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Precursors to Potential Severe Core Damage Accidents: 1998

A Status Report

Oak Ridge National Laboratory

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Abstract

This report describes the nine operational events in 1998 that affected eight commercial light-water reactors (LWRs) and that are considered to be precursors to potential severe core damage accidents. All these events had conditional probabilities of subsequent severe core damage greater than or equal to 1.0×10^{-6}. These events were identified by first computer-screening the 1998 licensee event reports from commercial LWRs to identify those events that could be precursors. Candidate precursors were selected and evaluated in a process similar to that used in previous assessments. Selected events underwent an engineering evaluation to identify, analyze, and document the precursors. Other events designated by the Nuclear Regulatory Commission (NRC) also underwent a similar evaluation. Finally, documented precursors were submitted for review by licensees and NRC headquarters to ensure that the plant design and its response to the precursor were correctly characterized. This study is a continuation of earlier work that evaluated 1969–1997 events. The report discusses the general rationale for this study, the selection and documentation of events as precursors, and the estimation of conditional probabilities of subsequent severe core damage for the events.

Contents

List of Figures

List of Tables

PREFACE

The Accident Sequence Precursor (ASP) Program was established at the Nuclear Operations Analysis Center (NOAC) at Oak Ridge National Laboratory (ORNL) in the summer of 1979. The first major report of that program was published in June 1982 and received extensive review. Seventeen reports documenting the review of operational events for precursors have been published in this program (see Sect. 5.0, Refs. 1–17). These reports describe events that occurred from 1969 through 1997. They have been completed on a yearly basis since 1986.

The current effort was undertaken on behalf of the Office of Research [formerly the Office for Analysis and Evaluation of Operational Data (AEOD)] of the Nuclear Regulatory Commission (NRC). The NRC Project Manager is Dr. P. D. O'Reilly.

The methodology developed and utilized in the ASP Program permits a reasonable estimate of the significance of operational events, including observed human and system interactions. The present effort for 1998 is a continuation of the assessment undertaken in the previous reports for operational events that occurred in 1969–1997.

Since 1992, in addition to NRC staff, the preliminary analyses were sent to the licensees for those plants for which potential precursors were identified. This method is similar to the review process used for the 1992–1997 events. All comments were evaluated, and analyses were revised as appropriate.

Reanalyses typically focused on and gave credit for equipment and procedures that provided additional protection against core damage. These additional features were beyond what had been included normally in past ASP analyses of events. Therefore, comparing and trending analysis results from prior years is more difficult because some analysis results before 1992 likely would have been different if additional information had been solicited from the licensees and incorporated.

For 1998 the total number of precursors identified is similar to the past several years. Revised models were used for the analysis of 1998 events—these models still utilize ASP class-based event trees and plant-specific linked fault trees but have been further updated to reflect more accurately individual plants. Because the Rev. 1 models were introduced in 1994 and Rev. 2 models were introduced in 1998, care must be used when comparing results from previous years.

The operational events selected in the ASP Program form a unique data base of historical system failures, multiple losses of redundancy, and infrequent core damage initiators. These events are useful in identifying significant weaknesses in design and operation, for trends analysis concerning industry performance, and for PRA-related information.

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FOREWORD

This report provides the results of the review and evaluation of 1998 operational experience data by the Nuclear Regulatory Commission's (NRC's) ongoing Accident Sequence Precursor (ASP) Program. The ASP Program provides a safety significance perspective of nuclear plant operational experience. The program uses probabilistic risk assessment (PRA) techniques to provide estimates of operating event significance in terms of the potential for core damage. The types of events evaluated include initiators, degradation of plant conditions, and safety equipment failures that could increase the probability of postulated accident sequences.

The primary objective of the ASP Program is to systematically evaluate U.S. nuclear plant operating experience to identify, document, and rank those operating events that were most significant in terms of the potential for inadequate core cooling and core damage. In addition, the program has the following secondary objectives to: (1) categorize the precursors for plant specific and generic implications, (2) provide a measure that can be used to trend nuclear plant core damage risk, and (3) provide a partial check on PRA-predicted dominant core damage scenarios.

In recent years, licensees of U.S. nuclear plants have added safety equipment and have improved plant and emergency operating procedures. Some of these changes, particularly those involving use of alternate equipment or recovery actions in response to specific accident scenarios, can have a significant effect on the calculated conditional core damage probabilities for certain accident sequences. In order to provide assurance that ASP analyses accurately model the plant's response to the initiating event of interest and use appropriate assumptions regarding human performance and the availability of equipment, the preliminary ASP analyses of 1998 events were transmitted to the pertinent nuclear plant licensees and to the NRC staff for review. The licensees were requested to review and comment on the technical adequacy of the analyses, including a depiction of their plant equipment and equipment capabilities. Each of the review comments received from licensees and the NRC staff was evaluated for reasonableness and pertinence to the ASP analysis in an attempt to use realistic values. All of the preliminary precursors were reviewed, and the conditional core damage probability calculations were revised where appropriate. The objective of the review process was to provide as realistic an analysis of the risk significance of the event as possible. Once all comments received from the review of the preliminary analyses had been resolved, the final analyses were transmitted to the licensees and made publicly available at that time.

The total number of precursors (9) identified for 1998 is almost twice the number of precursors identified for 1997 (5), but is consistent with the previous two years (14 in 1996; 10 in 1995). Eight of the precursors for 1998 occurred at pressurized-water reactors (PWRs); one occurred at a boiling water reactor (BWR). One of the events had a conditional core damage probability (CCDP)$\geq 10^{-4}$, and is therefore considered an "important" precursor—the tornado-caused loss of offsite power at the Davis-Besse plant in June (CCDP $= 5.6 \times 10^{-4}$). A detailed discussion of this event is found in the report.

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List of Acronyms

ac	alternating current
ACB	air circuit breaker
AFW	auxiliary feedwater
AIT	augmented inspection team
ALARA	as low as reasonable achievable
ASP	Accident Sequence Precursor (Program)
ATWS	anticipated transient without scram
AVV	atmospheric vent valve
BOP	balance of plant
BWR	boiling-water reactor
BWST	borated water storage tank
CCDP	conditional core damage probability
CCDF	conditional core damage frequency
CCF	common-cause failure
CCW	component cooling water
CCWP	component cooling water pump
cd	core damage
CDF	core damage frequency
CDP	core damage probability
C/L	center line
CS	containment spray
CST	condensate storage tank
dc	direct current
DBNPS	Davis-Besse Nuclear Power Station
DG	diesel generator
DHR	decay heat removal
DLOOP	dual-unit LOOP
ECCS	emergency core cooling system
EDG	emergency diesel generator
EFW	emergency feedwater
EOP	emergency operating procedure
EP	electric power
EPRI	Electric Power Research Institute
ESF	engineered safety feature
FSAR	final safety analysis report
HE	human error
HELB	high energy line break
HEP	human error probability
HPCS	high-pressure core spray
HPI	high-pressure injection
HPR	high-pressure recirculation
HPSI	high-pressure safety injection

HRA	human reliability analysis
IIT	Incident Investigation Team
IPE	Individual Plant Examination
IPEEE	Individual Plant Examination External Events
IRRAS	Integrated Reliability and Risk Analysis System
kV	kilovolts
LBLOCA	large-break loss of coolant accident
LCO	limiting conditions of operation
LDST	letdown storage tank
LER	licensee event report
LOCA	loss-of-coolant accident
LOFW	loss of main feedwater
LOOP	loss of offsite power
LPCS	low-pressure core spray
LPI	low-pressure injection
LPR	low-pressure recirculation
LPS	liquid poison system
LPSI	low-pressure safety injection
LT	level transmitter
LWR	light-water reactors
MCC	motor-control center
MFL	main feedwater line
MFW	main feedwater
MGL	Multiple Greek Letter
MOV	motor-operated valve
MSIS	main steam isolation system
MSIV	main steam isolation valve
MSLB	main steam line break
MSSV	main steam safety valve
MWT	minimum wall thickness
NOAC	Nuclear Operations Analysis Center
NPSH	net positive suction head
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NSSS	nuclear steam supply system
OD	outside diameter
OOS	out of service
ORNL	Oak Ridge National Laboratory
PORV	power-operated relief valve
PRA	probabilistic risk assessment
PSA	probabilistic safety assessment
PWR	pressurized-water reactor
RAS	recirculation actuation signal
RAT	reserve auxiliary transformer
RB	reactor building
RBES	reactor building emergency sump

RCIC	reactor core isolation cooling
RCP	reactor coolant pump
RCS	reactor coolant system
RDS	reactor depressurization system
RES	Office of Research
RHR	residual heat removal
RPS	reactor protection system
RWST	refueling water storage tank
SBO	station blackout
SBODG	station blackout diesel generator
SCE	Southern California Edison
SCSS	Sequence Coding and Search System
SEALLOCA	Seal-LOCA
SG	steam generator
SGTR	steam generator tube rupture
SIT	special investigation team
SITA	self-initiated technical audit
SKI	Swedish Nuclear Power Inspectorate
SLOCA	small-break LOCA
SPAR	atandardized plant analysis risk
SPDS	safety parameter display system
SRO	senior reactor operator
SRV	safety relief valve
SSLOCA	small-small-break LOCA
SWC	salt water cooling
SWP	service water pump
SWS	service water system
TBV	turbine bypass valve
TDAFW	turbine-driven auxiliary feedwater (pump)
TRANS	transient
TRC	time-reliability correlation
TS	Technical Specifications
TSC	technical support center
UFSAR	updated final safety analysis report

1. Introduction

The Accident Sequence Precursor (ASP) Program involves the systematic review and evaluation of operational events or conditions that have occurred at licensed U.S. commercial light-water reactors (LWRs). The ASP Program identifies and categorizes precursors to potential severe core damage accident sequences. The present report is a continuation of the work published in NUREG/CR-2497, *Precursors to Potential Severe Core Damage Accidents: 1969–1979, A Status Report*,[1] as well as in later status reports.[2-17] This report details the review and evaluation of operational events that occurred in 1998 and were reported in licensee event reports (LERs). The requirements for LERs are given in the Title 10 of the Code of Federal Regulations, Part 50.73; reporting guidance is described in NUREG-1022, *Licensee Event Report System, Description of System and Guidelines for Reporting*.[18-20]

1.1 Background

The ASP Program owes its genesis to the Risk Assessment Review Group,[21] which concluded that "unidentified event sequences significant to risk might contribute... a small increment...[to the overall risk]." The report continues, "It is important, in our view, that potentially significant [accident] sequences, and precursors, as they occur, be subjected to the kind of analysis contained in WASH-1400."[Ref. 22]. Evaluations done for the 1969–1981 period were the first efforts in this type of analysis.

Accident sequences of interest are those that, if additional failures had occurred, would have resulted in inadequate core cooling that could have caused severe core damage. For example, a postulated loss-of-coolant accident (LOCA) with a reported failure of a high-pressure injection (HPI) system may be examined or studied. In this example, the precursor would be the HPI system failure.

Events considered to be potential precursors are analyzed, and a conditional probability of core damage is calculated. This probability is estimated by mapping failures observed during the event onto accident sequences in risk models. Those events with conditional probabilities of subsequent severe core damage $\geq 1.0 \times 10^{-6}$ are identified and documented as precursors.

1.2 Current Process

The current process for identifying, analyzing, and documenting precursors is described in detail in Chap. 2. Completed precursor analyses were transmitted for review by the responsible licensees and Nuclear Regulatory Commission (NRC) staff. All comments were evaluated, and the analyses were revised as appropriate.

The ASP Program uses the NRC's Sequence Coding and Search System (SCSS) data base to identify most LERs that are reviewed for potential precursors. The SCSS data base contained 1498 LERs for 1998. The ASP computer search algorithm selected 627 of these for engineering review as potential precursors. Of the 15 events that the NRC identified from other sources for engineering review, 2 events were not selected by the computer search. As a result 629 events were selected for review. Of these 629 events, 39 LERs (45 including revisions) were determined to be potentially significant. Of these 39, 26 LERs were rejected after detailed analysis, 1 LER was classified as containment-related, and 2 LERs were documented as "interesting" events. No LERs were determined to be impractical to analyze. Review and analysis of the events described in the remaining 10 LERs led to the identification of 9 precursors for 1998. The results of these analyses are shown in Tables 3.1–3.4.

Chapter 2 describes the selection and analysis process used for the review of 1998 events. Chapter 3 provides a tabulation of the precursors, a summary of the more important precursors, and insights gained from the analyses and results. Chapter 4 provides a glossary of terms, and Chapter 5 provides the list of references. The remainder of this report is divided into seven appendices: Appendix A describes the ASP calculational methodology, Appendix B describes the at-power precursors, Appendix C describes the basis for selection as a shutdown precursor, Appendix D contains the potentially significant events considered impractical to analyze, Appendix E describes the requirements for an event to be considered a "containment-related" event, Appendix F contains "interesting" events, and Appendix G contains the resolution of comments on the preliminary 1998 ASP analyses.

2. Selection Criteria and Quantification

2.1 Accident Sequence Precursor Selection Criteria

The ASP Program is concerned with the identification and documentation of operational events that have involved portions of core damage sequences and with the estimation of associated frequencies and probabilities.

Identification of precursors requires the review of operational events for instances in which plant functions that provide protection against core damage have been challenged or compromised. Based on previous experience with reactor plant operational events, it is known that most operational events can be directly or indirectly associated with four initiators: trip [which includes loss of main feedwater (LOFW) within its sequences], loss of offsite power (LOOP), small-break LOCA, and steam generator tube rupture (SGTR) [pressurized-water reactors (PWRs) only]. These four initiators are primarily associated with loss of core cooling. ASP Program staff members examine LERs and other event documentation to determine the impact that operational events have on potential core damage sequences associated with these initiators. (Operational events are occasionally identified that impact other initiators, such as a large-break LOCA. Unique models are developed to address these events.)

2.1.1 Precursors

This section describes the steps used to identify events requiring analysis. Figure 2.1 illustrates this process.

A computerized search of the SCSS data base at the Oak Ridge National Laboratory (ORNL) was conducted to identify LERs that met minimum selection criteria for precursors. This computerized search identified LERs potentially involving failures in plant systems that provide protective functions for the plant for core damage-related initiating events. A review of 4 years of precursor data and 1 year of LERs determined that this computerized search successfully identifies almost all precursors within a subset of approximately one-third to one-half of all LERs.

LERs were also selected for review if an Augmented Inspection Team (AIT) or Incident Investigation Team (IIT) report was written regarding the event. In addition, the NRC designated other events for inclusion in the review process.

Those events selected underwent one- or two-engineer review(s) to determine if the reported event should be examined in greater detail. Events that, in the judgment of the initial reviewing engineer, clearly failed to satisfy the ASP criteria for analysis as a potential precursor were not subject to another evaluation. All other events were reviewed by two engineers to determine if they met the ASP criteria for detailed analysis before the decision was made to reject or analyze the event. This initial review was a bounding review, meant to capture events that in any way appeared to deserve detailed review and to eliminate events that were clearly unimportant. This process involves eliminating events that satisfied predefined criteria for rejection and accepting all others as potentially significant and requiring analysis.

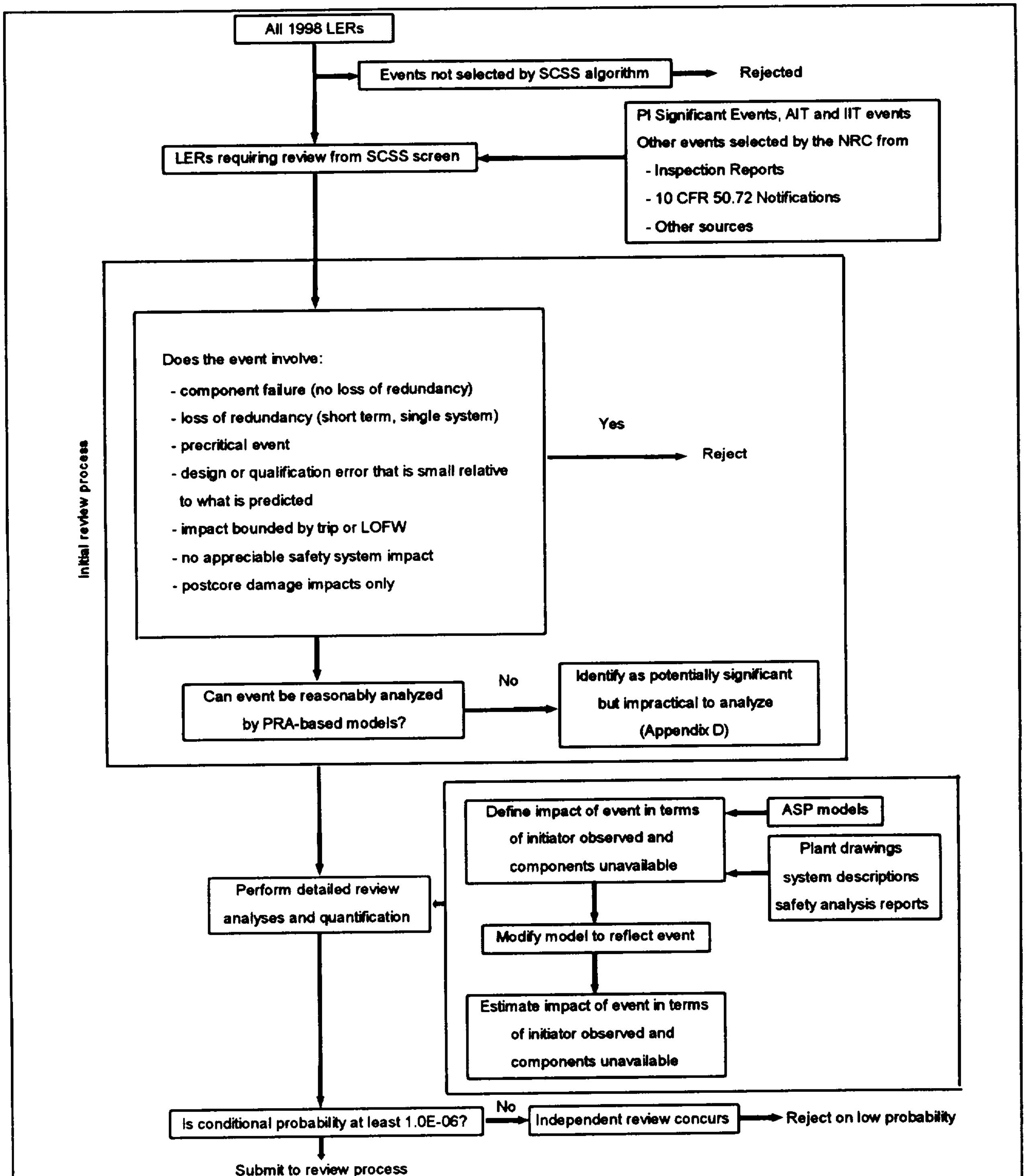

Fig. 2.1. ASP analysis process.

LERs were eliminated from further consideration as precursors if they involved only one of the following:

- a component failure with no loss of redundancy,
- a short-term loss of redundancy in only one system,
- an event that occurred prior to initial criticality,
- design or qualification error that was small relative to what was predicted (e.g., an error of a few percent in an actuation setpoint),
- an event bounded by a reactor trip or an LOFW,
- an event with no appreciable impact on safety systems, or
- an event involving only post-core-damage impacts.

