7	192.2	(6.9E-05, 3.7E-03, 1.2E-02)
St. Lucie 2	1	40	(1.3E-03, 2.5E-02, 1.1E-01)	1.5	152.1	(1.1E-03, 9.6E-03, 2.5E-02)
Summer	0	57	(0.0E+00, 0.0E+00, 5.1E-02)	0.7	188.0	(7.1E-05, 3.8E-03, 1.3E-02)
Surry 1	0	78	(0.0E+00, 0.0E+00, 3.8E-02)	0.7	205.2	(6.2E-05, 3.4E-03, 1.2E-02)
Surry 2	2	96	(3.7E-03, 2.1E-02, 6.4E-02)	2.3	192.7	(2.4E-03, 1.2E-02, 2.6E-02)
Three Mile Isl 1	0	6	(0.0E+00, 0.0E+00, 3.9E-01)	0.7	141.6	(1.0E-04, 5.1E-03, 1.7E-02)
Turkey Point 3	0	0	—	0.8	142.0	(1.2E-04, 5.3E-03, 1.7E-02)
Turkey Point 4	0	0	—	0.8	142.0	(1.2E-04, 5.3E-03, 1.7E-02)
Vogtle 1	3	314	(2.6E-03, 9.6E-03, 2.5E-02)	3.6	431.8	(2.6E-03, 8.2E-03, 1.6E-02)
Vogtle 2	0	130	(0.0E+00, 0.0E+00, 2.3E-02)	0.7	245.6	(4.4E-05, 2.8E-03, 9.5E-03)
Waterford 3	0	51	(0.0E+00, 0.0E+00, 5.7E-02)	0.7	183.0	(7.5E-05, 3.9E-03, 1.3E-02)
Wolf Creek	4	146	(9.4E-03, 2.7E-02, 6.2E-02)	3.5	206.5	(5.1E-03, 1.6E-02, 3.3E-02)
Zion 1	0	25	(0.0E+00, 0.0E+00, 1.1E-01)	0.7	160.0	(8.9E-05, 4.5E-03, 1.5E-02)
Zion 2	0	16	(0.0E+00, 0.0E+00, 1.7E-01)	0.7	151.5	(9.5E-05, 4.8E-03, 1.6E-02)
Population[c]	28	5226	(3.8E-03, 5.4E-03, 7.3E-03)	0.8	142.0	(1.2E-04, 5.3E-03, 1.7E-02)

a. The middle number is the maximum likelihood estimate, *f/d*, and the end numbers form a 90% confidence interval.

b. The end numbers form a 90% uncertainty interval based on the empirical Bayes beta distribution. The middle number is the mean.

c. The confidence interval is too short, since it assumes no variation between plants.

Table E-12. Rate of pump-related failures to run from all causes pooled across train types, by plant.