Events identified for further consideration typically included the following:

- unexpected core damage initiators (LOOP, SGTR, and small-break LOCA);
- all events in which a reactor trip was demanded and a safety-related component failed;
- all support system failures, including failures in cooling water systems, instrument air, instrumentation and control, and electric power systems;
- any event in which two or more failures occurred;
- any event or operating condition that was not predicted or that proceeded differently from the plant design basis; and
- any event that, based on the reviewers' experience, could have resulted in or significantly affected a chain of events leading to potential severe core damage.

Events determined to be potentially significant as a result of this initial review were then subjected to a thorough, detailed analysis. This extensive analysis was intended to identify those events considered to be precursors to potential severe core damage accidents, either because of an initiating event or because of failures that could have affected the course of postulated off-normal events or accidents. These detailed analyses were not limited to the LERs; also used were final safety analysis reports (FSARs) and their amendments, individual plant examinations (IPEs), and other information related to the event of interest, which are available at ORNL and NRC.

The detailed analysis of each event considered the immediate impact of an initiating event or the potential impact of the equipment failures or operator errors on the readiness of systems in the plant for mitigation of off-normal and accident conditions. In the review of each selected event, three general scenarios (involving both the actual event and postulated additional failures) were considered.

1. If the event or failure was immediately detectable and occurred while the plant was at power, then the event was evaluated according to the likelihood that it and the ensuing plant response could lead to severe core damage.

2. If the event or failure had no immediate effect on plant operation (i.e., if no initiating event occurred), then the review considered whether the plant would require the failed items for mitigation of potential severe core damage sequences should a postulated initiating event occur during the failure period.

3. If the event or failure was identified while the plant was not at power, then the event was first assessed to determine whether it could have impacted at-power operation. If the event could have impacted at-power operation, its impact was assessed. If the event could only occur at cold shutdown or refueling shutdown, then its impact on continued decay heat removal during shutdown was assessed.

For each actual occurrence or postulated initiating event associated with an operational event reported in an LER, the sequence of operation of various mitigating systems required to prevent core damage was considered. Events were selected and documented as precursors to potential severe core damage accidents (accident sequence precursors) if the conditional probability of subsequent core damage was at least 1.0×10^{-6} (see Sect. 2.2). Events of low significance were thus excluded, allowing attention to be focused on the more important events. This approach is consistent with the approach used to define 1987–1997 precursors, but differs from that of earlier ASP reports which addressed all events meeting the precursor selection criteria regardless of conditional core damage probability.

Nine operational events with conditional probabilities of subsequent severe core damage $\geq 1.0 \times 10^{-6}$ were identified as accident sequence precursors. The nine events were analyzed as at-power events and are documented in Appendix B. Because no events were analyzed as shutdown events, a description of the basis of what constitutes a shutdown event is documented in Appendix C.

While review of LERs identified by this process is expected to identify almost all precursors, it is possible that a few precursors exist within the set of unreviewed LERs. Some potential precursors that would have been found if all 1998 LERs had been reviewed may not have been identified. Because of this, it should not be assumed that the set of 1988–1998 precursors is consistent with precursors identified in 1984–1987.

2.1.2 Potentially Significant Events Considered Impractical to Analyze

In some cases, events are impractical to analyze because of lack of information or inability to reasonably model within a probabilistic risk assessment (PRA) framework, considering the level of detail typically available in PRA models and the resources available to the ASP Program. Such events are thought to be capable of impacting core damage sequences. However, the events usually involve component degradations in which the extent of the degradation cannot be determined or the impact of the degradation on plant response cannot be ascertained.

None of the 1998 LERs were identified as potentially significant but impractical to analyze. A description of the basis for an event to be considered impractical to analyze is provided in Appendix D.

2.1.3 Containment-Related Events

Events involving loss of containment functions—such as containment cooling, containment spray, containment isolation (direct paths to the environment only), or hydrogen control—are classified as "containment-related" events. A review of the 1998 LERs resulted in one event being classified as containment-related. A description of the basis for an event to be considered to be a containment-related event, as well as a description of the one containment-related event, is provided in Appendix E.

2.1.4 "Interesting" Events

Events that provide insight into unusual failure modes with the potential to compromise continued core cooling but are not considered to be precursors are documented as "interesting" events. The review of the 1998 LERs resulted in two events being classified as interesting. These events are documented in Appendix F.

2.2 Precursor Quantification

Quantification of accident sequence precursor significance involves determination of a conditional probability of subsequent severe core damage given the failures observed during an operational event. This probability is estimated by mapping failures observed during the event onto the ASP accident sequence models (event trees and linked fault trees modified to reflect the event), which depict potential paths to severe core damage, and calculating a conditional probability of core damage. The effect of a precursor on event tree branches is assessed by reviewing the operational event specifics against system design information. This information is used to modify the ASP model (typically the fault trees). Quantification results in a revised conditional probability of core damage given the operational event. The conditional probability estimated for each precursor is useful in ranking the precursors because it provides an estimate of the measure of protection against core damage that remains once the observed failures have occurred. Details of the event modeling process and calculational results can be found in Appendix A of this report.

The calculational approach used for the analysis of 1998 events was similar to that used for the 1994–1997 events. Linked fault tree models were used instead of the earlier event-tree-based models. The use of linked fault trees allows the impact of individual component failures to be more precisely addressed; this could only be approximated in the earlier models. Similar to previous years, the conditional core damage probability (CCDP) during the time period in which the failures were observed was used to rank the initiating event assessments. The importance measure, the difference between the CCDP and the nominal core damage probability (CDP) for the same period of time (i.e., the base-case probability), was used to rank the unavailability assessments.

For most events that meet the ASP selection criteria, the observed failures significantly impact the core damage model. In these cases, there is little numeric difference between the CCDP and the importance measure that was previously used (CCDP - CDP). For some events, however, the nominal plant response during the time period dominates the results. In these cases, the CCDP can be considerably higher than the importance measure (the impact of such a condition on plant response is relatively minor). By only looking at the CCDP for such an event, its significance may be overestimated. Therefore, for condition assessments, the CCDP, the CDP, and the difference between these values (i.e., the importance) are provided.

The initiating event frequencies and failure probabilities used in the calculations are derived in part from data obtained across the population of LWRs. An attempt has been made to make the frequencies and failure probabilities plant-specific. However, this effort is not complete. Because of this, the conditional probabilities determined for each precursor cannot be rigorously associated with the probability of severe core damage resulting from the actual event at the specific reactor plant where it occurred.

The evaluation of precursors in this report considers and, where appropriate, gives credit for additional equipment or recovery procedures at the plants. Accordingly, the evaluations for 1994–1998 are not directly comparable to the results for prior years. Examples of additional equipment and recovery procedures addressed since the 1994 analyses, when information was available, include use of supplemental emergency diesel generators (EDGs) for station blackout mitigation and alternate systems for steam generator (SG) and reactor coolant system (RCS) makeup.

2.3 Review of Precursor Documentation

This section describes the steps involved in the review of the preliminary precursor analyses. Figure 2.2 illustrates this process.

After completion of the initial analyses of the precursors, the analyses were transmitted to the pertinent nuclear plant licensees and to the NRC staff for review. If the analysis was performed by NRC staff (both Davis-Besse analyses, Big Rock Point, and Cook), the analysis was also transmitted to ORNL staff for review. The licensees were requested to review and comment on the technical adequacy of the analyses, including the depiction of their plant equipment and equipment capabilities. Each of the review comments was evaluated for applicability and pertinence to the ASP analysis. Comments were received for all of the preliminary precursors from all the responsible licensees.

Unlike the 1993–1997 events, the 1998 precursor analyses were not sent to an NRC contractor for an independent review, but were still reviewed in-house by the NRC.

After the preliminary analyses were revised based on licensee and NRC comments, the analyses were sent back to NRC for final comments, and revised again, if necessary.

In some cases the analysis results were affected as a result of comments received. In general, this was the result of incorporation of plant-specific equipment or strategies for mitigating events. Incorporation of these factors for only a subset of the analyses reduces the validity of ranking the events by CCDP. Consistent incorporation of these mitigation strategies across all of the events could affect the CCDP of some events and may affect the ranking of the events.

A summary of the comments received from the licensees and the NRC staff, as well as a response to each comment, can be found in Appendix G.

2.4 Precursor Documentation Format

The at-power precursors are contained in Appendix B; the basis for shutdown precursors is contained in Appendix C. A description of each event is provided with additional information relevant to the assessment of the event, the ASP modeling assumptions and approach used in the analysis, and the analysis results. A figure indicating the dominant core damage sequence postulated for each event is also included.

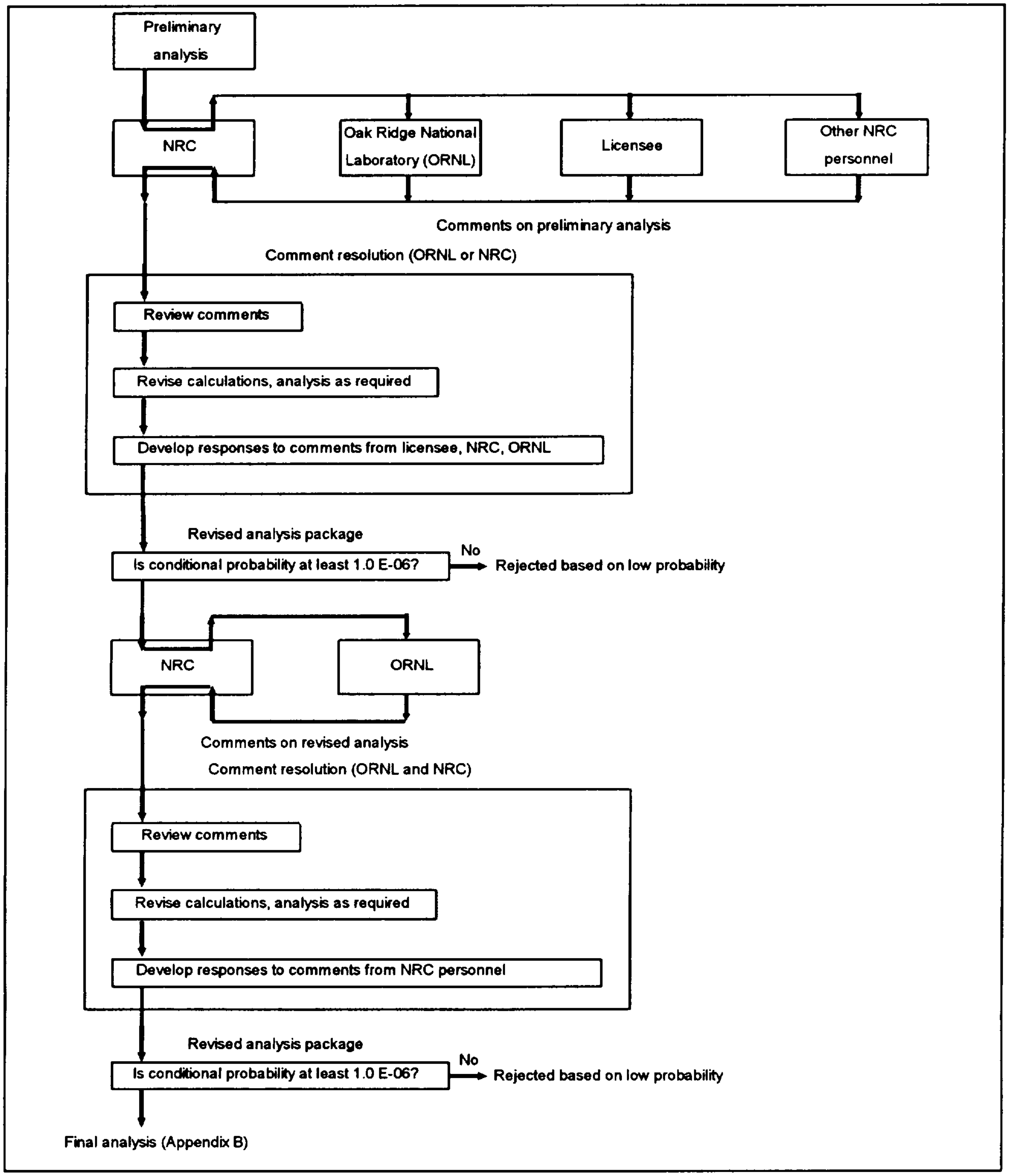

Fig. 2.2. ASP review process.

The CCDP calculation for each precursor is documented. The tables associated with each specific event analysis include selected basic event probabilities; sequence logic, probabilities, and importance; system names for higher probability sequences; and selected cut sets for higher probability sequences.

2.5 Potential Sources of Error

As with any analytic procedure, the availability of information and modeling assumptions can bias results. In this section, several of these potential sources of error are addressed.

1. *Evaluation of only a subset of 1998 LERs.* For 1969–1981 and 1984–1987, all LERs reported during the year were evaluated for precursors. For 1982–1983 and 1988–1998, only a subset of the LERs was evaluated in the ASP Program after a computerized search of the SCSS data base was performed by ORNL personnel. While this subset is thought to include most serious operational events, it is possible that some events that would normally be selected as precursors were missed because they were not included in the subset that resulted from the screening process.

2. *Inherent biases in the selection process.* Although the criteria for identification of an operational event as a precursor are fairly well defined, the selection of an LER for initial review can be somewhat judgmental. Events selected in the study were more serious than most (e.g., the event had safety-related component failures, a LOOP or LOCA occurred, numerous equipment failures, etc.). Hence, the majority of the LERs selected for detailed review would probably have been selected by other reviewers with experience in LWR systems and their operation. However, some differences would be expected to exist; thus, the selected set of precursors should not be considered unique.

3. *Lack of appropriate event information.* The accuracy and completeness of the LERs and other event-related documentation in reflecting pertinent operational information are questionable in some cases. Requirements associated with LER reporting (i.e., 10 CFR 50.73), plus the approach to event reporting practiced at particular plants, can result in variation in the extent of events reported and report details among plants. Although the LER rule of 1984 reduced the variation in reported details, some variation still exists. In addition, only details of the sequence (or partial sequences for failures discovered during testing) that actually occurred are usually provided; details concerning potential alternate sequences of interest in this study must often be inferred.

4. *Accuracy of the ASP models and probability data.* The event trees used in the analysis are plant-class specific and reflect differences between plants in the eight plant classes that have been defined. The fault trees are structured to reflect the plant-specific systems. While major differences between plants are represented in this way, the plant models may not adequately reflect all of the important differences such as the impact of potential support system failures (limited support system modeling is provided in the current models) and station blackout issues. Modeling improvements that address these problems are being pursued in the ASP Program.

   Because of the sparseness of system failure events, data from many plants must be combined to estimate the failure probability of a multitrain system or the frequency of low- and moderate-frequency events (such as

LOOPs and LOCAs). Because of this, the modeled response for each event will tend toward an average response for the plant class. If systems at the plant at which the event occurred are better or worse than average (difficult to ascertain without extensive operating experience), the actual conditional probability for an event could be higher or lower than that calculated in the analysis.

Known plant-specific equipment and procedures that can provide additional protection against core damage beyond the plant-class features included in the ASP models were addressed in the 1998 precursor analysis. This information was not uniformly available; much of it was provided in licensee comments on preliminary analyses and in IPE documentation available at the time this report was prepared. As a result, consideration of additional features may not be consistent between precursor analyses of events at different plants. However, multiple events that occurred at an individual plant or at similar units at the same site have been consistently analyzed.

5. *Difficulty in determining the potential for recovery of failed equipment.* Assignment of recovery credit for an event can have a significant impact on the assessment of the event. The approach used to assign recovery credit is described in Appendix A. The actual likelihood of failing to recover from an event at a particular plant is difficult to assess and may vary substantially from the values currently used in the ASP analyses. This difficulty is demonstrated in the genuine differences in opinion among analysts, operations and maintenance personnel, and others concerning the likelihood of recovering from specific failures (typically observed during testing) within a time period that would prevent core damage following an actual initiating event. Programmatic constraints have prevented substantial efforts in estimating actual recovery probabilities. The values currently used are based on a review of recovery actions during historic events and also include consideration of human error during recovery. These values have been reviewed both within and outside the ASP Program. While it is acknowledged that substantial uncertainty exists, these values are considered reasonable for estimating the risk associated with an operational event.

6. *Assumption of a 1-month test interval.* The core damage probability for precursors involving unavailabilities is calculated on the basis of the exposure time associated with the event. For failures discovered during testing, the time period is related to the test interval. A test interval of 1 month was assumed unless another interval was specified in the LER. See Ref. 2 for a more comprehensive discussion of test interval assumptions.

3. Results

This chapter summarizes the results of the review and evaluation of 1998 operational events. The primary result of the ASP Program is the identification of operational events with a CCDP or an importance $\geq 1.0 \times 10^{-6}$ that satisfy at least one of the four precursor selection criteria: (1) a core damage initiator requiring safety system response, (2) the failure of a system required to mitigate the consequences of a core damage initiator, (3) degradation of more than one system required for mitigation, or (4) a trip or LOFW with a degraded mitigating system. Nine of the events that occurred during 1998 were determined to have a CCDP or an importance $\geq 10^{-6}$ and were transmitted to the respective licensees for review and comment. These events are documented as precursors in Appendix B. No shutdown-related precursors were identified in the evaluation of 1998 events; Appendix C discusses the criteria for a shutdown-related precursor.

Direct comparison of results with those of earlier years is not possible without substantial effort to reconcile analysis differences. The major differences in the selection and modeling of events, which were implemented for event assessments for 1984, 1988, 1992, 1994, and 1998, are discussed below.

1984–1987 The revised LER rule, which went into effect in 1984, resulted in more LERs being selected for detailed review even though fewer LERs were reported. One requirement of the revised LER rule is the detailed reporting of all operational events involving a reactor trip. This allowed reactor trips with degraded mitigating systems to be analyzed as precursors (previously, the plant state at the time a degraded system was discovered could not always be discerned in the LERs). The new LER rule also required additional detail for those events that are reported.

Model changes during this period included using event trees that were developed on a plant-class basis to more accurately reflect plant response following an initiating event. The models also included additional mitigating systems that could prevent core damage. The system failure probabilities were estimated using simplified train-based system models. These probabilities were checked against observed failures in the 1984–1985 period. Section 5 in NUREG/CR-4674, Vol. 3, provides additional details of these changes.[4]

1988–1992 Two major types of changes for 1988 resulted in differences between the 1988–1992 ASP Program efforts and those of earlier years. Prior to 1988, all LERs were reviewed by members of the project team. Starting in 1988, computerized searches of the SCSS data base identified those LERs that met the minimum selection criteria (e.g., failures in plant systems that provide protective functions for the plant for core damage-related initiating events). Hence, the project team evaluated only a portion of the LERs. While this subset is thought to include the most serious operational events, it is possible that some events that would normally be selected as precursors were missed because they were not included in the subset that resulted from the screening process. Section 2.1.1 provides further details of the selection criteria.

Model changes during this period included: (1) revising the LOOP recovery model, (2) the explicit modeling of PWR reactor coolant pump seal LOCA sequences, and (3) the reassignment of core vulnerability sequences on earlier trees to either success or core damage sequences. The net effect of the last change was a significant reduction in the complexity of the event trees, with little impact on the relative significance estimated for most precursors. NUREG/CR-4674, Vol. 9, provides additional details of these changes.[8]

1992–1993 Beginning with 1992, each preliminary analysis was transmitted to the responsible licensee for review and comment. As a result of comments received from reviews by the licensees, the NRC staff, and the NRC's independent contractor, credit for additional equipment and recovery procedures that were added by the plants was incorporated into the analyses of the precursors. Examples include the use of supplemental EDGs for station blackout mitigation, alternate systems for SG and RCS makeup, and venting in boiling-water reactors (BWRs). Appendix A of NUREG/CR-4674, Vol. 17, documents the changes incorporated over the years.[12]

1994–1997 The use of plant-class event trees and linked plant-specific fault trees in precursor analyses began in 1994. The use of linked fault trees allows the impact of individual component failures to be more precisely addressed; this could only be approximated in the earlier models. In addition, the method for calculating the probability for condition assessments (events in which components are unavailable for a period of time during which the initiating event could have occurred) was modified. These are known as the Revision 1 standardized, plant analysis risk (SPAR) models.

1998 The use of plant-class event trees and linked plant-specific fault trees in precursor analyses that began in 1994 was updated for the 1998 event analyses. The Revision 1 models were revised by incorporating changes that licensees made to their plants in response to licensing initiatives and to implement lessons learned as NRC staff experience with the models accumulated. The most significant changes in the models include: (1) expanding the treatment of emergency ac power; (2) adding plant-specific features identified in licensee responses to the Station Blackout Rule; (3) incorporating key plant features identified in the licensee's IPE submittal not previously considered; and (4) modifying the SPAR models to represent the interdependencies among the power conversion, condensate, and feedwater systems. The models were then revised to accommodate the comments generated by peer review and are now known as the Revision 2QA SPAR models.[23] Additional discussion concerning the current analysis methods is given in Appendix A.

Because of the differences in analysis methods, only limited observations are provided here. Refer to the 1982–1983 precursor report[3] for a discussion of observations for 1982–1983 results, the 1986 precursor report[6] for a discussion of observations for 1984–1986 results, and to the 1987–1997 reports[7-17] for the results for those years.

3.1 Tabulation of Precursors

The 1998 accident sequence precursors are listed in Tables 3.1–3.4. The following information is included on each table:

- Docket/LER number associated with the precursor (Event Identifier)
- Name of the plant where the precursor occurred (Plant)
- A brief description of the precursor (Description)

Table 3.1 At-Power Precursors Involving Initiating Events Sorted by Event Identifier

Plant	Event identifier	Description	Plant type	Event date	CCDP	Event type
Davis-Besse 1	LER 346/98-006	A tornado touchdown causes a complete (weather-related) LOOP	PWR	6/24/98	5.6×10^{-4}	LOOP
Davis-Besse 1	LER 346/98-011	Manual reactor trip while recovering from a component cooling system leak and de-energizing of safety-related bus D1 and nonsafety bus D2	PWR	10/14/98	1.4×10^{-5}	Transient

Table 3.2 At-Power Precursors Involving Unavailabilities Sorted by Event Identifier

Plant	Event identifier	Description	Plant type	Event date	CCDP	Importance (CCDP – CDP)	Event type
Big Rock Point	LER 155/98-001	Standby Liquid Control System unavailable for 13 years	BWR	7/14/98	6.9×10^{-5}	1.1×10^{-5}	Unavailability
Oconee 1	LER 269/98-004, -005	Calibration and calculational errors compromise emergency core cooling system (ECCS) transfer to emergency sump	PWR	2/12/98	2.0×10^{-5}	1.7×10^{-6}	Unavailability
Oconee 2	LER 269/98-004, -005	Calibration and calculational errors compromise ECCS transfer to emergency sump	PWR	2/12/98	2.0×10^{-5}	1.7×10^{-6}	Unavailability
Oconee 3	LER 269/98-004, -005	Calibration and calculational errors compromise ECCS transfer to emergency sump	PWR	2/15/98	1.9×10^{-5}	1.4×10^{-6}	Unavailability
Cook 2	LER 315/98-005	A postulated crack in a unit 2 main steam line may degrade the ability of the adjacent CCW pumps to perform their function	PWR	1/22/98	5.9×10^{-5}	2.7×10^{-6}	Unavailability
San Onofre 2	LER 361/98-003	Inoperable sump recirculation valve	PWR	2/5/98	4.6×10^{-5}	7.2×10^{-6}	Unavailability
Byron 1	LER 454/98-018	Long-term unavailability (18 d) of an EDG	PWR	9/12/98	9.0×10^{-6}	8.1×10^{-6}	Unavailability

Table 3.3 At-Power Precursors Involving Initiating Events Sorted by CCDP

CCDP	Plant	Plant type	Event identifier	Description	Event date	Event type
5.6×10^{-4}	Davis-Besse 1	PWR	LER 346/98-006	A tornado touchdown causes a complete (weather-related) LOOP	6/24/98	LOOP
1.4×10^{-5}	Davis-Besse 1	PWR	LER 346/98-011	Manual reactor trip while recovering from a component cooling system leak and de-energizing of safety-related bus D1 and nonsafety bus D2	10/14/98	TRANS

Table 3.4 At-Power Precursors Involving Unavailabilities Sorted by Importance

Importance (CCDP – CDP)	CCDP	Plant	Plant type	Event identifier	Description	Event date	Event type
1.1×10^{-5}	6.9×10^{-5}	Big Rock Point	BWR	LER 155/98-001	Standby Liquid Control System unavailable for 13 years	7/14/98	Unavailability
8.1×10^{-6}	9.0×10^{-6}	Byron 1	PWR	LER 454/98-018	Long-term unavailability (18 d) of an EDG	9/12/98	Unavailability
7.2×10^{-6}	4.6×10^{-5}	San Onofre 2	PWR	LER 361/98-003	Inoperable sump recirculation valve	2/5/98	Unavailability
2.7×10^{-6}	5.9×10^{-5}	Cook 2	PWR	LER 316/98-005	A postulated crack in a unit 2 main steam line may degrade the ability of the adjacent CCW pumps to perform their function	1/22/98	Unavailability
1.7×10^{-6}	2.0×10^{-5}	Oconee 1	PWR	LER 269/98-004, -005	Calibration and calculational errors compromise ECCS transfer to emergency sump	2/12/98	Unavailability
1.7×10^{-6}	2.0×10^{-5}	Oconee 2	PWR	LER 269/98-004, -005	Calibration and calculational errors compromise ECCS transfer to emergency sump	2/12/98	Unavailability
1.4×10^{-6}	1.9×10^{-5}	Oconee 3	PWR	LER 269/98-004, -005	Calibration and calculational errors compromise emergency core cooling system transfer to emergency sump	2/12/98	Unavailability

- Conditional probability of potential core damage associated with the precursor (CCDP)
- Date(s) of the precursor (Event Date)
- Plant type (Plant Type)
- Initiator associated with the precursor or unavailability if no initiator was involved (TRANS)

The tables are sorted as follows:

- Table 3.1—At-power precursors involving initiating events sorted by plant
- Table 3.2—At-power precursors involving unavailabilities sorted by plant
- Table 3.3—At-power precursors involving initiating events sorted by CCDP
- Table 3.4—At-power precursors involving unavailabilities sorted by importance (i.e., CCDP - CDP)

3.1.1 Potentially Significant Events That Were Impractical to Analyze

No potentially significant events were considered impractical to analyze for 1998. Typically, this event category includes events that are impractical to analyze because of lack of information or inability to reasonably model the event within a PRA framework, considering the level of detail typically available in PRA models. The basis for potentially significant events is documented in Appendix D.

3.1.2 Containment-Related Events

One containment-related event was identified for 1998 (Table 3.5). This event category includes losses of containment functions, such as containment cooling, containment spray, containment isolation (direct paths to the environment only), or hydrogen control. A description of the basis for events to be considered containment-related is given in Appendix E.

Table 3.5 Index of "Containment-Related" Events

Plant	Event description
Millstone 2	Feedwater valves may not be able to close fully on an isolation signal

3.1.3 "Interesting" Events

Two "interesting" events were identified for 1998 (Table 3.6). This event category includes events that were not selected as precursors but that provided insight into unusual failure modes with the potential to compromise continued core cooling. Descriptions of these events are located in Appendix F.

Table 3.6 Index of "Interesting" Events

Plant	Event description
Point Beach 1	Loss of the station auxiliary transformer while at power
WNP 2	ECCS pump room flooding because of a fire protection system pipe break

3.2 Insights

As described previously, differences in the ASP models and the analysis methods from year to year preclude a direct comparison between the number of precursors identified for different calendar years. In particular, the CCDPs estimated for some 1992–1998 precursors are lower than for equivalent precursors in earlier years because supplemental and plant-specific mitigating systems beyond those included in the pre-1992 ASP models were incorporated into the analyses. In addition, new modeling techniques were adopted for the analysis of the 1994–1998 precursors (e.g., plant-specific fault trees).

A review of the analyses for all 9 precursors for 1998 and a comparison with analyses for previous years revealed the following insights and trends.

3.2.1 Number of Precursors Identified

The total number of precursors identified for 1998 (9) is about double the number from 1997 (5) but appears to be about the average of the post-1992 years (Fig. 3.1). Some of this statistically significant downward trend (p-value = 0.0001) over the last 10 years may be because of the differences in the ASP analysis approach, including sending the preliminary analyses to the licensees for review and comment.

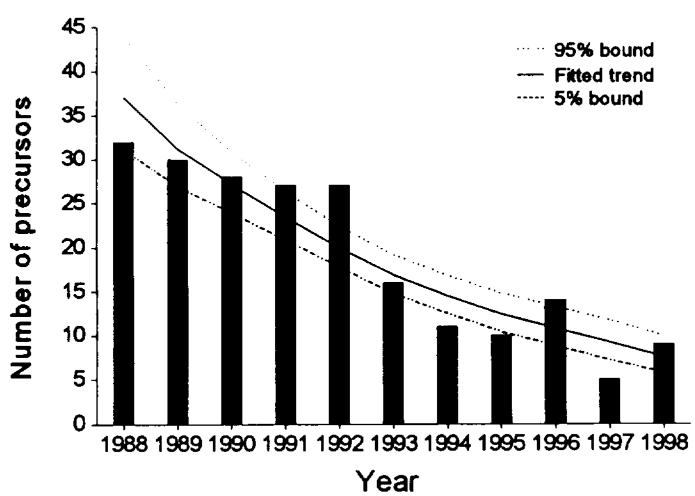

Fig. 3.1 Total number of precursors by year.

Historically, the percentage of precursors is evenly split between unavailabilities (48%) and initiating events (52%) (Figs. 3.2 and 3.3, respectively). The initiating events of interest include (with their 10-year average in parentheses) general plant transients (27%), LOOPs (17%), LOFW events (4%), LOCAs (2%), and steam generator tube ruptures (SGTRs) (2%) (Fig. 3.4). (Important precursors are addressed in Sect. 3.2.2.) Contributing to the statistically significant downward trend (p-value = 0.0001) in the number of initiating events is the reduction in the number of safety system actuations and the number of automatic scrams; both have decreased by a factor of 4 over the last 10 years (Ref. 24). Because unavailability assessments include contributions from more than one initiator type, it is difficult to categorize these events.

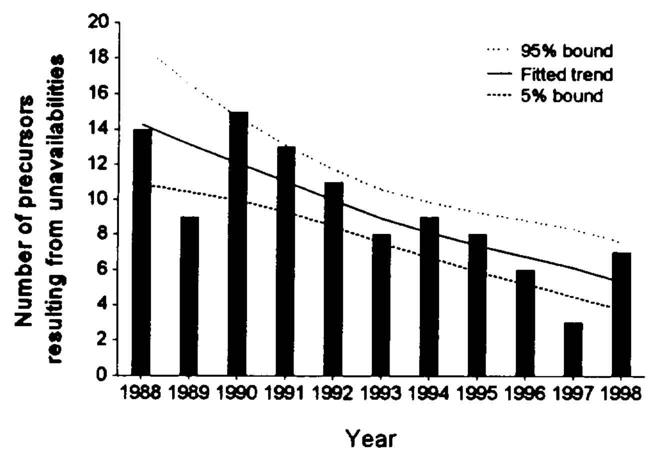

Fig. 3.2 Number of precursors resulting from unavailabilities.

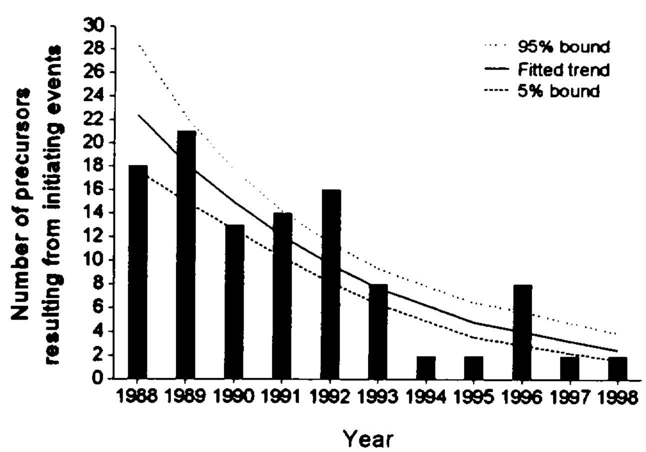

Fig. 3.3 Number of precursors resulting from initiating events.

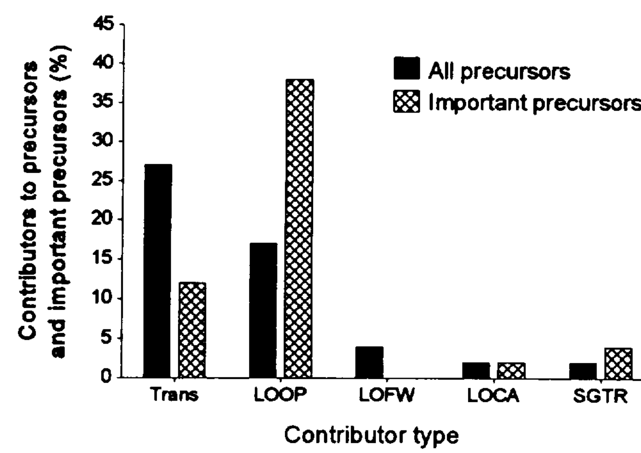

Fig. 3.4 Contributors to precursors resulting from initiating events.

Reducing the number of transients as well as the number of challenges to safety systems will directly affect the number of precursors. As shown in Fig. 3.5 and Table 3.7, about 55% of all precursors involve some type of equipment failure, 41% human error, 18% had a safety-related component out of service for maintenance, and 7% were weather-induced.

Table 3.7 Failure modes of precursors

Failure mode (%)	Contributor to failure mode (%)[a]
Equipment failures (55%)	
valves	25
breakers	15
EDGs	15
pumps	16
transformers	10
other	18
Human errors (41%)	
maintenance	48
design	29
operator	12
procedure	10
other	1
Component out of service (18%)	
EDG	40
other electric power component	10
HPI / LPI	38
AFW / EFW	12
Weather-induced failures (7%)	
thunderstorm	38
cold/ice	38
hurricane	16
fire	8

[a]These percentages sum to more than 100% because 23% of the events had more than one contributor. For example, ~10% of the precursors had a safety-related component out of service coincident with an equipment failure.

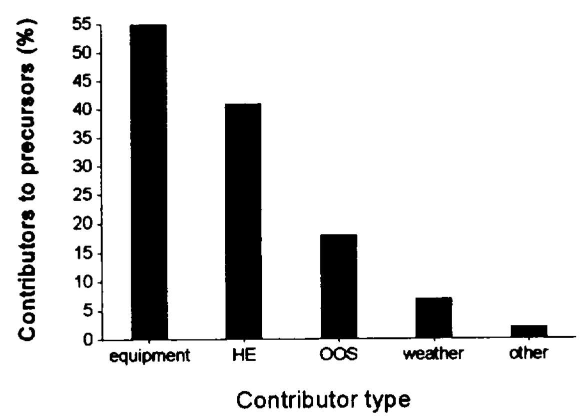

Fig. 3.5 Contributors to precursors. (HE is human error, OOS is out of service)

The nine precursors in 1998 affected eight units (i.e., two of the precursors occurred at one unit). The distribution of precursors as a function of CCDP for 1988 through 1998 is shown in Table 3.8 and in Figs. 3.6–3.9.

Table 3.8 Number of Precursors by Year

Year[a]	No. of reactor years[b]	$10^{-3} \leq$ CCDP < 1 or Importance[c]	$10^{-4} \leq$ CCDP $\leq 10^{-3}$ or Importance	$10^{-5} \leq$ CCDP $\leq 10^{-4}$ or Importance	$10^{-6} \leq$ CCDP $\leq 10^{-5}$ or Importance	Total no. of precursors
1988	107.1	0	7	14	11	32
1989	109.0	0	7	11	12	30
1990	110.5	0	6	11	11	28
1991	111.0	1	12	8	6	27
1992	110.4	0	7	7	13	27
1993	108.7	0	4	7	5	16
1994	109.0	1	1	5	4	11
1995	109.0	0	0	7	3	10
1996	110.1	1	2	4	7	14
1997	109.2	0	0	2	3	5
1998	104.5	0	1	2	6	9

[a]In 1988, the ASP Program began using computerized searches to identify LERs that meet minimum selection criteria, revised the LOOP recovery model, and explicitly modeled PWR seal LOCA sequences. In 1992, additional equipment and procedures were incorporated into the plant models. In 1994, the project began using plant-class event trees and plant-specific fault trees. Consequently, a direct comparison of results is not possible without substantial effort to reconcile analysis differences.

[b]The number of reactor years, which is based on the total number of operating hours, has been dropping since 1997 because a number of plants are shutting down permanently.

[c]The measure of significance for the unavailability assessments is the importance (see Sect. 2.2).

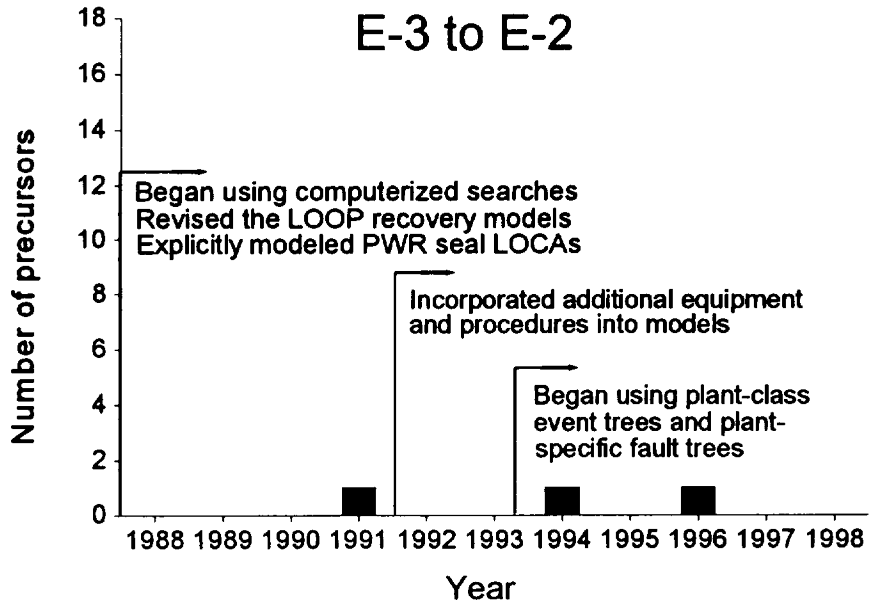

Fig. 3.6. CCDP results by year for 10^{-3} to 10^{-2}.