Plant	Failures (f)	Time (hr) (T)	Estimate (f/T) and C.I.[a]	Alpha	Beta	Bayes Mean and Interval
Arkansas 1	0	17.8	(0.0E+00, 0.0E+00, 1.7E-01)	0.04	77.2	(<1.0E-08, 5.3E-04, 2.6E-03)
Arkansas 2	0	25.7	(0.0E+00, 0.0E+00, 1.2E-01)	0.04	85.0	(<1.0E-08, 4.8E-04, 2.3E-03)
Beaver Valley 1	0	57.9	(0.0E+00, 0.0E+00, 5.2E-02)	0.04	116.2	(<1.0E-08, 3.5E-04, 1.7E-03)
Beaver Valley 2	0	109.2	(0.0E+00, 0.0E+00, 2.7E-02)	0.04	165.1	(<1.0E-08, 2.4E-04, 1.2E-03)
Braidwood 1	0	39.3	(0.0E+00, 0.0E+00, 7.6E-02)	0.04	98.2	(<1.0E-08, 4.1E-04, 2.0E-03)
Braidwood 2	0	67.8	(0.0E+00, 0.0E+00, 4.4E-02)	0.04	125.7	(<1.0E-08, 3.2E-04, 1.6E-03)
Byron 1	0	22.9	(0.0E+00, 0.0E+00, 1.3E-01)	0.04	82.3	(<1.0E-08, 5.0E-04, 2.4E-03)
Byron 2	0	39.0	(0.0E+00, 0.0E+00, 7.7E-02)	0.04	98.0	(<1.0E-08, 4.2E-04, 2.0E-03)
Callaway	0	138.1	(0.0E+00, 0.0E+00, 2.2E-02)	0.04	192.5	(<1.0E-08, 2.1E-04, 1.0E-03)
Calvert Cliffs 1	0	26.8	(0.0E+00, 0.0E+00, 1.1E-01)	0.04	86.1	(<1.0E-08, 4.7E-04, 2.3E-03)
Calvert Cliffs 2	0	38.9	(0.0E+00, 0.0E+00, 7.7E-02)	0.04	97.9	(<1.0E-08, 4.2E-04, 2.0E-03)
Catawba 1	0	168.6	(0.0E+00, 0.0E+00, 1.8E-02)	0.04	221.3	(<1.0E-08, 1.8E-04, 8.7E-04)
Catawba 2	0	322.3	(0.0E+00, 0.0E+00, 9.3E-03)	0.04	365.9	(<1.0E-08, 1.1E-04, 5.2E-04)
Comanche Peak 1	0	158.7	(0.0E+00, 0.0E+00, 1.9E-02)	0.04	211.9	(<1.0E-08, 1.9E-04, 9.1E-04)
Comanche Peak 2	0	28.2	(0.0E+00, 0.0E+00, 1.1E-01)	0.04	87.4	(<1.0E-08, 4.7E-04, 2.3E-03)
Cook 1	0	44.6	(0.0E+00, 0.0E+00, 6.7E-02)	0.04	103.4	(<1.0E-08, 3.9E-04, 1.9E-03)
Cook 2	0	84.4	(0.0E+00, 0.0E+00, 3.5E-02)	0.04	141.6	(<1.0E-08, 2.9E-04, 1.4E-03)
Crystal River 3	0	32.7	(0.0E+00, 0.0E+00, 9.2E-02)	0.04	91.9	(<1.0E-08, 4.4E-04, 2.2E-03)
Davis-Besse	0	4.9	(0.0E+00, 0.0E+00, 6.1E-01)	0.04	64.3	(<1.0E-08, 6.3E-04, 3.0E-03)
Diablo Canyon 1	0	112.1	(0.0E+00, 0.0E+00, 2.7E-02)	0.04	167.9	(<1.0E-08, 2.4E-04, 1.2E-03)
Diablo Canyon 2	0	71.3	(0.0E+00, 0.0E+00, 4.2E-02)	0.04	129.1	(<1.0E-08, 3.1E-04, 1.5E-03)
Farley 1	0	78.8	(0.0E+00, 0.0E+00, 3.8E-02)	0.04	136.2	(<1.0E-08, 3.0E-04, 1.4E-03)
Farley 2	0	127.9	(0.0E+00, 0.0E+00, 2.3E-02)	0.04	182.8	(<1.0E-08, 2.2E-04, 1.1E-03)
Fort Calhoun	0	16.6	(0.0E+00, 0.0E+00, 1.8E-01)	0.04	76.0	(<1.0E-08, 5.4E-04, 2.6E-03)
Ginna	1	70.0	(7.3E-04, 1.4E-02, 6.8E-02)	0.71	89.4	(1.5E-04, 8.0E-03, 2.7E-02)
Haddam Neck	0	3.7	(0.0E+00, 0.0E+00, 8.1E-01)	0.04	63.1	(<1.0E-08, 6.4E-04, 3.1E-03)
Harris	0	222.6	(0.0E+00, 0.0E+00, 1.3E-02)	0.04	272.1	(<1.0E-08, 1.5E-04, 7.0E-04)
Indian Point 2	0	53.3	(0.0E+00, 0.0E+00, 5.6E-02)	0.04	111.8	(<1.0E-08, 3.6E-04, 1.8E-03)
Indian Point 3	0	76.7	(0.0E+00, 0.0E+00, 3.9E-02)	0.04	134.2	(<1.0E-08, 3.0E-04, 1.5E-03)
Kewaunee	0	63.1	(0.0E+00, 0.0E+00, 4.7E-02)	0.04	121.2	(<1.0E-08, 3.4E-04, 1.6E-03)
Maine Yankee	0	54.2	(0.0E+00, 0.0E+00, 5.5E-02)	0.04	112.7	(<1.0E-08, 3.6E-04, 1.7E-03)
Mcguire 1	0	93.8	(0.0E+00, 0.0E+00, 3.2E-02)	0.04	150.5	(<1.0E-08, 2.7E-04, 1.3E-03)
Mcguire 2	0	92.0	(0.0E+00, 0.0E+00, 3.3E-02)	0.04	148.8	(<1.0E-08, 2.7E-04, 1.3E-03)
Millstone 2	0	24.7	(0.0E+00, 0.0E+00, 1.2E-01)	0.04	84.0	(<1.0E-08, 4.9E-04, 2.4E-03)
Millstone 3	0	130.7	(0.0E+00, 0.0E+00, 2.3E-02)	0.04	185.5	(<1.0E-08, 2.2E-04, 1.0E-03)
North Anna 1	0	47.2	(0.0E+00, 0.0E+00, 6.4E-02)	0.04	105.9	(<1.0E-08, 3.8E-04, 1.9E-03)
North Anna 2	0	42.6	(0.0E+00, 0.0E+00, 7.0E-02)	0.04	101.5	(<1.0E-08, 4.0E-04, 1.9E-03)
Oconee 1	0	42.6	(0.0E+00, 0.0E+00, 7.0E-02)	0.04	101.5	(<1.0E-08, 4.0E-04, 1.9E-03)
Oconee 2	0	48.7	(0.0E+00, 0.0E+00, 6.2E-02)	0.04	107.3	(<1.0E-08, 3.8E-04, 1.8E-03)
Oconee 3	0	27.4	(0.0E+00, 0.0E+00, 1.1E-01)	0.04	86.7	(<1.0E-08, 4.7E-04, 2.3E-03)
Palisades	0	31.3	(0.0E+00, 0.0E+00, 9.6E-02)	0.04	90.4	(<1.0E-08, 4.5E-04, 2.2E-03)
Palo Verde 1	0	16.5	(0.0E+00, 0.0E+00, 1.8E-01)	0.04	75.9	(<1.0E-08, 5.4E-04, 2.6E-03)
Palo Verde 2	0	28.9	(0.0E+00, 0.0E+00, 1.0E-01)	0.04	88.2	(<1.0E-08, 4.6E-04, 2.2E-03)
Palo Verde 3	0	22.4	(0.0E+00, 0.0E+00, 1.3E-01)	0.04	81.8	(<1.0E-08, 5.0E-04, 2.4E-03)

Table E-12. (continued).