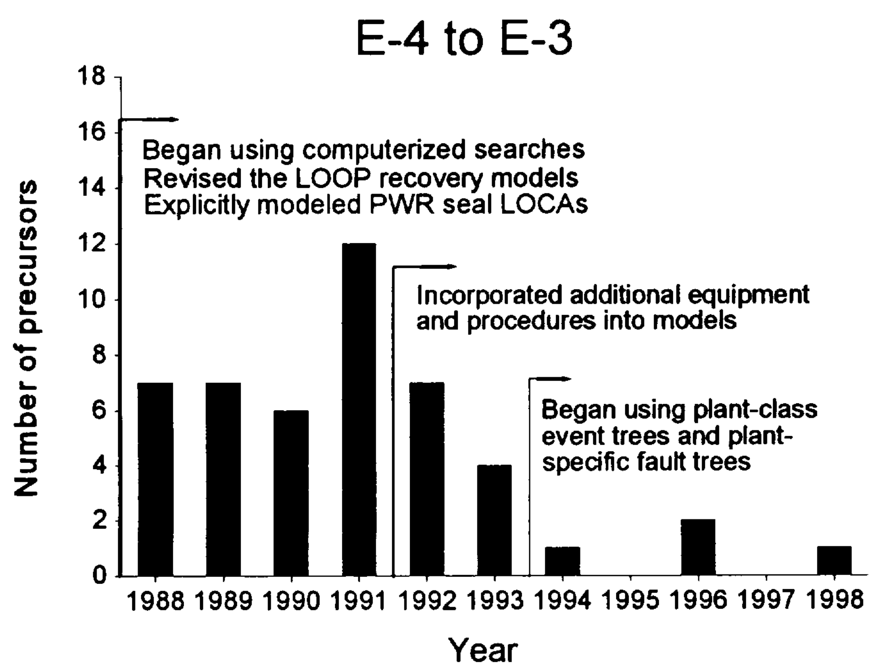

Fig. 3.7. CCDP results by year for 10^{-4} to 10^{-3}.

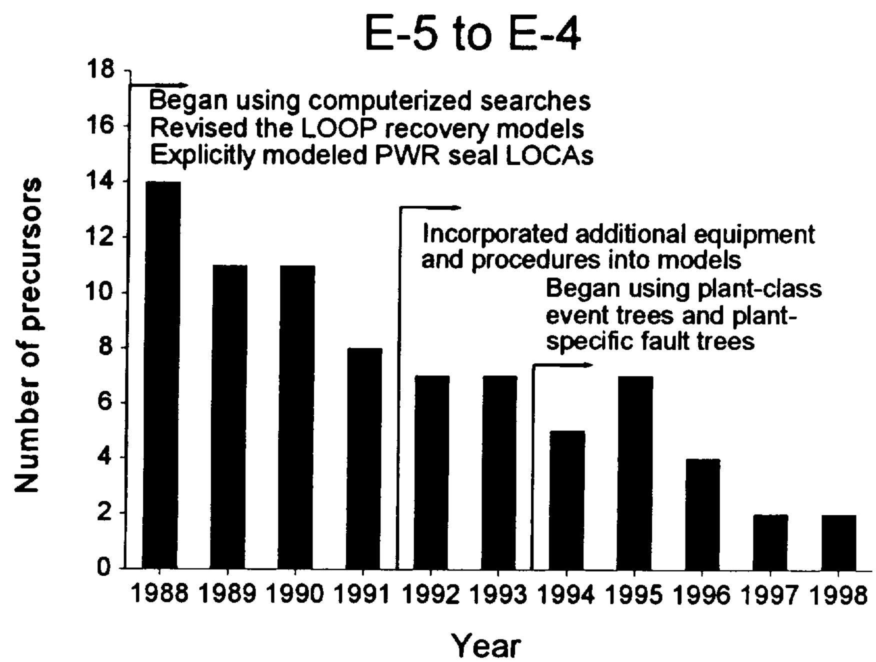

Fig. 3.8. CCDP results by year for 10^{-5} to 10^{-4}.

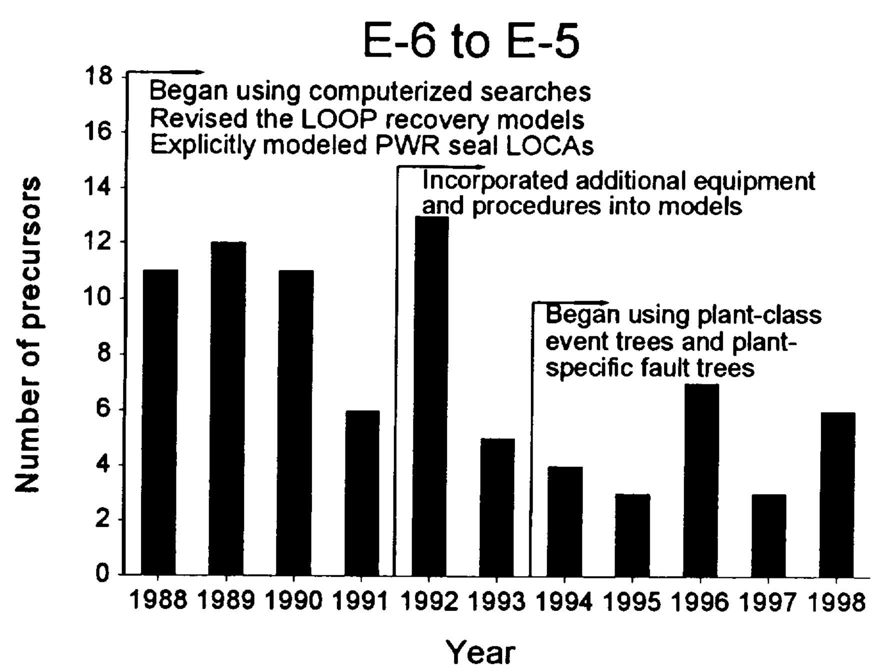

Fig. 3.9. CCDP results by year for 10^{-6} to 10^{-5}.

3.2.2 Important Precursors

Precursors with CCDPs ≥ 10^{-4} have traditionally been considered important in the ASP Program. For 1998, one precursor with a CCDP ≥ 10^{-4} was identified—a tornado touchdown at Davis-Besse. The Davis-Besse Plant was in Mode 1 at 99% power at ~2040 on June 24, 1998, when a severe thunderstorm cell moved into the area. Several minutes later, a tornado touched down either near or in the switchyard, damaging switchyard equipment and causing a complete loss of offsite power (LOOP). Before the touchdown of the tornado, the senior reactor operator (SRO) instructed the operators to start the EDGs from the control room because of the severe weather conditions. Although EDG 2 started successfully, EDG 1 failed to start. Operators then attempted to start EDG 1 locally; EDG 1 started successfully. Several minutes later, a tornado touched down in or near the switchyard, causing a complete LOOP. The LOOP caused the turbine control valves to close in response to a load rejection by the main generator. The reactor protection system (RPS) initiated a reactor trip on high reactor coolant system (RCS) pressure. At 2118 on June 24, the licensee declared an Alert as prescribed by the plant's emergency procedures. On June 25, 1998, at ~2330, following the restoration of the Ohio Edison offsite line, the EDGs were shut down. The Alert was subsequently downgraded to an Unusual Event at 0200 on June 26, 1998, because personnel had restored one offsite power source. The Unusual Event was terminated at 1405 on June 26, after personnel had restored a second offsite power source.[27,28] The conditional core damage probability (CCDP) for this event is 5.6×10^{-4}. This event is discussed in detail in Appendix B.

Over the last 10 years, about 25% of the precursors were considered to be important. Similar to all precursors, the number of important precursors has a statistically significant downward trend (p-value = 0.0001) (Fig. 3.10), with the precursors being evenly split between initiating events (56%) and unavailabilities (44%). Unlike all precursors, the initiating events of interest for important precursors (CCDP or importance ≥ 10^{-4}) are dominated by LOOP events (Fig. 3.4). The longer the LOOP lasts, the higher the CCDP. Also, the unavailablility of an EDG (or EDGs) during a LOOP results in a larger CCDP value. Because unavailability assessments include contributions from more than one initiator type, it is difficult to categorize these events.

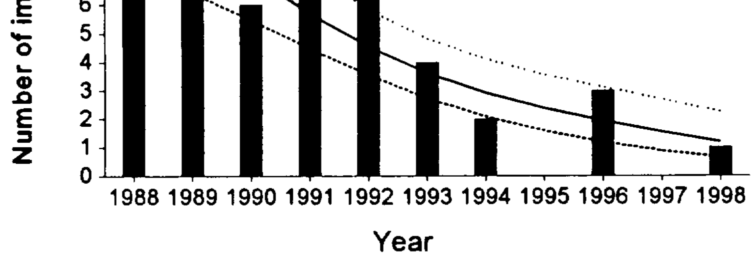

Fig. 3.10 Number of important precursors (i.e., CCDP or importance ≥ 10^{-4}).

Precursors with a CCDP or importance ≥ 10^{-3} occur rather infrequently and are unique events (i.e., no pattern for causes or nature of failures) (Fig. 3.3). Those precursors with a CCDP ≥ 10^{-3} that have occurred since 1988 are listed in Table 3.9.

Table 3.9 Precursors with a CCDP ≥ 10^{-3}

Year	Plant	Description	Event type
1991	Harris 1	High-head safety injection unavailable because two relief valves had failed from the effects of water hammer	Unavailability
1994	Wolf Creek	RCS blowdown to the RWST during hot shutdown because of an inappropriate alignment to the residual heat removal system	Initiating event
1996	Catawba 2	Ground faults on 2A and 2B main transformers caused a plant-centered LOOP; EDG B was out of service for maintenance	Initiating event

3.2.3 LOOP-Related Precursors

Of the two LOOP events that occurred in 1998, only one was classified as a precursor (Fig. 3.11)—a tornado touchdown causing a complete (weather-related) LOOP at Davis-Besse. (The other LOOP occurred at Braidwood . The CCDP associated with this event did not exceed the precursor threshold, and the event did not meet the criteria for an "interesting" event.). Plant-centered LOOPs are the most frequent and are typically caused by equipment faults (67%) and, to a lesser extent, human errors (22%). During 5 of the 27 plant-centered LOOP-related precursors that occurred during the last 10 years, an EDG (4 times) or a vital bus (1 time) was out of service for a test or maintenance. Typically, severe weather-related LOOPs have the longest duration. An extreme example is the weather-induced LOOP caused by Hurricane Andrew in 1992 at Turkey Point 3 and 4 that lasted over 6.5 days. Grid-based LOOPs are rare—the last grid-based LOOP event occurred in 1989 at Summer. The ASP results for LOOPs are comparable with those provided in NUREG/CR-5496.

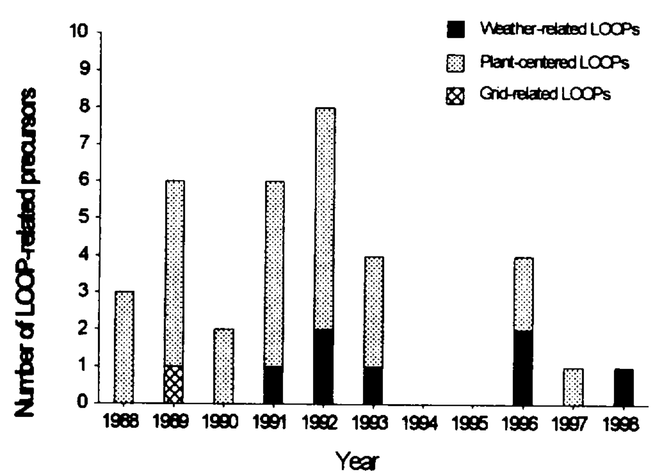

Fig. 3.11 Number of LOOP-related precursors per year.

3.2.4 Consistency with PRAs/IPEs

Most of the precursors are consistent with the failure combinations identified in PRAs/IPEs. A review of the last several years (1994–1998) shows that several precursors involved event initiators or conditions not typically modeled in PRAs or IPEs (Table 3.10).

Table 3.10 Precursors not Typically Modeled in PRAs or IPEs

Year	Plant(s)	Event description
1994	Wolf Creek	Blowdown of the RCS to the refueling water storage tank (RWST) during hot shutdown
1996	Wolf Creek	Reactor trip with the loss of one train of emergency service water due to the formation of frazil ice on the circulating water traveling screens and the unavailability of the turbine-driven auxiliary feedwater (AFW) pump
1996	LaSalle 1 and 2	Fouling of the cooling water systems due to concrete sealant injected into the service water tunnel
1996	Haddam Neck	Inadequate residual heat removal pump net positive suction head following a large- or medium-break LOCA
1998	Oconee 1, 2, and 3	Incorrect calibration of the borated water storage tank (BWST) level instruments resulted in a situation where the emergency operating procedure (EOP) requirements for BWST-to-reactor building emergency sump (RBES) transfer would never have been met; operators would be working outside the EOP

3.2.5 BWR vs PWR

Historically, the number of precursors occurring at BWRs (Fig. 3.12) has been disproportionately less than at PWRs (Fig. 3.13). Both figures show a statistically significant decreasing trend (p-value = 0.0001 for Figs. 3.12 and 3.13). In the last several years, the percentage of precursors occurring at BWRs appears to be decreasing. Only one of the precursors (11%) for 1998 occurred at a BWR—the unavailability of the standby liquid control system at Big Rock Point for up to 15 years because of corrosion. Reference 24, NUREG-1560, indicates that BWR core damage frequencies estimated in the IPEs were less than the frequencies estimated for PWRs in most cases. This difference was attributed to the larger number of injection systems and the capability to more easily depressurize the primary system to allow use of low-pressure injection systems. This may explain, in part, the smaller number of BWR precursors than would be indicated by the fraction of units that are BWRs.

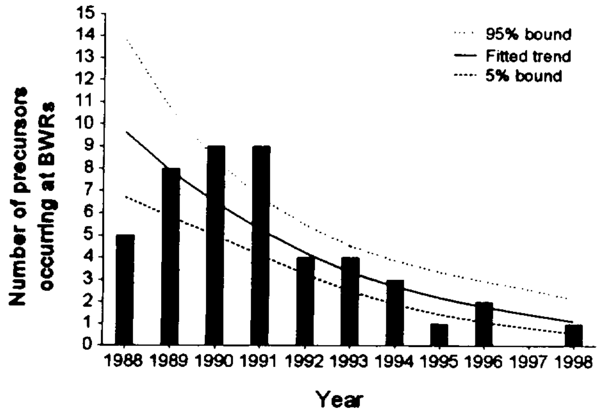

Fig. 3.12 Number of precursors occurring at BWRs.

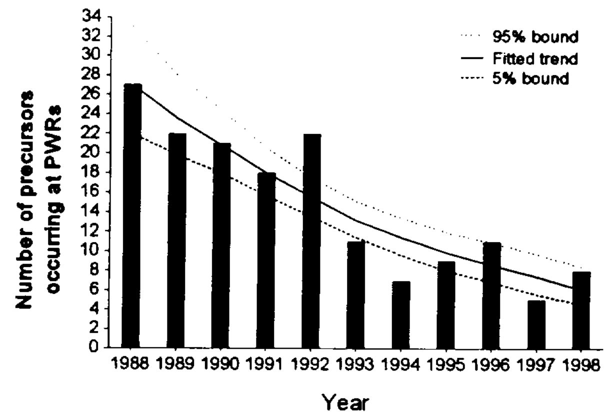

Fig. 3.13 Number of precursors occurring at PWRs.

3.2.6 Multiunit Site vs Single Unit Site

Sixty-seventy percent (6 out of 9) of the 1998 precursors occurred at multiunit sites (Fig. 3.14); the percentage of units located at multiunit sites is about 71%. The 10-year average for percentage of precursors occurring at multiunit sites is 65%. Therefore, there does not appear to be any benefit or detriment associated with a multiunit site with respect to the overall occurrence rate of precursors. However, several events that occurred during 1998 would have been above the cut-off criteria for a precursor if the event occurred at a single-unit site. Because these events occurred at multi-unit sites and procedures exist to cross-tie systems between units (e.g., electrical, feedwater), credit was given for cross-tie capabilities. Hence, the ability to cross-tie systems resulted in a CCDP (or importance) below the precursor cut-off value of 1.0×10^{-6}.

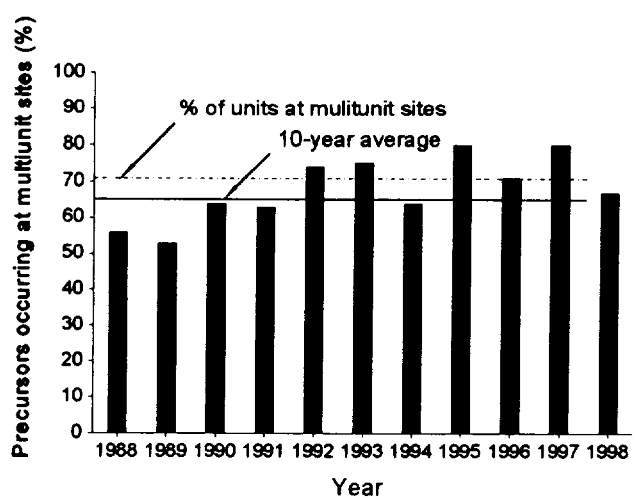

Fig. 3.14 Percentage of precursors that occurred at multiunit sites.

3.2.7 Electric Power-Related Events

Electric power-related events and conditions continue to be a significant fraction of the precursors (3 of the 9 precursors in 1998 involved problems with electrical equipment). This is less than in previous years (1988–1997), for which about 46% of the precursors involved electric-power-related issues (Fig. 3.15). The number of electric-power related precursors shows a statistically significant decreasing trend (p-value = 0.0001). As shown in Fig. 3.16, for the last 10 years, 26% of the electric-power-related events involved human errors (69% were because of maintenance errors), 24% involved EDG-related failures, 18% involved breaker failures, 17% involved electrical equipment out of service, 15% involved transformer failures, and 7% were weather-related events.

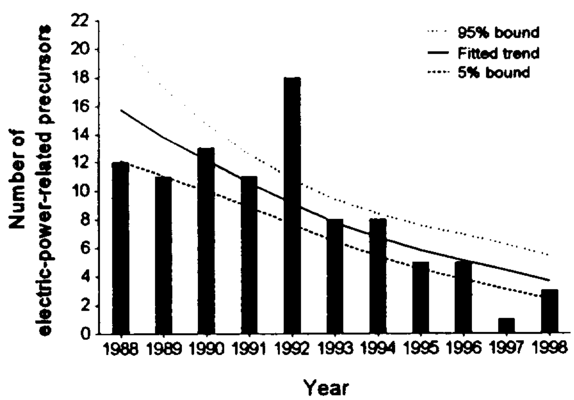

Fig. 3.15 Number of electric-power-related precursors.