Plant	Failures (f)	Time (hr) (T)	Estimate (f/T) and C.I.[a]	Alpha	Beta	Bayes Mean and Interval
Point Beach 1	0	18.9	(0.0E+00, 0.0E+00, 1.6E-01)	0.04	78.3	(<1.0E-08, 5.2E-04, 2.5E-03)
Point Beach 2	0	39.6	(0.0E+00, 0.0E+00, 7.6E-02)	0.04	98.5	(<1.0E-08, 4.1E-04, 2.0E-03)
Prairie Island 1	0	8.9	(0.0E+00, 0.0E+00, 3.4E-01)	0.04	68.3	(<1.0E-08, 5.9E-04, 2.9E-03)
Prairie Island 2	0	20.2	(0.0E+00, 0.0E+00, 1.5E-01)	0.04	79.6	(<1.0E-08, 5.1E-04, 2.5E-03)
Robinson 2	0	64.9	(0.0E+00, 0.0E+00, 4.6E-02)	0.04	122.9	(<1.0E-08, 3.3E-04, 1.6E-03)
Salem 1	0	59.0	(0.0E+00, 0.0E+00, 5.1E-02)	0.04	117.3	(<1.0E-08, 3.5E-04, 1.7E-03)
Salem 2	0	79.1	(0.0E+00, 0.0E+00, 3.8E-02)	0.04	136.5	(<1.0E-08, 3.0E-04, 1.4E-03)
San Onofre 2	0	35.0	(0.0E+00, 0.0E+00, 8.6E-02)	0.04	94.1	(<1.0E-08, 4.3E-04, 2.1E-03)
San Onofre 3	0	37.0	(0.0E+00, 0.0E+00, 8.1E-02)	0.04	96.0	(<1.0E-08, 4.2E-04, 2.1E-03)
Seabrook	0	48.8	(0.0E+00, 0.0E+00, 6.1E-02)	0.04	107.5	(<1.0E-08, 3.8E-04, 1.8E-03)
Sequoyah 1	0	78.5	(0.0E+00, 0.0E+00, 3.8E-02)	0.04	135.9	(<1.0E-08, 3.0E-04, 1.4E-03)
Sequoyah 2	0	102.9	(0.0E+00, 0.0E+00, 2.9E-02)	0.04	159.2	(<1.0E-08, 2.5E-04, 1.2E-03)
South Texas 1	0	167.8	(0.0E+00, 0.0E+00, 1.8E-02)	0.04	220.6	(<1.0E-08, 1.8E-04, 8.7E-04)
South Texas 2	0	220.8	(0.0E+00, 0.0E+00, 1.4E-02)	0.04	270.5	(<1.0E-08, 1.5E-04, 7.1E-04)
St. Lucie 1	0	91.7	(0.0E+00, 0.0E+00, 3.3E-02)	0.04	148.6	(<1.0E-08, 2.7E-04, 1.3E-03)
St. Lucie 2	0	52.1	(0.0E+00, 0.0E+00, 5.8E-02)	0.04	110.6	(<1.0E-08, 3.7E-04, 1.8E-03)
Summer	0	59.4	(0.0E+00, 0.0E+00, 5.0E-02)	0.04	117.7	(<1.0E-08, 3.5E-04, 1.7E-03)
Surry 1	0	63.2	(0.0E+00, 0.0E+00, 4.7E-02)	0.04	121.3	(<1.0E-08, 3.4E-04, 1.6E-03)
Surry 2	2	73.4	(4.8E-03, 2.7E-02, 8.6E-02)	1.06	70.1	(9.1E-04, 1.5E-02, 4.4E-02)
Three Mile Isl 1	0	16.0	(0.0E+00, 0.0E+00, 1.9E-01)	0.04	75.4	(<1.0E-08, 5.4E-04, 2.6E-03)
Turkey Point 3	0	9.3	(0.0E+00, 0.0E+00, 3.2E-01)	0.04	68.7	(<1.0E-08, 5.9E-04, 2.9E-03)
Turkey Point 4	0	24.0	(0.0E+00, 0.0E+00, 1.2E-01)	0.04	83.3	(<1.0E-08, 4.9E-04, 2.4E-03)
Vogtle 1	0	254.7	(0.0E+00, 0.0E+00, 1.2E-02)	0.04	302.4	(<1.0E-08, 1.3E-04, 6.3E-04)
Vogtle 2	0	110.2	(0.0E+00, 0.0E+00, 2.7E-02)	0.04	166.0	(<1.0E-08, 2.4E-04, 1.2E-03)
Waterford 3	0	110.9	(0.0E+00, 0.0E+00, 2.7E-02)	0.04	166.8	(<1.0E-08, 2.4E-04, 1.2E-03)
Wolf Creek	0	108.0	(0.0E+00, 0.0E+00, 2.8E-02)	0.04	164.0	(<1.0E-08, 2.5E-04, 1.2E-03)
Zion 1	0	31.3	(0.0E+00, 0.0E+00, 9.6E-02)	0.04	90.4	(<1.0E-08, 4.5E-04, 2.2E-03)
Zion 2	0	18.9	(0.0E+00, 0.0E+00, 1.6E-01)	0.04	78.3	(<1.0E-08, 5.2E-04, 2.5E-03)
Population[c]	3	5031.8	(1.6E-04, 6.0E-04, 1.5E-03)	0.04	61.1	(<1.0E-08, 6.8E-04, 3.3E-03)

a. The middle number is the maximum likelihood estimate, f/T, and the end numbers form a 90% confidence interval.

b. The end numbers form a 90% uncertainty interval based on the empirical Bayes gamma distribution. The middle number is the mean.

c. The confidence interval is too short, since it assumes no variation between plants.

E-2. COMMON CAUSE FAILURE PROBABILITY EVALUATION FROM LER UNPLANNED DEMANDS

Four types of common cause failure (CCF) events were included in the AFW system models. They were failure of motor trains to start; pump-related failures to run, across train types; failures in feed control segments; and failures in the turbine steam supplies. The failures were quantified by multiplying the total failure probability for a segment by the fraction of events for which multiple failures might be expected to occur. The total failure probability, Q_t, was estimated by summing all the individual component/segment failures for the segment and failure mode under consideration (regardless of whether they occurred in common cause events) and dividing by the total number of segment or component demands. The fraction of events, denoted as an *alpha factor*, was estimated using the common cause methodology and database described in Reference E-1. A comparison of the selected quantification method with a simple one based directly on the AFW LER data was performed.

In the alpha-factor method, separate factors are estimated for each level of redundancy lost in the CCFs. For the AFW application, only lethal failures were considered, i.e., losses of all redundant trains. With varying configurations for AFW among 11 defined design classes, several alpha factors were applied. For this comparison, the motor train failure to start alpha factor was selected, namely, the loss of two of two motor trains. The failure to run alpha factor for loss of three of three trains (e.g., two motor trains and one turbine train) was selected. Many configurations exist for the flow control segments; the alpha factor most comparable to the basic LER data was for the loss of four out of four segments (a typical scenario that might, for example, fail to feed four steam generators). A single alpha factor applies for the turbine steam supply: namely, for the loss of two of two segments.

For the AFW CCF evaluation, staggered testing was assumed. More specifically, the lethal probability for staggered testing is simply the alpha factor for failure of all trains multiplied by the Q_t estimated from the LER data. In the AFW evaluation, Q_t differed for operational and risk-based models for pump failures to run and for feed control problems.

The CCF methodology results in the estimation of a beta distribution for each alpha factor. Uncertainty intervals for the alpha factor-based CCF probability estimates were obtained by propagating the resulting means and variances for the alpha factors and Q_t through the equations used to calculate the desired probability estimates. The method is analogous to the discussion in Section A-3.2.1. With the exception of the turbine steam line failures, the Q_t distributions from the LER data came from the empirical Bayes method, selecting the beta distribution parameters that maximize the likelihood to account for between-plant variations. A simple Bayes distribution applied for the turbine steam line, since there was just one independent and no common cause failures among the unplanned demands. For pump-related failures to run, the Q_t originally obtained from the LER data is a rate, with a gamma distribution. It was converted to a probability assuming a mission time of 24 hours.

For motor train failures to start, two events occurred in which both trains were lost in the 1,993 AFW motor train demands. The two failures in 1,993 demands were analyzed in the same manner as the other failure modes in this study. No empirical Bayes distribution was fit to the data, so the mean and bounds come from the simple Bayes method based on the pooled data. Similarly, for pump-related failures across train types, 5,032 estimated hours of pump operation were identified for which different pump trains were actuated. One pump-related CCF occurred during the operation times. Although turbine steam CCFs were identified in the LER data from surveillance, none were seen in the 1,108 unplanned demands for which both turbine steam supplies were used.

The largest number of CCFs among the unplanned demands occurred in feed control segments. Four CCF events were observed: clams interfered with the motor train flow control segments at Catawba 2, cavitating venturi problems caused a loss of two common feed segments into one steam generator at Surry 2, mechanical problems affected two flow control valves segments from one motor train into two steam generators at Cook 2, and an incorrect setpoint affected flow from one motor train into two steam generators in an event 2 years later at Cook 2. These events occurred among a total of 5,226 unplanned demands. With four failures, an empirical Bayes distribution for variation between plants was found. The distribution is quite skewed, since two of the failures occurred at one plant.

The alpha factor results were compared with a mean and bounds derived solely from the LERs simply by counting, for each plant, the number of opportunities for multiple failures among the unplanned demands and the number of instances of such failures occurring. Since a demand for an AFW train represents an opportunity for a lethal event, the CCF lethal demands are merely the unplanned demands used in the estimation of the independent failure modes for AFW. That is, if a train or multiple trains succeeded, then the opportunity for a lethal event no longer exists and the event is a success. For the LER or historical estimate, there was one unrecovered CCF of both motor trains failing to start in the 1,993 opportunities for a lethal event. There were no lethal CCFs for the three motor train configurations. No lethal CCFs were identified for the pumps failing to run in 5,032 hours, the feed control segments in 5,226 demands, and the steam supply to the turbine in 1,108 demands. The comparison is rough, since the group size subject to possible common cause failures differs from plant to plant. The mean and bounds come from the simple Bayes method based on the pooled LER-only data period. The uncertainty bounds for the LER-only data do not include the uncertainty from differing demands and common cause group sizes.

Figure E-1 below shows the results of the comparisons. In the figure, *Alpha x/x* refers to x failures in a common cause group size of x. For each of the four failure modes under consideration, the alpha factor results follow the results based solely on the LER data (labeled "*Historical*").

Examination of Figure E-1 leads to the following observations:

- The uncertainty intervals derived from the alpha factors in every case overlap the intervals derived from the LER-only data

- The LER-based estimates are in all four cases higher than the alpha factor estimates

- The alpha factor estimates lie within the uncertainty band for the LER-only data for each failure mode

- The alpha factor methodology produced estimates that appear to be reasonable since none of the alpha estimates were greater than estimates derived strictly from the LER-only data

- The LER-only results are broad and not conclusive for turbine steam line failures since no CCF events were observed in a relative small number of unplanned demands.

There are a number of possible reasons for differences in the results from the alpha-factor method and the simple LER-only estimates. The data review for the CCF database, from which the alpha factors are derived, is focused on component-level failures. A possible reason for larger LER-only results is that the AFW system operational data analysis considers the system at a higher level, with different boundaries for assigning failures. The CCF database includes a larger set of data. The alpha factor analysis includes Nuclear Plant Reliability Data System (NPRDS) data, with provisions to deal with

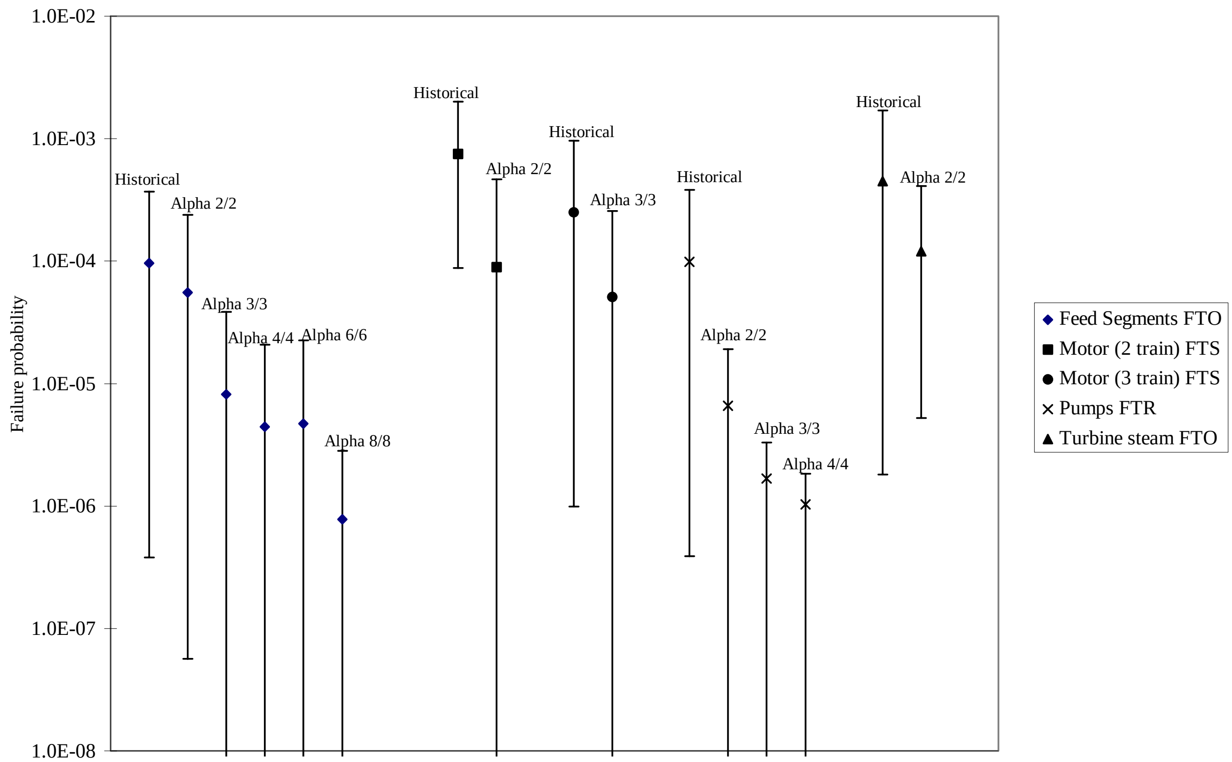

Figure E-1. Lethal common cause probabilities calculated by alpha factor methodology compared with estimates ("Historical") derived directly from the LER data.