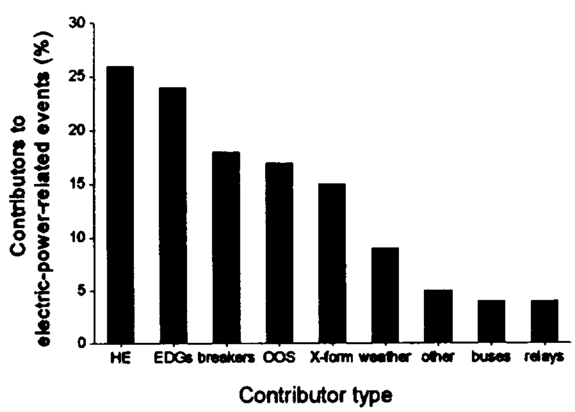

Fig. 3.16 Contributors to electric-power-related precursors. (HE is human error, EDG is emergency diesel generator, OOS is out of service, and X-form is transformer)

3.2.8 Feedwater-Related Events

Precursors involving the degradation of auxiliary feedwater (AFW)/emergency feedwater (EFW) are typically frequent contributors to the number of precursors. One of the 1998 precursors involved problems with AFW/EFW—one AFW pump was out of service for testing (19 min) and another AFW pump was unavailable when the safety-related bus deenergized at Davis-Besse. Figure 3.17 shows the number of AFW- and EFW-related precursors associated with unexpected demands. Figure 3.17 also shows the fitted trend with the associated uncertainty bounds on the mean value. The decreasing trend is statistically significant (p-value = 0.0001) and was estimated using a log-linear model (Ref. 25) with reactor years as an independent variable. The decrease in the number of AFW-related precursors is primarily the result of the decrease in the number of unexpected AFW system demands related to trips in the later years of the time period. Over the last 10 years (Fig. 3.18), failures in the AFW/EFW systems have occurred because of pump failures (43%), valve failures (20%), human errors (17%) (60% were because of maintenance errors), or equipment out of service for testing or maintenance at the time of the demand (17%). These percentages sum to more than 100% because 1 of the 30 AFW / EFW-related precursors had two contributors—a component out of service coincident with a pump failure.

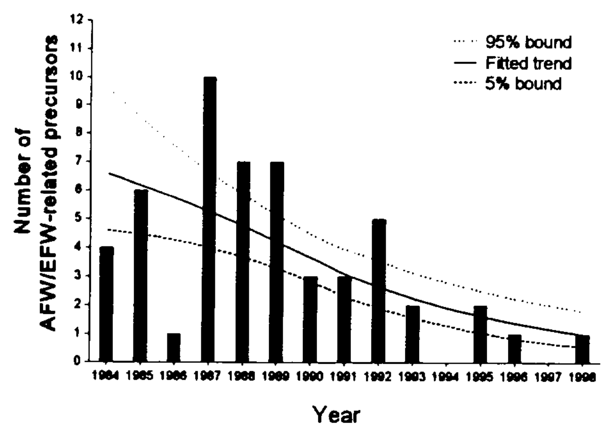

Fig. 3.17 Number of AFW / EFW-related precursors associated with unexpected demands.

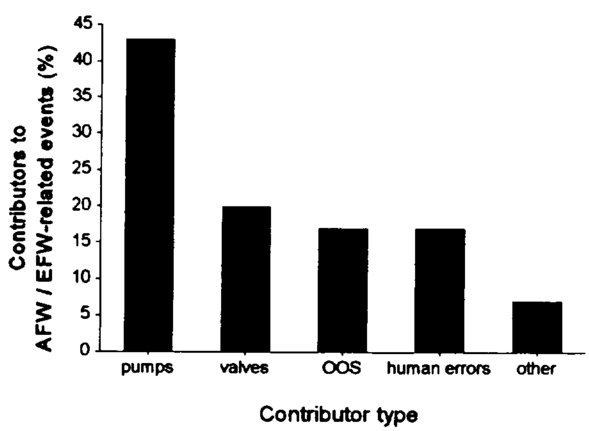

Fig. 3.18 Contributors to AFW / EFW system failures. (OOS is out of service)

3.2.9 Safety-Related High / Low Pressure Systems

Historically, the number of precursors involving the failure of at least one train of a high-pressure system is significantly higher than for low-pressure systems (Fig. 3.19). The decreasing trend is statistically significant (p-value = 0.0001). The decrease is primarily the result of the decrease in the number of unexpected system demands related to trips and safety-system actuations in the later years of the period (i.e., the number of transients, LOOPs, etc. has been decreasing). Credit for containment venting for BWRs was added to the BWR models in 1994, but because BWRs contribute only 10–20% of all precursors, this model change does not account for the downward trend in high-pressure system failures and degradations. Over the last 10 years (Fig. 3.20), failures in the high-pressure/low-pressure injection (HPI/LPI)/recirculation systems have occurred because of valve failures (35%), equipment out of service at the time of the demand (33%), human errors (19%) (38% were because of maintenance errors), or pump failures (9%). These percentages sum to more than 100% because 19% of these events had more than one contributor. For example, ~14% of the HPI/LPI-related precursors had a safety-related component out of service coincident with an equipment failure.

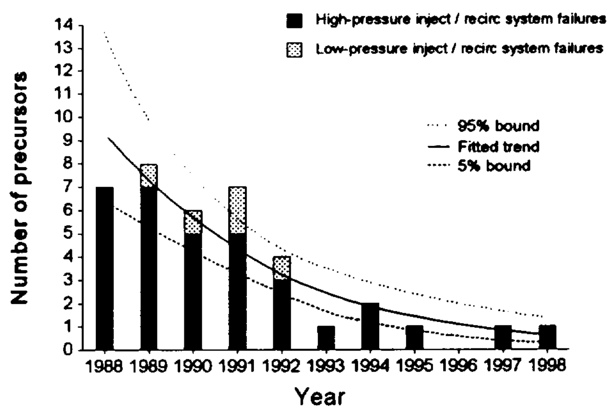

Fig. 3.19 Number of precursors involving *failed* high-pressure / low-pressure recirculation / injection.

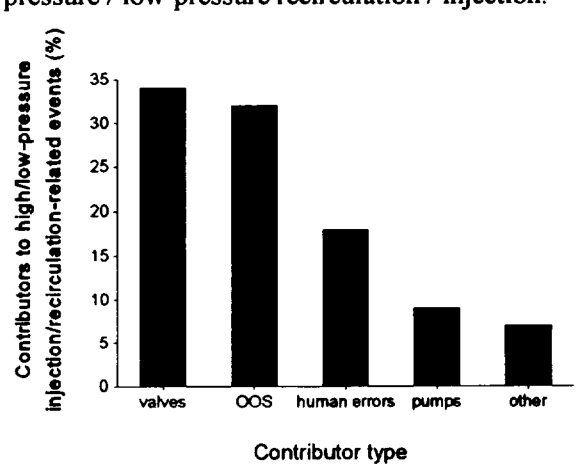

Fig. 3.20 Contributors to high-pressure / low-pressure recirculation / injection system failures. (OOS is out of service)

3.3 Conclusion

The total number of precursors identified for 1998 (9) is about double the number from 1997 (5) but appears to be about the average of the post-1992 years. Some of this downward trend over the last 10 years is attributed to the differences in the ASP analysis approach. Also contributing to this downward trend are the reduction in the number of safety system actuations and the number of automatic scrams; both have decreased by a factor of 4 over the last 10 years. About 55% of the precursors involved equipment failures. In addition to equipment failures, one or more of the following conditions have been present: human error (41%), a safety-related component out of service for maintenance (18%), weather-induced failures (7%).

4. Glossary

Accident. An unexpected event (frequently caused by equipment failure or some misoperation as the result of human error) that has undesirable consequences.

Accident sequence precursor. An historically observed element or condition in a postulated sequence of events leading to some undesirable consequence. For purposes of the ASP Program, the undesirable consequence is usually severe core damage. The identification of an operational event as an accident sequence precursor does not of itself imply that a significant potential for severe core damage existed. It does mean that at least one of a series of protective features designed to prevent core damage was compromised. The likelihood of severe core damage given the occurrence of an accident sequence precursor depends on the effectiveness of the remaining protective features and, in the case of precursors that do not include initiating events, the probability of such an initiator.

Availability. The characteristic of an item expressed by the probability that it will be operational on demand or at a randomly selected future instant in time. Availability is the complement of unavailability.

Base probability. The nominal failure probability for the basic event and is given in the ASP linked event tree-fault tree model for the plant.

Common-cause failures. Multiple failures attributable to a common cause.

Components. Items from which equipment trains and/or systems are assembled (e.g., pumps, pipes, valves, and vessels).

Conditional probability. The probability of an outcome given certain conditions.

Core damage. See *Severe core damage.*

Core-melt accident. An event in a nuclear power plant in which core materials melt.

Degraded system. A system with failed components that still meets minimum operability standards.

Demand. A test or an operating condition that requires the availability of a component or a system. In the ASP Program, a demand includes actuations required during testing and because of initiating events. One demand is assumed to consist of the actuation of all redundant components in a system, even if these were actuated sequentially (as is typical in testing multiple-train systems).

Dependent failure. A failure in which the likelihood of failure is influenced by the failure of other items. Common-cause failures are dependent failures.

Dominant sequence. The sequence in a set of sequences that has the highest probability of leading to a common end state.

Emergency core cooling systems. Systems that provide for removal of heat from a reactor following either a loss of normal heat removal capability or a LOCA.

Engineered safety features. Equipment and/or systems (other than reactor trip or those used only for normal operation) designed to prevent, limit, or mitigate the release of radioactive material.

Event. An abnormal occurrence that is typically in violation of a plant's Technical Specifications.

Event sequence. A particular path on an event tree.

Event tree. A logic model that represents existing dependencies and combinations of actions required to achieve defined end states following an initiating event. Event trees are typically used to model potential plant response to an initiating event on a system or functional level.

Failure. The inability to perform a required function. In this study, a failure was considered to have occurred if some component or system performed at a level below its required minimum performance level without human intervention. The likelihood of recovery was separately accounted for in the analysis.

Failure probability. The long-term frequency of occurrence of failures of a component, system, or combination of systems to operate at a specified performance level when required. In this study, failure includes both failure to start and failure to operate once started.

Failure rate. The expected number of failures of a given type, per item, in a given time interval (e.g., capacitor short-circuit failures per million capacitor hours).

Fault tree. A fault tree is a graphical representation of the logical combinations of basic events that can lead to an undesired event, such as a system failure.

Front-line system. A system that directly provides a mitigative function included on the event trees used to model sequences to an undesired end state, in contrast to a support system, which is required for operability of other systems.

Immediately detectable. A term used to describe a failure resulting in a plant response that is apparent at the time of the failure.

Initial criticality. The date on which a plant goes critical for the first time in first-cycle operation.

Initiating event. An event that starts a transient response in the operating plant systems. In the ASP Program, the concern is with those initiating events that could lead to severe core damage.

Licensee event reports. Those reports described in 10 CFR 50.73 and submitted to NRC by utilities who operate nuclear plants. LERs describe abnormal operating occurrences that generally involve violations of the plants' Technical Specifications.

Multiple failure events. Events in which more than one failure occurs. These may involve independent or dependent failures.

Operational event. An event that occurs in a plant and generally constitutes a reportable occurrence under 10 CFR 50.73 as an LER.

Postulated event. An event that may happen at some time in the course of a plant's operation.

Potential severe core damage. A plant operating condition in which, following an initiating event, one or more protective functions fail to meet minimum operability requirements over a period sufficiently long that core damage could occur. This condition has been called in other studies "core melt," "core damage," and "severe core damage," even though actual core damage may not result unless further degradation of mitigation functions occurs.

Precursor. See *Accident sequence precursor.*

Reactor years. The accumulated total number of years of reactor operation.

Redundant equipment or system. A system or some equipment that duplicates the essential function of another system or other equipment to the extent that either may perform the required function regardless of the state of operation or failure of the other.

Reliability. The characteristic of an item expressed by the probability that it will perform a required function under stated conditions for a stated period of time.

Risk. A measure of the frequency and severity of undesired effects.

Sensitivity analysis. An analysis that determines the variation of a given function caused by changes in one or more parameters about a selected reference value.

Severe core damage. The result of an event in which inadequate core cooling was provided, resulting in damage to the reactor core. See *Potential severe core damage.*

Technical Specifications. A set of safety-related limits on process variables, control system settings, safety system settings, and the performance levels of equipment that are included as conditions of an operating license.

Unavailability. The probability that an item or system will not be operational at a future instant in time. Unavailability may be a result of the item being tested or may occur as a result of malfunctions. Unavailability is the complement of availability.

Unit. A nuclear steam supply system, its associated turbine generator, auxiliaries, and engineered safety features.

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27. LER 346/98-011, "Manual Reactor Trip Due to Component Cooling Water System Leak." November 13, 1998.

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*Available for purchase from the National Technical Information Service, Springfield, Virginia 22161.

Appendix A:

ASP Calculational Methodology

A.1 Introduction

This appendix describes the approach used in the Accident Sequence Precursor (ASP) Program to estimate the significance of an operational event. The process used to screen the operational event data base for potential precursors and the characteristics of events ultimately selected as precursors are described in Chap. 2 of this report.

The ASP Program performs retrospective analyses of operating experience. These analyses require that certain methodological assumptions be made to estimate the risk significance of an event. If one assumes, following an operational event in which core cooling was successful, that components observed failed were "failed" with probability 1.0 and components that functioned successfully were "successful" with probability 1.0, then one can conclude that the risk of core damage was zero and that the only potential sequence was the combination of events that occurred. To avoid such trivial results, the status of certain components must be considered latent. In the ASP Program, this latency is associated with components that operated successfully; these components are considered to have been capable of failing during the operational event.

Quantifying the significance of the events identified as precursors involves determining a conditional probability of subsequent core damage given the failures and other undesirable conditions (such as an initiating event or an unexpected relief valve challenge) that were observed during an operational event. The effect of a precursor on basic events in the core damage models is assessed by reviewing the operational event specifics against plant design and operating information and then translating the results of the review into a revised model for the plant that reflects the observed failures. The precursor's significance is then estimated by calculating a conditional probability of core damage given the observed failures. The probabilities of components observed to operate successfully or that were not challenged during the event are not modified. The conditional probability calculated in this way is useful in ranking because it provides an estimate of the measure of protection against core damage remaining once the observed failures have occurred.

The accident sequence models used to estimate the significance of 1997 precursors consist of fault tree models that depict the logical combination of component failures (basic events) that would result in failure of each system that provides protection against core damage. The fault trees are linked together in a logical structure based on event trees that describe potential combinations of system successes and failures that would result in core damage following postulated initiating events. The resulting Boolean equations, when reduced to their simplest form, consist of a series of combinations of basic events (cut sets), any of which would result in core damage if all of the basic events in the cut set occurred. A detailed description of the use of linked fault trees in probabilistic risk assessment (PRA) analysis is included in Ref. 1. The current ASP models are described in NUREG/CR-4674, Vol. 21 (i.e., the ASP Program's 1994 status report). These models are constructed and solved using the SAPHIRE suite of PRA software.[2]

A.2 Types of Events Analyzed

Two different types of events are addressed in precursor quantitative analysis. In the first, an initiating event such as a loss of offsite power (LOOP) or small-break loss-of-coolant accident (SLOCA) occurs as a part of the precursor. The probability of core damage for this type of event is calculated based on the required plant response to the particular initiating event and other failures that may have occurred at the same time. The assessment of an observed initiating event is referred to as an Initiating Event Assessment.

The second type of event involves a failure condition that existed over a period of time during which an initiating event could have occurred, but did not occur. The probability of core damage is calculated based on the required plant response to a set of postulated initiating events, considering the failures that were observed. Unlike an initiating event assessment, where a probability of 1.0 is used for the observed initiating event, each initiating event is assumed to occur with a probability based on the initiating event frequency and the failure duration. The assessment of failed equipment over a period of time is referred to as a Condition Assessment.

A.3 Modification of Basic Event Probabilities to Reflect Observed Failures

The ASP models describe sequences to core damage in terms of combinations of basic events. Each basic event typically represents the failure of a particular component or group of components in a system at a plant, an occurrence such as a relief valve lift, or the failure of an operator to perform a required action. Failures observed during an operational event must be represented in a model in terms of changes to one or more of the basic events.

If a failed component is included as a basic event in a model, the failure can be reflected by setting its basic event probability to 1.0 (failed). In actuality, such a basic event must be set to the logical state "true" if a new minimum set of cut sets reflecting the conditional state of the plant is to be generated.[a]

In addition to revising the basic events associated with failed components, basic events related to the common-cause failure of similar components may also have to be revised to reflect the observed failures. If the failure could also have occurred in other similar components at the same time, then the common-cause failure probability is increased to represent this likelihood. If the failure could not simultaneously occur in other components (e.g., if a component was removed from service for preventive maintenance), then the common-cause failure probability is also revised, but only to reflect the "removal" of the unavailable component from the model. The Multiple Greek Letter (MGL) method is used to quantify the common-cause failure basic events (see Ref. 3 for a description of the MGL model).

If a failed component is not specifically included as a basic event in a model, then the failure is addressed by setting basic events impacted by the failure to "failed" (logical state "true"). For example, support systems are not completely developed in the current ASP models. A breaker failure that results in the loss of power to a group of components would be represented by setting the basic events for each component in the group to "true."

Occasionally, a precursor occurs that cannot be modeled by modifying existing basic event probabilities. In such a case, the model is revised as necessary to address the event, typically by adding basic events to a fault tree or by addressing an unusual initiating event through the use of an additional event tree.

[a]Practical considerations in the solution of large linked fault trees, primarily the use of the Delete Term process to solve sequences involving system success, also require failed basic events to be represented as "true" if correct sequence probabilities are to be calculated.

A.4 Recovery from Observed Failures

The probability of failing to recover from the failure is estimated using a time-reliability correlation (TRC) model. The available time to respond, the underlying type of response (rule- or knowledge-based), and whether unusual conflict or burden would exist in response to an actual initiating event are addressed when developing an estimate of the operator (crew) error probability. The basic model structure is described in Ref. 4. The probability of in-control room operator error is described using a lognormal distribution with the following parameters:

Type of action	Median	Error factor
Rule-based, unburdened	2	3.2
Rule-based, burdened	2	6.4
Knowledge-based, unburdened	4	3.2
Knowledge-based, burdened	4	6.4

For an available time t_{avail}, the probability of operator error is estimated as

$$1 - \Phi[(\ln t_{avail} - m) / \sigma],$$

where Φ is the normal distribution, $m = \ln(\text{median})$, and $\sigma = \ln(\text{error factor})/1.645$.

The potential for recovery from observed failures outside the control room considers the time available for response and the nature of the failures (which prescribe the repair time).

Note that the actual likelihood of failing to recover from an event at a particular plant is difficult to assess and may vary substantially from values estimated using this approach. This difficulty is demonstrated in the genuine differences in opinion among analysts, operations and maintenance personnel, etc., concerning the likelihood of recovering specific failures (typically observed during testing) within a time period that would prevent core damage following an actual initiating event.