partial failures and with uncertainty in whether an event represents a common cause failure at all. It accommodates potential failures and cases for which equipment was found to be degraded, although not demanded. It explicitly accounts for differences in the common cause group size.

In conclusion, the use of the alpha-factor methodology in this study allowed the estimation of lethal common cause failure probabilities for various group sizes corresponding to the plant-specific configurations. The LERs would be much too sparse if they were analyzed within plant design classes instead of across the industry. Furthermore, the LER crude count of common cause events and resulting bounds from Figure E-1 excludes the uncertainty from different group sizes and demand counts. Given these uncertainties, the comparison results seem reasonable.

E-3. PUMP RUN TIME EVALUATIONS

Pump run times were known from the LERs for 12.0% of the motor pump runs, 16.9% of the turbine pump runs, and 24.6% of the diesel pump runs that occurred during the unplanned demands. Unknown pump run times were estimated as the average of the known run times for the associated pumps. However, a concern exists that perhaps the events with failures in the AFW system are more likely to report run times, and that these times might be shorter than normal because of the failures themselves. The three observed failures to run among the unplanned demands were cases for which the run time prior to failure was not specified.

The data do show higher percentages of known run times among the failure events, even though some of the failures came from feed control segments. The percentages of known run times for motor, turbine, and diesel trains are 19.8%, 25.0%, and 100%, respectively, among the events with failures. Therefore, the two sets of run times were processed separately. Unknown run times for events with failures were estimated from the average associated pump run time of events with failures, and a separate average was computed and used for each pump time for unknown run times in events without failures.

The run times themselves do not appear to be significantly different among events with failures and events without failures. Figure E-2 gives a histogram of these times for the three pump types, with times for failure events shaded. In the figure, the number of observed known run times in a given bar is the number of times of duration greater than the hours of the previous bar and less than or equal to the hours of the specified bar. Thus, for example, among the 120 known motor train run times of duration less than or equal to one hour, 108 were not associated with any failure, and twelve run times were associated with a failure. The figure shows a similar pattern for the times with and without failures. The run times themselves do not appear to be significantly different among events with failures and events without failures. The failure set has a lower average time for motor-driven pumps, and a higher average time for turbine-driven pumps. A statistical test (using the *t* statistic) for differences between known pump run times among events with failures and events without failures was performed for each pump driver type. No statistically significant differences were found.

The uncertainty arising from the run time estimations was not modeled in the AFW study. It is not extremely large. For motor-driven pumps, the standard deviation of the known run times among the non-failure events is 4.1 hours, while it is 1.2 hours for the turbine run times and 0.4 hours for the diesel run times. The respective standard deviations among events with failures are 2.0, 1.0, and 0.02 hours, respectively. The standard deviation of the total estimated motor-driven pump run time for events with failures is 11.9% of the total estimated run time, while it is 24.6% among events without failures. Similar statistics for turbine-driven pumps are, respectively, 20.1% and 33.5%; and for diesels, the percentages are 19.0% and 1.2%. Pump times can be roughly expected to vary within two standard deviations from the mean. Thus, in the worst case of turbine-driven pumps among events with failures (representing 10% of the known run times), the actual exposure time might be 67% higher or lower than estimated. Therefore, the associated rate for failure to run from these events might be 67% higher or lower than estimated. For the total event set, the variation range for the turbine-driven pump failure rate is more like 40 to 50%. At the plant level, the greatest variation exists at the Catawba Station and at Oconee for both motor- and turbine-driven pump trains.