A.5 Conditional Probability Associated with Each Precursor

As described previously in this appendix, the calculation process for each precursor involves a determination of initiators that must be modeled, plus any modifications to system probabilities necessitated by failures observed in an operational event. Once the basic event probabilities that reflect the conditions of the precursor are established, the sequences leading to core damage are calculated to estimate the conditional probability for the precursor. This calculational process is summarized in Table A.1.

Several simplified examples that illustrate the basics of the precursor calculational process follow. The intent of the examples is not to describe a detailed precursor analysis, but instead to provide a basic understanding of the process. The examples are presented in terms of event tree branch probabilities that are multiplied to calculate sequence probabilities. Readers familiar with the use of linked fault trees for PRA can readily extrapolate the process illustrated in the example calculations to analyses employing fault trees.

The hypothetical core damage model for these examples, shown in Fig. A.1, consists of initiator I and four single-component systems that provide protection against core damage: systems A, B, C, and D. In Figure A.1, the up branch represents success, and the down branch represents failure for each of the systems. (In an accident sequence model for an actual reactor plant, the fault tree logic for each system could involve hundreds of components, and thousands of cut sets could be required to represent the basic event failure combinations that constitute the core damage sequences.) Three sequences result in core damage if completed: sequence 3 [I /A ("/" represents system success) C D], sequence 6 (I A /B C D), and sequence 7 (I A B). In a conventional PRA approach, the frequency of core damage would be calculated from the frequency of initiating event I, λ(I) and the failure probabilities for A, B, C, and D [p(A), p(B), p(C), and p(D)]. Assuming $\lambda(I) = 0.1\ y^{-1}$ and $p(A|I) = 0.003$, $p(B|IA)$[a] $= 0.01$, $p(C|I) = 0.05$, and $p(D|IC) = 0.1$, the frequency of core damage is determined by calculating the frequency of each of the three core damage sequences and adding the frequencies:

$$0.1\ yr^{-1} \times (1 - 0.003) \times 0.05 \times 0.1 \text{ (sequence 3)} +$$

$$0.1\ yr^{-1} \times 0.003 \times (1 - 0.01) \times 0.05 \times 0.1 \text{ (sequence 6)} +$$

$$0.1\ yr^{-1} \times 0.003 \times 0.01 \text{ (sequence 7)}$$

$$= 4.99 \times 10^{-4}\ yr^{-1} \text{ (sequence 3)} + 1.49 \times 10^{-6}\ yr^{-1} \text{ (sequence 6)} + 3.00 \times 10^{-6}\ yr^{-1} \text{ (sequence 7)}$$

$$= 5.03 \times 10^{-4}\ yr^{-1}.$$

In a nominal PRA, sequence 3 would be the dominant core damage sequence.

As described earlier, the ASP Program calculates a conditional probability of core damage given an initiating event or component failures. This probability is different than the frequency calculated previously and cannot be directly compared with it.

[a]The notation P(B|IA) means the probability that B fails, given I occurred and A failed.

Table A.1. Rules for Precursor Calculation

Event sequences requiring calculation. If an initiating event occurs as part of a precursor (i.e., the precursor consists of an initiating event plus possible additional failures), then use the accident sequence model associated with the initiator; otherwise, use all accident sequence models impacted by the observed condition.
Initiating event probability. If an initiating event occurs as part of the precursor, then the initiating event probability used in the calculation is 1.0. If an initiating event does not occur as part of the precursor, then the probability is developed assuming a constant hazard rate. Event durations (the period of time during which the failure existed) are based on information included in the event report, if provided. If the event is discovered during testing, then one-half of the test period (15 d for a 30-d test interval) is typically assumed, unless a specific failure duration is identified.
Component failure probability estimation. For components that are observed failed during the precursor, the associated basic event is set to "true." Associated common-cause basic events are revised to reflect the type of failure that occurred. For components that are observed to operate successfully or that are not challenged during the event, a failure probability equal to the nominal component failure probability is utilized.
Nonrecovery probability. If an initiating event or a total system failure occurred as a part of the precursor, then the basic event representing the probability of not recovering from the failure is revised to reflect the potential for recovery of the specific failures observed during the event. For condition assessments, the probability of nonrecovery is estimated under the assumption that an initiating event has occurred.
Failures in support systems. If the support system is not included in the ASP models, the impact of the failure is addressed by setting impacted components to failed. The modeling of a support system failure recognizes that as long as the failure remains unrecovered, all impacted components are unavailable; but if the support system failure is recovered, all impacted components are also recovered. Such failures can be modeled through multiple calculations that address the impact of failure and success of the failed support system components. Calculated core damage probabilities for associated cut sets for each case are normalized based on the likelihood of not recovering the support system failure. (Support systems, except for emergency power, are not included in the current ASP models.)

A.5.1 Example 1: Initiating Event Assessment

Assume that a precursor involving initiating event I occurs. In response to I, systems A and C start and operate correctly, and systems B and D are not demanded. In a precursor initiating event assessment, the probability of I is set to 1.0. Although systems A and C were successful, nominal failure probabilities are assumed. Because systems B and D were not demanded, a nominal failure probability is assumed for them as well. The conditional probability of core damage associated with precursor I is calculated by summing the conditional probabilities for the three sequences:

$$1.0 \times (1 - 0.003) \times 0.05 \times 0.1 \text{ (sequence 3)} +$$

$$1.0 \times 0.003 \times (1 - 0.01) \times 0.05 \times 0.1 \text{ (sequence 6)} +$$

$$1.0 \times 0.003 \times 0.01 \text{ (sequence 7)}$$

$$= 5.03 \times 10^{-3}.$$

If instead B was determined to have been failed at the time of initiating event I, its probability would have been set to 1.0. The conditional core damage probability for precursor IB would be calculated as

$$1.0 \times (1 - 0.003) \times 0.05 \times 0.1 \text{ (sequence 3)} + 1.0 \times 0.003 \times 1.0 \text{ (sequence 7)} = 7.99 \times 10^{-3}.$$

Because B is failed, sequence 6 cannot occur.

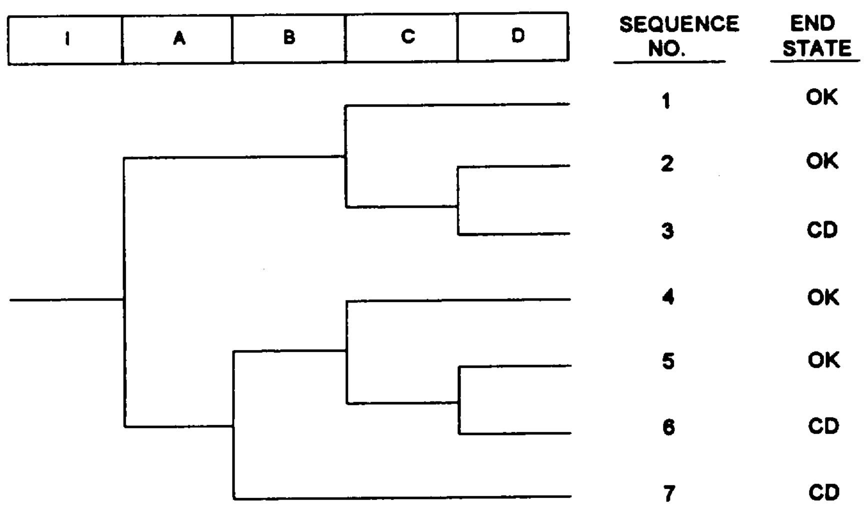

Fig. A.1 Hypothetical core damage model.

A.5.2 Example 2: Condition Assessment

Assume that during a monthly test system B is found to be failed and that the failure could have occurred at any time during the month. The best estimate for the duration of the failure is one-half of the test period or 360 h. To estimate the probability of initiating event I during the 360-h period, the yearly frequency of I must be converted to an hourly rate. If I can only occur at power, and if the plant is at power for 70% of a year, then the frequency for I is estimated to be 0.1 $yr^{-1}/(8760\ h/yr^{-1} \times 0.7) = 1.63 \times 10^{-5}\ h^{-1}$.

The expected number of core damage sequences in the 360-h period is

$$1.63 \times 10^{-5}\ h^{-1} \times 360\ h \times (1 - 0.003) \times 0.05 \times 0.1 \text{ (sequence 3)} +$$

$$1.63 \times 10^{-5}\ h^{-1} \times 360\ h \times 0.003 \times 1.0 \text{ (sequence 7)}$$

$$= 4.69 \times 10^{-5},$$

and the probability of at least one core damage sequence is[a]

$$1 - e^{-4.69 \times 10^{-5}} = 4.69 \times 10^{-5}.$$

As before, because B is failed, sequence 6 cannot occur. The conditional probability is the probability of core damage in the 360-h period, given the failure of B. Note that the dominant core damage sequence is sequence 3, with a conditional probability of 2.93×10^{-5}. This sequence is unrelated to the failure of B. The potential failure of systems C and D over the 360-h period still drives the core damage risk.

To understand the significance of the failure of system B, another calculation—an importance measure—is required. The importance measure that is used is equivalent to risk achievement worth on an interval scale (see Ref. 5). In this calculation, the increase in core damage probability over the 360-h period because of the failure of B is estimated:

$$p(cd \mid B) - p(cd) = \Delta CDP.$$

In this example the value is

$$4.69 \times 10^{-5} - 2.95 \times 10^{-5} = 1.74 \times 10^{-5},$$

where the second term on the left side of the equation is calculated using the previously developed probability of I in the 360-h period and nominal failure probabilities for A, B, C, and D.

The importance measure for unavailabilities (condition assessments) like this event was previously referred to as the conditional core damage probability (CCDP) in 1993 and earlier annual precursor reports. For most conditions identified as precursors in the ASP Program, its value and the CCDP are numerically close, and the

[a]Note that this calculation assumes that failures are only detected when core damage occurs. This calculational approach, adopted in 1995, differs from previous years when it was assumed that a failed component would be detected when the first initiating event occurred. The current approach may overestimate the core damage probability for a long-duration condition that would be detected at the time of the initiating event, but has little impact on most analyses. (The earlier approach could underestimate the event significance for failures that would remain undetected following a nominal initiating event.)

CCDP can be used as a significance measure for the precursor. However, for some events—typically those in which the components that are failed are not the primary mitigating plant features—the CCDP can be significantly higher than the importance. In such cases, it is important to note that the potential failure of other components, unrelated to the precursor, are still dominating the plant risk (i.e., the impact of the precursor on plant risk is not substantial). Condition assessments documented in this report include both an estimate of the CCDP and the importance of the event.

A.6 References

1. *PRA Procedures Guide*, USNRC Report, NUREG/CR-2300, January 1983, Section 6.3.2.

2. *Systems Analysis Programs for Hands-on Integrated Reliability Evaluations (SAPHIRE) Version 5.0*, USNRC Report, NUREG/CR-6116, Vols. 1–10.

3. *Procedures for Treating Common-Cause Failures in Safety and Reliability Studies*, USNRC Report, NUREG/CR-4780, January 1989, Appendix C.

4. E. M. Dougherty and J. R. Fragola, *Human Reliability Analysis*, John Wiley and Sons, New York, 1988.

5. W. E. Vesely, T. C. Davis, R. S. Denning, and N. Saltos, *Measures of Risk Importance and Their Applications*, USNRC Report, NUREG/CR-3385, July 1983.

Appendix B:

At-Power Precursors for 1998

B.1 At-Power Precursors

B.1.1 Accident Sequence Precursor Program Event Analyses for 1998

This appendix documents 1998 operational events selected as precursors that are analyzed with the plant in an at-power condition.

Licensee event reports (LERs) and other event documentation describing operational events at commercial nuclear power plants were reviewed for potential precursors if

1. the LER was identified as requiring review based on a computerized search of the Sequence Coding and Search System data base maintained at the Nuclear Operations Analysis Center (NOAC), or

2. the LER or other event documentation was identified as requiring review by the NRC Office for Analysis and Evaluation of Operational Data.

Details of the precursor review, analysis, and documentation process are provided in Appendix A of this report.

B.1.2 Precursors Identified

Ten precursors were identified among the 1998 events reviewed at the NOAC. Events were identified as precursors if they met one of the following precursor selection criteria and the conditional core damage probability (CCDP) estimated for the event was at least 10^{-6}:

1. the event involved the total failure of a system required to mitigate effects of a core damage initiator,

2. the event involved the degradation of two or more systems required to mitigate effects of a core damage initiator,

3. the event involved a core damage initiator such as a loss of offsite power (LOOP) or small-break loss-of-coolant accident (SLOCA), or

4. the event involved a reactor trip or loss-of-feedwater with a degraded safety system.

The precursors identified are listed in Table B.1.

Table B.1 List of 1998 Precursors

Event Number	Plant	Event descriptions	Page
LER 155/98-001	Big Rock Point	Standby liquid control system unavailable for 13 years	B.2-1
LER 269/98-004, -005	Oconee 1, 2, and 3	Calibration and calculational errors compromise emergency core cooling system transfer to emergency sump	B.3-1
LER 315/98-005	Cook 1	A postulated crack in a unit 2 main steam line may degrade the ability of the adjacent CCW pumps to perform their function	B.4-1
LER 346/98-006	Davis-Besse 1	A tornado touchdown causes a complete (weather-related) LOOP	B.5-1
LER 346/98-011	Davis-Besse 1	Manual reactor trip while recovering from a component cooling system leak and de-energizing of safety-related bus D1 and nonsafety bus D2	B.6-1
LER 361/98-003	San Onofre 2	Inoperable sump recirculation valve	B.7-1
LER 454/98-018	Byron 1	Long-term unavailability (18 d) of an EDG	B.8-1

B.1.3 Event Documentation

Analysis documentation and precursor calculation information for each precursor are attached. The precursors are in docket/LER number order.

For each precursor, an event analysis sheet is included. This sheet provides a description of the operational event, event-related plant design information, the assumptions and approach used to model the event, analysis results, and references.

A figure is included that highlights the dominant core damage sequence associated with the event. Conditional core damage calculation information is also provided. This includes the following tables:

- probabilities for selected basic events;
- sequence logic, sequence probabilities, and importances and system names for higher probability sequences; and
- higher probability cut sets for higher probability sequences.

B.2 LER No. 155/98-001

Event Description: Long-term unavailability of the liquid poison control system

Date of Event: July 14, 1998

Plant: Big Rock Point Nuclear Plant

B.2.1 Event Summary

On March 27, 1998, during decommissioning activities at the Big Rock Point Nuclear Plant (Big Rock Point), personnel made an unsuccessful attempt to discharge the contents of the plant's liquid poison control system (LPS) tank to a group of 0.25-m^3 (55-gal) drums. An air source was connected to the tank for expelling the liquid poison (sodium pentaborate) out of the tank via the discharge pipe. However, rather than the expected liquid poison, air flowed out of the LPS tank. Subsequently, a boroscope was used to inspect the internals of the LPS tank. This inspection revealed that the discharge pipe had totally corroded through; the corroded hole area at the interface was large enough to prevent pressurization of the LPS solution in the tank for subsequent discharge to the primary system. As a result, the LPS was incapable of fulfilling its design safety function—namely, to shut down the reactor in the event of an anticipated transient without scram (ATWS) event. Metallurgical analysis concluded that the pipe protective coating failed due to blistering, allowing the liquid-vapor environment/sodium pentaborate access to the carbon steel discharge pipe. The licensee postulated that failure of the discharge pipe occurred sometime between 1979 and 1984 (Ref. 1). On August 29, 1997, Big Rock Point shut down permanently for decommissioning; the LPS is not required to be operable for decommissioning. The estimated conditional core damage probability (CCDP) associated with this condition at Big Rock Point is 6.5×10^{-5}. This is an increase of 1.1×10^{-5} over the nominal core damage probability (CDP) in a 1-year period for Big Rock Point of 5.4×10^{-5}.

B.2.2 Event Description

On March 27, 1998, an unsuccessful attempt was made to discharge the contents of the LPS tank to a group of 0.25-m^3 (55-gal) drums. An air source was connected to the tank to expel the liquid poison out the discharge pipe. Instead of the expected liquid poison discharge from the LPS tank, air flowed out. A subsequent boroscope inspection of LPS tank internals revealed that the discharge pipe had totally corroded through; the corroded hole area at the interface was large enough to prevent pressurization of the LPS solution in the tank for subsequent discharge to the primary system. Personnel subsequently removed the tank manway and confirmed that the discharge line was severed into two pieces, compromising the function of the system. The LPS is not required to be operable during decommissioning. However, the licensee postulated that the discharge pipe failure occurred between 1979 and 1984. Thus, the plant had operated at power for up to 15 years with the LPS unavailable.

Both ends of the severed discharge pipe were shipped to the Consumer's Energy laboratory for analysis. The lab stated that the phenolic coating was completely stripped from the pipe, except for the last 46 cm (18 in.) of pipe. It was apparent that the break in the pipe was caused by corrosion. Visual inspection of the tank's inside walls revealed that the coating had failed or peeled off in many locations below the "liquid" line and was entirely gone from surfaces located above the liquid line. In another observation, red-oxide-colored rust was found on the surfaces that were above the liquid line, but generally not below the liquid line.

The purpose of the phenolic coating was to protect the tank and connecting piping surfaces from the sodium pentaborate, which would attain a slightly acidic solution. There were no surveillance or test requirements associated with the tank internals (i.e., inspection) or verifying (i.e., testing) that flow could exit the tank, although General Electric [the nuclear steam supply system (NSSS) vendor] stated that a means should be provided for periodically checking tank integrity. The licensee interviewed several people who have been employed at Big Rock Point for a long time, and none could recall that the manway flange on the LPS tank had ever been removed for either maintenance or inspection.

The licensee's evaluation of this failure concluded that a phenolic coating should not be expected to last 40 years. According to a materials expert (the licensee's contractor), a baked phenolic coating was one of the best choices for this application in the early 1960s. However, the maximum expected service life would be only about 10 years. Additionally, the air space above the water line was a highly corrosive environment. This air space was enclosed and contained water vapor from the liquid. There was also an ample supply of oxygen for the air space, which was supplied during every refueling outage when the licensee's personnel performed procedure TR-26, "Poison System Crystallization Inspection."

Big Rock Point's Technical Specifications allowed up to a 30% sodium pentaborate solution in the LPS tank. The specifications for the LPS tank itself specified a 20% solution of sodium pentaborate. However, the licensee concluded that the difference in concentration would not make much of a difference in the corrosion rates.

The licensee's investigation of the piping failure found that the root cause of the discharge pipe coating failure was blistering degradation within the first 3–5 years of LPS operation because of inadequate curing of the phenolic coating. Thorough curing of phenolic coatings is essential for acceptable coating performance when used in immersion service. Once the coating had failed, and the solution/environment had access to the pipe surface, direct preferential corrosion attack of the carbon steel discharge pipe occurred at the sodium pentaborate liquid/vapor interface because a differential aeration (oxygen) concentration cell existed at the liquid/vapor interface. Thus, the discharge pipe was exposed to an aqueous/oxygen environment at elevated temperatures. Corrosion attack will occur on carbon steel materials exposed to these conditions, and the corrosion reactions were accelerated by the elevated service temperatures [65.6–71.1°C (150–160°F)]. The corrosion rate of carbon steel in a closed system water environment containing dissolved oxygen at 65.6–71.1°C (150–160°F) is approximately 0.038–0.041 cm/year (0.015–0.016 in./ year).