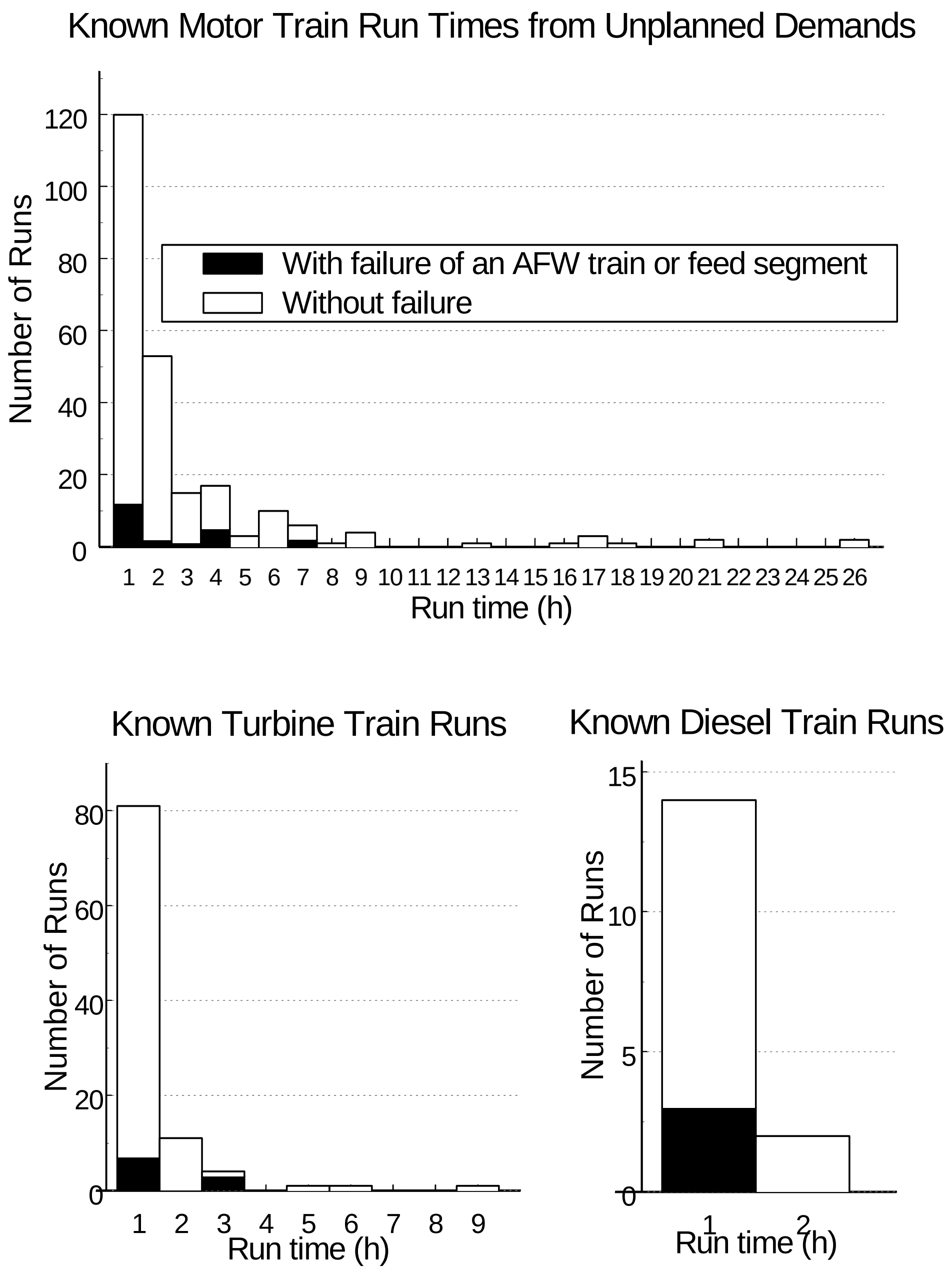

Figure E-2. Distribution of known AFW pump run times from unplanned demands.

E-4. INVESTIGATION OF RELATION TO PLANT LOW-POWER LICENSE DATE

The possibility of a trend in AFW performance with plant age as measured by a plant's low-power license date was investigated. This evaluation was performed for a plant-specific estimate of the unreliability, for the annual frequency of unplanned demands, and for the annual probability of selected types of failures on unplanned demands. For comparison, the unplanned scram frequency for the plants with AFW systems was also evaluated by low-power license date.

E-4.1 Unreliability Trends

Table E-13 shows AFW operational mission unreliabilities by plant, along with the plant low-power license date. To yield unreliabilities that were very sensitive to the plant data, plant-specific failure mode failure probabilities were constructed using constrained noninformative priors as described in Sections A-3.1.4 and A-3.1.5. The resulting updated distributions were combined for each plant as described in Section A-3.2.2.

Unreliability was analyzed graphically. A straight line was fitted to the unreliability and was also fitted to log (unreliability). The fit that accounted for more of the variation, as measured by R^2, was selected, provided that it also produced regression confidence limits greater than zero.

The results of the unreliability trend are displayed in Figure 8 in the main text. In the plot, the individual unreliabilities are marked by x's, each of which is surrounded by a bar showing the associated uncertainty obtained from IRRAS simulations. The trend line is plotted as a solid line, and a regression-based confidence band is shown by dashed lines. The confidence band describes the mean of the regression data at each point on the plant low-power license date scale. Calculation of the confidence band is described in many statistics books that treat linear regression (see the algorithm developed by Working, Hotelling, and Scheffé). The confidence band applies to every point of the fitted line simultaneously.

For the AFW data, a log model was required to avoid a part of the regression line being below zero. The slope of the log model was not significant (P-value = 0.18).

E-4.2 Trends in the Frequency of Unplanned Demands

For the unplanned demand frequency analyses, plant-specific event counts for the study period were normalized by the number of operational years during the study period for each plant. A total of 495.95 years of experience was represented among the 72 plants and 9 years in the study period. The resulting frequencies were trended against plant low-power license date using basically the same linear regression method as for the unreliabilities. The unplanned demands that were trended were the demands used for the unreliability analysis. Spurious actuations of the system were excluded.

As with the unreliabilities, log models were selected. The confidence interval for the mean of the AFW unplanned demands is negative for early low-power license dates, otherwise.

The same analysis methods were also applied for the frequency of unplanned scrams from power during the study period for the plants having AFW systems.

Table E-13. AFW unreliability for the operational mission, by plant, based on diffuse prior distributions and plant-specific data.[a]

Plant	Low-Power License Date	Constrained Noninformative Bayes Mean and 90% Interval
Haddam Neck	06/30/67	(3.4E-05, 4.9E-04, 1.6E-03)
Ginna	09/19/69	(3.8E-08, 2.8E-06, 1.2E-05)
Robinson 2	09/23/70	(1.7E-08, 2.6E-06, 1.1E-05)
Point Beach 1	10/05/70	(3.0E-08, 3.1E-06, 1.3E-05)
Surry 1	05/25/72	(2.4E-08, 3.0E-06, 1.3E-05)
Turkey Point 3	07/19/72	(1.1E-06, 1.1E-04, 4.9E-04)
Palisades	10/16/72	(1.2E-08, 2.8E-06, 1.3E-05)
Surry 2	01/29/73	(1.4E-08, 3.1E-06, 1.3E-05)
Oconee 1	02/06/73	(4.8E-07, 4.1E-05, 1.7E-04)
Point Beach 2	03/08/73	(2.7E-08, 2.9E-06, 1.2E-05)
Turkey Point 4	04/10/73	(1.5E-06, 1.1E-04, 4.8E-04)
Maine Yankee	06/29/73	(1.4E-08, 3.4E-06, 1.7E-05)
Fort Calhoun	08/09/73	(2.2E-06, 7.1E-05, 2.6E-04)
Indian Point 2	09/28/73	(5.2E-08, 2.9E-06, 1.2E-05)
Oconee 2	10/06/73	(1.1E-07, 2.2E-05, 9.3E-05)
Zion 1	10/19/73	(<1.0E-08, 1.8E-06, 8.7E-06)
Zion 2	11/14/73	(<1.0E-08, 1.8E-06, 8.8E-06)
Kewaunee	12/21/73	(<1.0E-08, 1.6E-06, 7.6E-06)
Prairie Island 1	04/05/74	(1.6E-06, 5.0E-05, 1.8E-04)
Three Mile Isl 1	04/19/74	(9.1E-08, 2.3E-05, 1.0E-04)
Arkansas 1	05/21/74	(9.4E-07, 3.7E-05, 1.4E-04)
Oconee 3	07/19/74	(3.7E-07, 3.9E-05, 1.6E-04)
Calvert Cliffs 1	07/31/74	(9.4E-08, 4.0E-06, 1.5E-05)
Cook 1	10/25/74	(8.1E-08, 3.3E-06, 1.2E-05)
Prairie Island 2	10/29/74	(1.5E-06, 4.4E-05, 1.6E-04)
Millstone 2	09/30/75	(1.5E-07, 2.2E-05, 1.1E-04)
Beaver Valley 1	01/30/76	(1.1E-08, 2.2E-06, 1.1E-05)
St. Lucie 1	03/01/76	(1.9E-08, 2.6E-06, 1.2E-05)
Indian Point 3	04/05/76	(1.2E-08, 1.9E-06, 8.7E-06)
Calvert Cliffs 2	11/30/76	(7.0E-08, 3.3E-06, 1.4E-05)
Salem 1	12/01/76	(2.1E-08, 2.0E-06, 8.9E-06)
Crystal River 3	01/28/77	(1.3E-06, 5.2E-05, 2.0E-04)
Davis-Besse	04/22/77	(1.4E-05, 3.8E-04, 1.4E-03)
Farley 1	06/25/77	(2.4E-08, 2.7E-06, 1.2E-05)
Cook 2	12/23/77	(2.3E-08, 1.7E-06, 8.0E-06)
North Anna 1	04/01/78	(5.6E-08, 3.9E-06, 1.6E-05)
Arkansas 2	09/01/78	(1.4E-06, 5.1E-05, 2.0E-04)
Sequoyah 1	02/29/80	(5.0E-08, 2.5E-06, 9.8E-06)
North Anna 2	04/11/80	(3.2E-08, 3.9E-06, 1.8E-05)
Salem 2	04/13/80	(2.0E-08, 1.8E-06, 8.7E-06)

Table E-13. (continued).

Plant	Low-Power License Date	Constrained Noninformative Bayes Mean and 90% Interval
Farley 2	10/23/80	(1.8E-08, 2.5E-06, 1.1E-05)
Mcguire 1	06/12/81	(3.1E-08, 2.0E-06, 8.7E-06)
Sequoyah 2	06/25/81	(2.4E-08, 1.9E-06, 8.5E-06)
San Onofre 2	02/16/82	(5.8E-08, 5.9E-06, 2.4E-05)
Summer	08/06/82	(1.5E-08, 2.6E-06, 1.2E-05)
San Onofre 3	11/15/82	(5.3E-08, 5.4E-06, 2.2E-05)
Mcguire 2	03/03/83	(1.9E-08, 1.9E-06, 8.2E-06)
St. Lucie 2	04/06/83	(6.4E-07, 1.1E-05, 3.9E-05)
Diablo Canyon 1	11/08/83	(<1.0E-08, 1.6E-06, 8.0E-06)
Callaway	06/11/84	(1.8E-08, 1.8E-06, 8.5E-06)
Byron 1	10/31/84	(3.9E-08, 1.4E-05, 5.7E-05)
Catawba 1	12/06/84	(3.0E-08, 2.2E-06, 9.3E-06)
Waterford 3	12/18/84	(5.1E-08, 4.7E-06, 2.0E-05)
Palo Verde 1	12/31/84	(1.3E-06, 5.5E-05, 2.1E-04)
Wolf Creek	03/11/85	(1.9E-07, 5.4E-06, 2.0E-05)
Diablo Canyon 2	04/26/85	(<1.0E-08, 1.7E-06, 8.2E-06)
Millstone 3	11/25/85	(1.3E-07, 3.3E-06, 1.2E-05)
Palo Verde 2	12/09/85	(1.2E-06, 4.7E-05, 1.8E-04)
Catawba 2	02/24/86	(2.7E-08, 2.0E-06, 8.4E-06)
Harris	10/24/86	(2.3E-08, 2.4E-06, 1.1E-05)
Byron 2	11/06/86	(7.6E-08, 1.8E-05, 7.6E-05)
Vogtle 1	01/16/87	(3.2E-08, 1.8E-06, 7.1E-06)
Palo Verde 3	03/25/87	(1.2E-06, 5.1E-05, 2.0E-04)
Braidwood 1	05/21/87	(4.0E-08, 1.4E-05, 5.3E-05)
Beaver Valley 2	05/28/87	(6.1E-08, 4.8E-06, 1.9E-05)
South Texas 1	08/21/87	(5.6E-07, 4.2E-05, 1.7E-04)
Braidwood 2	12/18/87	(4.2E-08, 1.2E-05, 4.5E-05)
South Texas 2	12/16/88	(<1.0E-08, 8.4E-06, 4.4E-05)
Vogtle 2	02/09/89	(1.6E-08, 1.7E-06, 8.2E-06)
Seabrook	05/26/89	(1.9E-06, 3.7E-05, 1.3E-04)
Comanche Peak 1	02/08/90	(4.6E-08, 2.4E-06, 9.9E-06)
Comanche Peak 2	02/02/93	(2.1E-08, 2.2E-06, 9.6E-06)

a. The calculations use a diffuse prior, updated by plant-specific data, for each failure mode.

The results of the demand frequency analyses are shown in the body of the report. Highly significant increasing trends with plant age were found for both AFW unplanned actuations and scrams (P-value (≤0.0005). The two frequencies are highly correlated, since scrams often result in a demand for AFW's safety function. The increase with low-power license date reflects the tendency of newer plants to have more unplanned scrams during their initial years of operation. Since the AFW study period goes back to 1987, the initial operation period is included for several of the plants with the most recent low-power license dates.

The analysis of the frequency of unplanned demands for the AFW system also showed significant differences between plants (P-value (≤0.0005).