The discharge pipe was specified as Schedule 40 with a 0.549-cm (0.216-in.) minimum wall thickness (MWT). Typically, pipe wall thickness can vary from specified MWT up to 10% greater than specified MWT. Thus, the discharge pipe wall thickness was probably between 0.549–0.605 cm (0.216–0.238 in.). With pipe corrosion rates of 0.038–0.041 cm/year (0.015–0.016 in./year), throughwall corrosion should have occurred at the interface in ~14–16 years, once the pipe was exposed to the service environment. At some short time after initial throughwall penetration, the corroded hole area at the interface was large enough to prevent pressurization of the LPS solution in the tank for subsequent discharge to the primary system. At this point, the liquid poison system became inoperable. The licensee postulated that failure occurred between 1979 and 1984 (the plant was put into service in 1962).

B.2.3 Additional Event-Related Information

The standby liquid control system (designated the LPS at Big Rock Point) was provided to inject a sodium pentaborate solution into the reactor vessel if the reactor could not be shut down with control blades. The LPS used nitrogen pressurized to 13.8 MPa (2000 psig) to rapidly inject its contents into the vessel; no pumps were necessary. The LPS consisted of a spherical 5.72-cm (2.25-in.) thick pressure vessel designed to American Society of Mechanical Engineers Boiler Pressure Vessel Code Sect. VIII, 1959 edition. The tank was approximately 183 cm (72 in.) in diameter, with a nominal capacity of 3.86 m^3 (850 gal). The internal surfaces of the tank, manhole neck, inside and outside of the outlet and dip tubes, along with all flange faces, were coated with a baked phenolic protective lining.

Upon initiation of the poison valves admitting 13.8 MPa (2000 psig) of nitrogen pressure to the poison tank, poison would be forced into the reactor within a few seconds. This ensured a positive displacement of the solution when the reactor recirculation system was static, such as during refueling, when there was no initial driving head to establish a siphon through the discharge dip tube in the poison tank.

B.2.4 Modeling Assumptions

While the current version of the plant-specific models [the standardized plant analysis risk (SPAR) models] used in the detailed analyses performed by the Accident Sequence Precursor (ASP) Program, was being developed, the Big Rock Point licensee announced plans to shut down the plant permanently for decommissioning. The ASP Program subsequently stopped the development of the most recent version of the model for Big Rock Point and concentrated on models for plants that were still operating. Because no current ASP Program model exists for Big Rock Point, this analysis used the models and the analysis results documented in the licensee's individual plant examination (IPE) for Big Rock Point (Ref. 2).

According to Ref. 2, two sequences from the turbine trip ATWS event tree (sequences 12 and 13 in Fig. 1) contribute ~90% of the overall ATWS contribution to the core damage frequency (CDF). These sequences include success of the main condenser as a heat sink and LPS failure. LPS failure is dominated by the operator failing to provide injection within 2 min (this operator action included tripping the reactor recirculating water pump and LPS initiation). If LPS failed to inject due to mechanical means, the operator action would remain applicable for the recirculating water pump trip action. With the pumps tripped and steam bypassed to the main condenser, for some sequences, the plant could survive the turbine trip without the reactor scram. In those cases, sufficient time would be available to pursue other means of inserting the control rods or providing alternate poison injection through the use of borax and boric acid batched through the condensate / makeup system and injected through the feedwater system.

As described in Ref. 2, the turbine trip ATWS scenario would have been expected to proceed as follows: while the reactor was operating at 100% power with the turbine-generator on-line, a trip would occur (turbine stop valve closure and the generator output breaker opening). As the stop valve closed, pressure would rise within the main steamline and ultimately within the primary system. The pressure increase in the primary system would cause neutron flux levels to increase (as a result of a reduction in void volume), and initiate a reactor scram. The turbine bypass valve would also open to control pressure by sending steam directly to the main condenser (the bypass system and condenser were designed for 100% load rejection capability). The operators would respond to the turbine trip by verifying that a reactor scram occurred or by initiating manual scram actions for an automatic scram failure. If the automatic or manual scram actions fail, the operators would then trip the reactor recirculating water pumps and initiate LPS injection. Tripping the recirculating water pumps would reduce reactor power output to 60% (or 50%, if both pumps were tripped) of its previous value. If the LPS failed with the reactor depressurization system (RDS) inhibited, the main steam isolation valves (MSIVs) would close ~4 min into the event, and the safety/relief valves (SRVs) would actuate to relieve steam into the containment. Operation of the emergency condenser and restoration of feedwater would extend the time until core damage occurred, provided that RDS was inhibited (Ref. 2, p.7.1.5-17). On the other hand, if LPS failed and RDS were not inhibited, blowdown of the reactor to allow injection of core spray [0.52 MPa (75 psig)] would occur within seconds following the actuation of the RDS. Reflooding of the reactor with cold core spray water was assumed to return the reactor to power, although with some degree of core damage (Ref. 2, p. 7.1.5-23).

Figure B.2.1 provides the ATWS–Turbine Trip event tree from the Big Rock Point IPE. Table B.2.1 identifies the ATWS sequences from Ref. 2 that have frequencies greater than the IPE truncation value of 1.0×10^{-9}/year; Table B.2.2 provides the system names. Table B.2.3 provides the frequency for each sequence including the event initiator (e.g., turbine trip, complete loss of feedwater), and the reactor protection system failure that would result in an ATWS event. In Ref. 2, the licensee assumed that electrically-caused trip failures could be recovered by operator action to manually actuate the trip breakers. This assumption reduced the probability of failure-to-trip by a factor of 3.0 compared to the value typically used in Probabilistic Risk Assessments.

In Ref. 2, the licensee's analysis assumed that operator actions associated with failing to actuate the LPS and failing to inhibit the RDS were strongly coupled [i.e., p(operator fails to inhibit RDS | operator fails to initiate LPS) = 1.0], because both actions are cued by the same signals and at the same time. For the condition of interest (LPS unavailable), the operator action to inhibit RDS should still be successful [p(operator fails to inhibit RDS) = p(operator fails to initiate LPS)], although the LPS is in a failed state because of the nature of the LPS failure. However, in terms of a core damage end state, this makes no difference because, as discussed previously, successfully inhibiting RDS following LPS failure merely delays the onset of core damage.

For each sequence listed in Table B.2.3, Ref. 2 reports the time available for the operators to actuate the LPS. Based on this time, it was possible to identify the corresponding human error probability used in the sequence. Assuming that the probability of LPS failure is dominated by operator action (this assumption seems reasonable—at least for the fast response sequences with very high human error probabilities that dominate the results), revised sequence frequencies, given that the LPS was failed, were calculated.

The event trees and fault trees developed by the licensee and the accompanying assumptions used to analyze ATWS initiators and the resulting accident sequences documented in detail in Sect. 7.1.5 of Ref. 2 were reviewed and considered appropriate for use in this analysis of the long-term unavailability of the LPS. The ATWS sequences with frequencies above the IPE truncation value of 1.0×10^{-9} per year (identified in Section 7.1.5 of Ref. 2) were then manipulated to estimate the increase in CDF for long-term LPS unavailability. Using this result, the increase in CDP associated with LPS unavailability for a 1-year period (the maximum unavailability duration considered in the ASP Program) was then estimated. From the nominal ATWS sequence frequencies, the CDF contribution from ATWS was then used with the estimated overall CDF from the Big Rock Point IPE to estimate the CCDP.

B.2.5 Analysis Results

Table B.2.3 identifies the IPE CDF for ATWS sequences, 3.7×10^{-6}/year (Column 5), as well as the ATWS CDF, given the unavailability of LPS, estimated using the IPE, 1.5×10^{-5}/year (Column 7). Since LPS unavailability only impacts ATWS sequences, the difference between the IPE CDF for ATWS sequences and the ATWS CDF, given the loss of LPS is

$$\Delta CDF_{ATWS} = CDF_{ATWS} - CDF_{ATWS} \mid LPS_{unavailable}$$

$$= 1.5 \times 10^{-5}/year - 3.7 \times 10^{-6}/year = 1.1 \times 10^{-5}/year$$

This value can be used in conjunction with the overall IPE CDF (5.4×10^{-5}/year) to estimate the LPS unavailability. The overall conditional CDF (conditional frequency of subsequent core damage given the failures observed during an operational event), given the unavailability of LPS, is the significance of

$$CCDF_{TOTAL} = CDF_{TOTAL} + \Delta CDF_{ATWS} = 5.4 \times 10^{-5}/year + 1.1 \times 10^{-5}/year = 6.5 \times 10^{-5}/year$$

For a 1-year period, the associated CCDP is

$$CCDP = 1 - e^{CCDF_{TOTAL} \times 1\ year}$$

$$= 1 - e^{6.5 \times 10^{-5}/year \times 1\ year} = 6.5 \times 10^{-5}$$

The nominal CDP for the same period is

$$CDP = 1 - e^{CDF_{TOTAL} \times 1\ year}$$

$$= 1 - e^{5.4 \times 10^{-5}/year \times 1\ year} = 5.4 \times 10^{-5}$$

Using these two values, the increase in CDP (importance) is

$$\Delta CDP = CCDP - CDP = 6.5 \times 10^{-5} - 5.4 \times 10^{-5} = 1.1 \times 10^{-5}$$

The two dominant sequences, 12 and 13 (see Fig. B.2.1), together contribute about 80% to the increase in CDP (event importance) for this condition. Recall that according to Ref. 2, sequences 12 and 13 contribute ~90% of the overall ATWS contribution to the CDF. The contribution of these two sequences decreases because the human errors, which are more likely in sequences 12 and 13, are factored out.

Sequences 12 and 13 both consist of

- A turbine trip
- Postulated failure of automatic and manual reactor scram
- Successful opening of turbine bypass valve to send steam directly to main condenser
- Failure of recirculating water pump trip (no credit taken for manual trip in Ref. 2)
- Successful opening of the SRVs
- Failure of LPS to inject liquid poison.

Up to this point, the two sequences are identical. The last top event in the event tree, Secure Core Cooling, addresses maintaining the integrity of the containment to prevent releases of radioactivity (Ref. 2). During the response to an ATWS-related sequence, if the containment pressure should rise above 0.069 MPa (10 psig), the operator is instructed by the emergency operating procedures to terminate injection to the reactor vessel. If LPS fails, terminating makeup to the reactor coolant inventory will uncover the core, voids will induce subcriticality, and the amount of steam entering the containment will be limited, thereby preventing overpressurization. There are two possible scenarios for Sequence 12. If, following LPS failure, the operator successfully terminates coolant injection and inhibits RDS, core damage will occur with the reactor at high pressure. If the operator fails to inhibit RDS, then RDS actuation and core spray operation are assumed to occur. If the operator should subsequently terminate core spray, core damage will occur to an intact containment with the reactor at low pressure. If the operator takes no action either to inhibit RDS or to terminate core spray (Sequence 13), containment pressurization will continue with the amount of steam entering containment equivalent to the rate at which core spray is being added to the reactor vessel. As containment pressure and reactor pressure rise, coolant flow to the reactor (through core spray) will slow. If containment pressure should rise to 0.59 MPa (85 psig), the reactor pressure will exceed the shutoff head of the fire pumps, and the coolant flow to the reactor will stop altogether. In this case, core damage would occur with the reactor at low pressure, but with the containment pressurized to near its capacity.

B.2.6 References

1. LER No. 155/98-001, "Liquid Poison Tank Discharge Pipe Found Severed during Facility Decommissioning," August 6, 1998.

2. *Big Rock Point Probabilistic Risk Assessment*, Vols. 1, 2, and 3, submitted via letter from P. M. Donnelly, Consumers Power, to Document Control Desk, Nuclear Regulatory Commission, dated May 5, 1994.

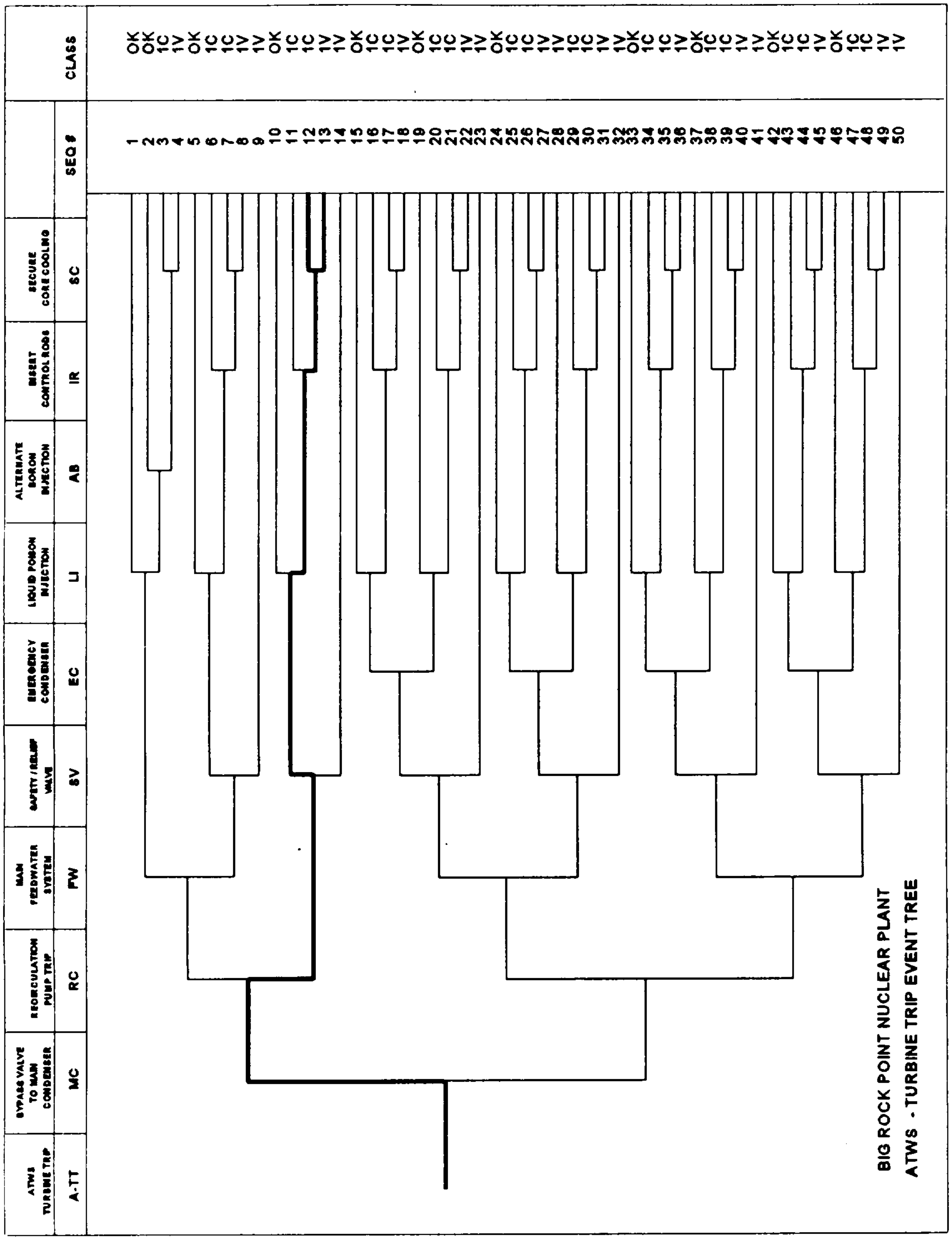

Fig. B.2.1 Dominant core damage sequences for LER No. 155/98-001 (*Source*: *Big Rock Point Probabilistic Risk Assessment*, Vols. 1, 2, and 3, submitted via letter from P. M. Donnelly, Consumers Power, to Document Control Desk, Nuclear Regulatory Commission, dated May 5, 1994, Fig. 7.1.5.3-2). [Under CLASS, 1C denotes sequences involving loss of scram function and loss of coolant inventory, 1V denotes sequences involving loss of scram function and loss of all reactivity control; and OK denotes transient terminated].

Table B.2.1. Sequence Logic for Dominant Sequences for LER No. 454/98-018

Sequence number	Class[a]	Logic
3	1C	A-TT, /MC, /RC, /RW, LI, AB, /SC
4	1D	A-TT, /MC, /RC, /RW, LI, AB, SC
8	1V	A-TT, /MC, /RC, FW, /SV, LI, IR, SC
9	1V	A-TT, /MC, /RC, FW, SV
12	1C	A-TT, /MC, RC, /SV, LI, IR, /SC
13	1V	A-TT, /MC, RC, /SV, LI, IR, SC
17	1C	A-TT, MC, /RC, /FW, /SV, /EC, /LI, IR, /SC
18	1V	A-TT, MC, /RC, /FW, /SV, /EC, /LI, IR, SC
26	1C	A-TT, MC, /RC, FW, /SV, /EC, LI, IR, /SC
27	1V	A-TT, MC, /RC, FW, /SV, /EC, LI, IR, SC

[a]1C denotes sequences involving loss of scram function and loss of coolant inventory, 1V denotes sequences involving loss of scram function and loss of all reactivity control, and OK denotes transient terminated.

Table B.2.2. System Names for LER No. 454/98-018

System name	Logic
AB	Alternate boron injection through the feedwater system
A-TT	ATWS – turbine trip
EC	Emergency condenser
FW	Main feedwater
IR	Operators manually insert control rods
LI	Liquid poison injection (specifically, the LPS system)
MC	Bypass valve to main condenser
RC	Recirculation pump trip
SC	Secure core cooling
SV	Safety / relief valve

Table B.2.3. Requantification of Dominant ATWS Sequences Considering LPS Failure

Initiator	Sequence	Class[a]	Time available for injection (min)	Sequence frequency from IPE (per year)	Human error probability (HEP) (from IPE)	Sequence frequency / HEP = conditional frequency (per year)
Turbine trip	12	1C	2	1.7×10^{-6}	3.0×10^{-1}	5.7×10^{-6}
	13	1V	2	1.7×10^{-6}	3.0×10^{-1}	5.7×10^{-6}
	17	1C	12	2.5×10^{-9}	1.0×10^{-2}	2.5×10^{-7}
	18	1V	12	2.5×10^{-9}	1.0×10^{-2}	2.5×10^{-7}
Spurious bypass valve opening	12	1C	2	7.4×10^{-8}	3.0×10^{-1}	2.5×10^{-7}
	13	1V	2	7.4×10^{-8}	3.0×10^{-1}	2.5×10^{-7}
Complete loss of feedwater	8	1V	2	7.5×10^{-8}	3.0×10^{-1}	2.4×10^{-7}
	9	1V	2	7.5×10^{-8}	3.0×10^{-1}	2.4×10^{-7}
Spurious MSIV closure	No sequences with CDFs > 1.0×10^{-9}/year					
Loss of main condenser	3	1C	12	2.4×10^{-9}	1.0×10^{-2}	2.4×10^{-7}
	4	1V	12	2.4×10^{-9}	1.0×10^{-2}	2.4×10^{-7}
Loss of station power	3	1C	8	7.9×10^{-9}	2.5×10^{-2}	3.2×10^{-7}
	4	1V	8	7.9×10^{-9}	2.5×10^{-2}	3.2×10^{-7}
Loss of instrument air	26	1C	12	7.9×10^{-9}	2.1×10^{-2}	3.8×10^{-7}
	27	1V	12	7.9×10^{-9}	2.1×10^{-2}	3.8×10^{-7}
Total				**3.7×10^{-6}**		**1.5×10^{-5}**

[a] 1C denotes sequences involving loss of scram function and loss of coolant inventory, 1V denotes sequences involving loss of scram function and loss of all reactivity control, and OK denotes transient terminated.