E-4.3 Trends in the Failure Probabilities

Two considerations resulted in trending AFW failure probabilities rather than failure frequencies in this study. First, the exposure time for the occurrence of failures varies widely between plants and from one event to the next. Only in the unplanned AFW demand data are LERs written to describe what part of the AFW system is demanded in an event. A second consideration is that failures during surveillance and failures observed during operation are generally not required to be reported when redundant trains remain available. Consistent reporting of failures is expected only on the unplanned demands. When the failures are restricted to the unplanned demands, thus resulting in the same set of failures as used for the unreliability analysis, the natural normalization factor is the number of such train-level demands.

Failure probabilities were trended for motor trains, turbine trains, and feed segments. In each case, the probabilities were computed as the total number of relevant failures divided by the total number of unplanned demands on the associated segment for a selected plant. Failures of diesel trains, suction segments, and turbine steam supply segments were not trended because the data are sparse. Each of the three probability estimates was trended against plant low-power license date using basically the same linear regression method as for the unreliabilities. Maintenance events were excluded from the failures. Also, recovery was not considered in this analysis.

A detail of the methodology for trending the probabilities deserves mention. The log model cannot be used directly when a failure count is zero. Rather than simply use an (arbitrary) fraction of a failure divided by demands to estimate a non-zero failure probability for these cases, all the data for a particular probability were adjusted uniformly. The constrained noninformative prior distribution described in Section A-3 was updated with plant-specific data, and the resulting plant-specific mean was used for the probability. It was strictly positive, and therefore its logarithm was defined. For the AFW system frequencies, this adjustment effectively added approximately 0.5 to each failure count. It increased the demand count for motor trains, turbine trains, and feed control segments by, respectively, 3.1%, 1.9%, and 1.5%. This process results also in the calculation of 90% Bayesian uncertainty bounds for each probability. These bounds are shown in the plots as a rough indication of the variation present in the data for each plant.

The results of the failure probability analysis are shown in figures in the body of the report. Log models were used, and significant decreasing trends were found for motor trains (P-value = 0.0001). No trends were found for turbine trains or feed control segments.

E-5. ANALYSIS BY YEAR, 1987–1995

The analyses of Section E-4 were modified to see if there was a time trend during the period of the study. As in Section E-4, the analyses apply to unreliability, to two frequencies (unplanned AFW demand events and unplanned scram events), and to three failure probabilities (motor train failures, turbine train failures, and feed control segment failures). In addition, the total failure probability, combining trains of all types and their associated demands, was evaluated by calendar year.

E-5.1 Unreliability Trends

Table E-14 shows the unreliability by year for the operational model. The estimates are obtained in a manner similar to Section E-4, but the data used to update the constrained noninformative prior for each failure mode are pooled across plants for each calendar year instead of across calendar year for each plant.

Another difference is that IRRAS runs were performed for each plant design class, for each year. The results were combined into a weighted average and associated distribution for each year, with weights proportional to the number of plants in each class. A final difference from Section E-4 is that a log normal distribution was fitted to the mixture, rather than a beta distribution, because the resulting distribution was less skewed and had more realistic lower limits. These calculations are described in more detail in Section 3.2.2 of Appendix A.

The linear model method to test for a trend was the same as described in Section E-4, except that the time variable was calendar year instead of low-power license date. The log model was selected to avoid negative bounds in the regression analysis. The results are plotted, along with the associated log normal uncertainty limits and the regression mean confidence bounds in the main report. The slope of the trend was not statistically significant (P-value = 0.66).

Table E-14. AFW unreliability for the operational mission, by year, based on diffuse prior distributions and annual data.[a]

Year	Bayes Mean and 90% Interval
1987	(7.3E-07, 5.6E-05, 2.2E-04)
1988	(2.8E-07, 1.9E-05, 7.4E-05)
1989	(4.1E-07, 3.3E-05, 1.3E-04)
1990	(4.7E-07, 4.6E-05, 1.8E-04)
1991	(2.0E-07, 1.5E-05, 5.9E-05)
1992	(2.0E-07, 2.0E-05, 7.7E-05)
1993	(1.1E-07, 1.3E-05, 4.8E-05)
1994	(1.2E-07, 1.3E-05, 4.9E-05)
1995	(6.2E-07, 7.9E-05, 3.0E-04)

a. The upper and lower bounds form a 90% interval. The calculations use a diffuse prior, updated by year-specific data, for each failure mode.

E-5.2 Trends in the Frequency of Unplanned Demands

For each calendar year, both AFW unplanned demand frequencies and reactor trip frequencies among PWR plants were analyzed by pooling data from all the plants during each calendar year. Logarithmic models were selected to ensure positive trend lines.

For both the AFW unplanned demands and the reactor trips, a decreasing trend was found across the study period. As with the low-power license date analysis, these results are correlated. The AFW trends follow the scram trends, since most of the AFW unplanned demands result from scrams.

E-5.3 Trends in the Failure Probabilities

Trends in the probabilities of failures on unplanned demands were evaluated in a manner similar to Section E-4.3, except that the demands were pooled across plants for each calendar year instead of being pooled across calendar year for each plant. The probabilities were evaluated for motor trains, turbine trains, and feed control segments.

The total failure probability, including all non-maintenance failure events on unplanned demands, was also evaluated across years. Many different types of trains were thus combined here, resulting in a total train or segment-level demand of 11,636. Although such data represent a mixture, the population is relatively constant across the study period (other than general changes in the number of unplanned AFW demands). Plant-to-plant variability precluded this evaluation for the low-power license date evaluation.

In each of the four probability trend studies, the constrained noninformative prior update method was applied to the data to uniformly process the data and obtain estimates that are non-zero. This process is the same as for the low-power license date analysis. That is, the actual adjustments depend only on the total number of failures and demands, not on how the data are grouped (as by plant or by year). All of the models required the logarithmic transformation to avoid negative bounds with the raw data. With the Bayesian transformed data, log models were the best fit for the motor and turbine train data and were required to avoid negative bounds in the total failure data. The linear model was the best fit for the feed control segments.

The results are plotted in the main report. Trends were found only for the feed control segments. There, the P-value for a decreasing trend was 0.039.

E-6. REFERENCE

E-1. A. Mosleh and D. M. Rasmuson, *Common Cause Failure Data Collection and Analysis System Volume 5—Guidelines on Modeling Common Cause Failures in Probabilistic Risk Assessments (Draft)*, INEL-94/0064, December 1995.