B.3 LER No. 269/98-004, -005

Event Description: Calibration and calculational errors compromise emergency core cooling system transfer to emergency sump

Date of Event: February 12, 1998

Plant: Oconee 1, 2, and 3

B.3.1 Event Summary

At the Oconee Nuclear Plant, Units 1, 2, and 3 (Oconee 1, 2, and 3), incorrect calibration of the borated water storage tank (BWST) level instruments, failure to address potential errors in reactor building emergency sump (RBES) indicated level, and incorrect estimation of expected RBES level resulted in (1) the potential for emergency core cooling system (ECCS) pump loss of net positive suction pressure (NPSH) and vortexing, and (2) a situation where the emergency operating procedure (EOP) requirements for BWST-to-RBES transfer would never have been met. This would have required ad-hoc operator action to maintain post-loss-of-coolant accident (LOCA) core cooling. The estimated conditional core damage probability (CCDP) associated with these conditions is 2.0×10^{-5} at Oconee 1 and 2 and 1.9×10^{-5} at Oconee 3. This is an increase of 1.7×10^{-6} at Oconee 1 and 2 and 1.4×10^{-6} at Oconee 3 over the nominal core damage probability (CDP) in a 1-year period of 1.8×10^{-5}.

B.3.2 Event Description

On February 12, 1998, Oconee 1 was at 65% power and Oconee 2 and 3 were at 100% power. During an investigation of a Self-Initiated Technical Audit (SITA) issue, personnel at Duke Power determined that the BWST level instruments were miscalibrated by as much as 46 cm (18 in.) lower than assumed in the calculations supporting EOP actions. Because of the calibration error, the indicated water level in the BWST was higher than the actual water level. Consequently, during the drain-down of the BWST following a postulated LOCA, unacceptable ECCS and reactor building spray pump NPSH and vortex formation may occur before the operators, while complying with the EOPs, transfer pump suction from the BWST to the reactor building (RB) sump.[1]

The BWST level calibration errors occurred when three new level transmitters were installed in 1989, replacing two older pneumatic level instrument trains. The field installation drawings specified that the new transmitters be mounted at elevation "799-1 or below." As a result, the new calibration test tees for each instrument were typically located ~0.3 m (1 ft) below the elevation of the impulse line tap into the system, but in the worst case the elevation difference was ~0.46 m (1.5 ft), as shown in Fig. B.3.1 and Table B.3.1. (Level transmitters LT 2A and LT 6 are the primary indicators of the water level in the BWST following a LOCA.) A review of the drawings for the original pneumatic instruments indicated an elevation difference of approximately 10 cm (4 in.). Although the calibration procedure was revised after the new transmitters were installed, the revision did not address the elevation differences. (Current Oconee practice in other instrument calibration procedures is to include a "zero offset" on the calibration data sheet to account for the difference between the instrument test tee and impulse line tap elevations.)

A second potential source of calibration error, the relative height of the calibration test instrument compared to the calibration test tee, was also missing from the calibration procedure. Personnel determined that this error would substantially impact instrument calibration because the calibration test instrument elevation is adjusted to match the elevation of the test tee.

In 1986, a series of instrument error calculations, which addressed the BWST level instruments, were performed to determine the appropriate procedural set points for BWST-to-RBES transfer to satisfy ECCS pump NPSH requirements and to avoid vortexing in the pump suction lines. These calculations assumed that the zero reference elevation for the BWST level instruments was the elevation of the impulse line tap. In January 1988, these calculations were designated OSC-2820, *Emergency Procedure Guidelines Set Points*, to document the sources and derivation of numerical values used as EOP set points.

Although these calculations were updated on several occasions after the BWST level instruments were replaced in 1989, the assumed zero reference point was not changed. Therefore, because personnel calibrated the BWST level instruments to the test tee elevation rather than to the impulse line tap elevation, the error between the water level in the BWST assumed in the EOP calculations and the indicated water level differed by 0.30 to 0.46 m (1.0 to 1.5 ft) in the nonconservative direction. This error is a significant fraction of the 1.8-m and 0.6 m (6-ft and 2-ft) BWST level set point action statements included in the EOPs. All BWST level transmitters were recalibrated to address the test tee elevation errors by 0431 on February 13, 1998, the day after the problem was discovered.

One week after the BWST level instrumentation miscalibration was found, personnel identified another problem related to the BWST-to-RBES transfer. The Oconee EOPs at the time of this event required the operators to begin the BWST-to-RBES transfer when the water level in the BWST was less than 1.8 m (6 ft) and the water level in the RBES was greater than 1.2 m (4 ft) (Ref. 2). The failure to consider instrument errors when the EOP minimum RBES level was specified, plus the incorrect calculation of the expected water level in the reactor building when the water level in the BWST dropped to 1.8 m (6 ft), resulted in the potential for the indicated water level in the RBES to never reach the 4-ft level required for transfer.

The original 1973 emergency procedure for transferring ECCS pump suction from the BWST to the RBES specified that the transfer should occur upon receipt of the low-low BWST level alarm, then set at 0.9 m (3 ft). No RBES level requirement was included in the original procedure.

In 1985, the ECCS pump suction transfer procedure was revised to require the water level in the BWST to be less than 1.8 m (6 ft) and the water level in the RBES to be more than 0.6 m (2 ft). The 2-ft RBES level was included as a precaution to ensure an adequate water level in the sump following pipe breaks that occurred outside containment. The RBES level instruments in place at the time had a range of 0 to 0.9 m (0 to 3 ft). Between December 1984 and December 1986, as part of post-Three Mile Island accident upgrades, two wide-range RB water level transmitters were installed at each of the three Oconee units. These instruments provide RBES level indication of 0 to 4.6 m (0 to 15 ft).

When OSC-2820, *Emergency Procedure Guidelines Set Points* was issued in January 1988 (as described previously), the results of calculations performed 1-month earlier that addressed the potential error in the new RBES water level instruments were used as inputs in determining the minimum pump NPSH requirements during the recirculation mode. An RBES set point of 1.1 m (3.5 ft) was established to ensure a minimum sump inventory for all accidents (the intent was to confirm that the inventory of water in the BWST had been transferred to the RB rather than to a location outside containment). The supporting analysis for the 1.1-m (3.5-ft) set point included an allowance of +22 cm (8.8 in.) for instrument error to account for the possibility that the level transmitters might read high, but did not recognize the possibility that the RBES level indication might read low and never reach the EOP set point.

In February 1988, the RBES level instrumentation calculation was revised to address current leakage. This calculation estimated the "worst-case" instrument error to be +22/-53 cm (+8.8/-21 in.)[a] At the time the calculation was revised, personnel estimated that the water level in the RB would be 163 cm (5.3 ft or 64 in.) when the water level in the BWST reached 1.8 m (6 ft). Assuming a worst-case instrument error (-53 cm or -21 in.), the water level in the RBES (109 cm or 43 in.) would be greater than the 107 cm (42 in. or 3.5 ft) water level required for the BWST-to-RBES transfer, but only marginally. In April 1988, the EOP was revised to incorporate the 1.1-m (3.5-ft) minimum RBES water level prior to transfer.

In July 1989, OSC-2820 was revised to require a minimum indicated RBES water level of 1.14 m (3.75 ft) to ensure that minimum NPSH requirements would be met. Because the calculation did not evaluate the potential impact of the RBES level instruments reading low, the fact that the 1.14-m (3.75-ft or 45-in) level [or 5 cm (2 in.) greater than the 109 cm (43 in.) lowest indicated level considering maximum instrument error) might not be reached was not recognized. The EOPs were not revised to reflect the changes to OSC-2820 at that time.

At the end of May 1994, the EOPs were revised to reflect a higher minimum water level in the RBES before the BWST-to-RBES transfer was made. For instrument readability reasons, the minimum indicated water level in the RBES was established at 1.2 m (4 ft), which met the 1.14-m (3.75-ft) level documented in OSC-2820. Again, this revision failed to consider the potential for the RBES level instruments reading low. Once the EOP change was made, the potential existed for the RBES level to indicate 13 cm (5 in.) below that which was procedurally specified when the operators were expected to begin actions required for transferring ECCS suction from the BWST to the RBES. This is based on an estimated water level in the RBES of 163 cm (64 in.) when the water level in the BWST was at 1.8 m (6 ft).

This problem was further impacted by another calculational error discovered in November 1997 (Ref. 3). The calculation of the inventory of water in the RBES (that had previously been used to estimate a water level depth of 163 cm (64 in.) in the RBES when the water level in BWST was at 1.8 m (6 ft)) was found to incorrectly account for the following trapped water volumes that would reduce the expected water level in the RBES following a LOCA:

- water trapped in the reactor vessel cavity and in the deep end of the fuel transfer canal,
- water needed to make up for reactor coolant system shrinkage during cooldown,

[a]The worst-case negative instrument error was revised in 1996 to -46.0 cm (-18.1 in.).

- water needed to refill the pressurizer,
- water needed to fill the reactor building spray piping inside containment, and
- water needed to account for the vapor content maintaining containment pressure.

Reference 3 noted that the reactor vessel cavity and the fuel transfer canal could trap a large quantity of water and significantly reduce the inventory in the RBES—thereby reducing the RBES water level. The reactor vessel cavity is the volume between the reactor vessel and the primary shield (Fig. B.3.2). Reactor coolant piping, core flood/decay heat removal piping, and in-core instrument tubing pass through the reactor vessel cavity. In addition, a drain line from the deep end of the fuel transfer canal empties into the cavity. The bottom of the reactor vessel cavity contains a 10-cm (4-in.) line that drains the cavity to the RB normal sump. However, the drain line was covered with a flange that contained a 1.9-cm (3/4-in.) pipe nipple that allowed very limited drainage (this flange was discovered to be missing at Unit 3).

The deep end of the fuel transfer canal could also trap a large quantity of water. Two lines are provided to drain the fuel transfer canal to the RB normal sump. Instead of perforated drain covers, the drain lines contained "basket strainers" that were believed to be much more likely to be blocked by debris, which would prevent the fuel transfer canal from draining. (An additional drain line, located 0.3 m (1 ft) above the bottom of the fuel transfer canal, provides an alternate drain path to the reactor vessel cavity; however, drainage through the reactor vessel cavity was essentially blocked by the 1.9-cm (3/4-in.) restriction discussed previously.) The basket strainers had been installed for as low as reasonably achievable (ALARA) purposes during an outage about 10 years ago and had been allowed to remain during operation without a proper station modification evaluation.

An evaluation considering the effects of water being trapped in the reactor vessel cavity and in the fuel transfer canal concluded that the expected water level in the RBES was 0.936 m (3.07 ft) instead of the 163 cm (64 in. or 5.3 ft) used in calculations for determining when the water level in the BWST reached 1.8 m (6 ft). This revised value would apply particularly to large- and medium-break LOCAs, when building spray would collect in the fuel transfer canal. Following the removal of the basket strainers and the flange on the reactor cavity drain in November 1997, the expected water level in the RBES was estimated to be ~1.4 m (4.5 ft).

In conclusion, three conditions that degraded the potential for BWST-to-RBES transfer were reported in Refs. 1 and 3. Incorrectly calibrated BWST level transmitters (1989–1998) could have resulted in ECCS pump loss of NPSH and vortexing when the operators performed the EOP steps required to place a unit on sump recirculation following a LOCA. Failure to consider potential RBES level instrument error when developing procedures for the BWST-to-RBES transfer, combined with the incorrect estimation of the expected water level in the RBES (1985–1998), could have resulted in a condition where EOP requirements for initiating BWST-to-RBES transfer would not have been met. This would have required ad-hoc operator action to maintain post-LOCA cooling.

B.3.3 Additional Event-Related Information

The Oconee ECCS (Fig. B.3.3) consists of a high-pressure injection (HPI) and low-pressure injection (LPI) system, as well as a core flood system. The HPI system includes three 24-stage vertical centrifugal pumps that develop 20.7-MPa (3000-psi) discharge pressure with a capacity of 0.032 m^3/s (500 gpm) each. The HPI system provides both normal makeup and reactor coolant pump seal injection, as well as makeup to the reactor coolant system (RCS) for small- and medium-break LOCAs. HPI pump A or B is normally in operation; HPI pump C is for emergency use only. The HPI pumps will typically operate for 1–2 min without an adequate suction source before they are damaged.

The Oconee LPI system also includes three pumps. These high-capacity, low head pumps provide RCS makeup for removing decay heat during normal shutdown operations or following a large-break LOCA. When the RCS is not depressurized below the LPI pump shutoff head, the LPI pumps also provide the suction source for the HPI pumps during the recirculation phase following a small- or medium-break LOCA. Two of the LPI pumps are automatically started for LOCA mitigation; the third pump is manually started if required. The LPI pumps are more tolerant of reduced NPSH than the HPI pumps and can operate for greater periods of time with reduced NPSH. [While no information is available concerning the expected Oconee LPI pump performance at reduced NPSH, Ref. 4 provided this information for another low-pressure, high-capacity pump—the containment spray pump at Maine Yankee. The manufacturer of that pump indicated that the pump could operate indefinitely at 95% of required NPSH and for 15 min at 75% of required NPSH. The pump manufacturer also stated that similar pumps are routinely operated for 1–3 min at 50% of required NPSH without sustaining damage.]

The Oconee BWSTs provide 1590 m^3 (350,000 gal) for injection when drawn down from the minimum Technical Specification (TS) level [14 m to 1.8 m (46 ft to 6 ft)]. Because the same BWST level channels are used to measure maximum and minimum water level, the BWST level calibration error did not impact the volume of water delivered to the RCS during the injection phase.

B.3.4 Modeling Assumptions

This analysis addressed the combined impact of (1) water trapped in the reactor vessel cavity and the fuel transfer canal, (2) the potential for RBES level instruments to indicate low due to instrument error, and (3) incorrectly calibrated BWST level transmitters that increase the probability that the operators would fail to transfer the ECCS pump suctions to the RBES once the inventory in the BWST is depleted. An event-specific model was developed to depict the potential combinations of instrument and operator errors that, following a LOCA or other condition requiring sump recirculation, could result in failure to transfer ECCS pump suction from the BWST to the RBES and result in the unavailability of long-term core cooling. This model, shown in Figs. B.3.4 and B.3.5, was used to estimate the importance of this event. Table B.3.2 provides the definitions and probabilities for the event tree branches. The Oconee Standardized Plant Analysis Risk (SPAR) models developed for use in the Accident Sequence Precursor (ASP) Program were used to determine the nominal CDP in a 1-year period. The event tree model includes the following branches:

Initiating Event (IE). The initiating events necessary to analyze this event consist of the set of sequences that require sump recirculation. Because of differences in timing, large-, medium- and small-break LOCAs and transients (including a loss of offsite power) that require feed-and-bleed cooling were addressed separately. Utilizing a 1-year time period (the longest interval analyzed in the ASP Program) and revising the initiating event frequencies to be consistent with historical values,[5] the probabilities of requiring sump recirculation for the different initiating events were estimated using the Oconee SPAR model. These probabilities are shown in Table B.3.3.

Sump Recirculation Required (RECIRC). The initiating events of interest represent the set of sequences and their associated probability in a 1-year period that sump recirculation would be required. The probabilities are weighted by 0.1 or 0.9 to reflect the probability that the water level in the BWST will be 14.0 to 14.8 m (46 or 48.5 ft), respectively.

RBES Level ≥ 1.2 m (4 ft) when BWST Level = 1.8 m (6 ft) (RBES-OK). Success for this branch implies that the water level in the RBES is at least 1.2 m (4 ft) when the water level in the BWST is drawn down to 1.8 m (6 ft). If the water level in the RB is at least 1.2 m (4 ft) when the water level in the BWST reaches 1.8 m (6 ft), this analysis assumes the operators will begin to transfer the ECCS pump suctions to the RBES as specified in the EOP.[2] If the water level in the RB is less than the 1.2 m (4 ft) required by the EOP, the potential exists for the operators to delay transfer until the ECCS pumps are damaged and can no longer be used for core cooling. The probability that the RBES level will not indicate 1.2 m (4 ft) when the water level in the BWST reaches 1.8 m (6 ft) (i.e., when the EOP requires the operators to transfer ECCS pump suction to the RBES) depends on the actual water level in the RB and the RB water level instrument error. These issues are discussed below.

a. *Impact of trapped water in reducing expected RBES level.* The primary contributors to the reduced RBES inventory reported in Refs. 1 and 3 were associated with the deep end of the fuel transfer canal and the reactor vessel cavity. At Units 1 and 2, the reactor vessel cavity drain line included a flange with a 1.9-cm (3/4-in.) pipe nipple that effectively prevented the reactor vessel cavity from draining to the RB sump (Fig. B.3.2). At Unit 3, the pipe flange was found to be missing. This would have allowed water that entered the Unit 3 reactor vessel cavity to drain into the RB sump.

   The deep end of the fuel transfer canal drained to the RB sump through basket strainers at each of the units. The potential existed for these strainers to become clogged, thereby preventing the fuel transfer canal from draining. However, when the strainers were inspected, they were found to be clean at each unit[a] and would have allowed the fuel transfer canal to drain to the sump. The water drained from the fuel transfer canal would increase the calculated RB sump level an additional 0.23 to 1.2 m (0.75 to 3.8 ft), for Units 1 and 2. The missing reactor vessel cavity drain flange at Unit 3 would have allowed that unit's reactor vessel cavity to drain as well, resulting in a calculated RB sump level of 1.4 m (4.5 ft); this is the same as the calculated water level after the basket strainer and reactor vessel drain flange issues were resolved. These sump levels assume the BWST was initially at the TS-required level of 14.0 m (46 ft) and was drained to 1.8 m (6 ft) at the time the ECCS pump suctions were transferred to the RBES. In actuality, the BWST is maintained at a level of 14.8 m (48.5 ft) about 90% of the time, which would increase the water level in the sump at the time operators transfer to the sump.[a]

b. *Potential RBES level instrument error.* The estimated error for the RBES level channels is +22/−46 cm (+8.8/−18.1 in.), including current leakage. Based on information provided by personnel at Duke Power following the January 28, 1999, telephone conversation with Nuclear Regulatory Commission (NRC) and ASP program staff, this error is assumed to represent the ±2σ values of an approximately normal distribution. Using this assumption and the expected water levels in the RB described above, the probability

[a]Personal communication, J. W. Minarick (SAIC) and R. L. Oakley (Duke Power), March 1, 1999.

that both RBES level channels will read less than 1.2 m (4 ft) can be estimated.[a] Using the +22-cm (+8.8-in.) and -46-cm (-18.-in.) values, the mean error (due to current leakage) is calculated to be -12 cm (-4.7 in.) and the standard deviation (σ) is calculated to be 17 cm (6.7 in.) For Oconee 1 and 2, with a calculated water level in the RB sump of 116 cm (45.6 in. or 3.8 ft), the probability that an RB level channel will not read 122 cm (48 in. or 4 ft) is estimated to be

$$\Phi[(48 \text{ in} - \text{mean level})/\sigma] = \Phi[(48 - (45.6 - 4.7)) / 6.7] = 0.86\,,$$

where $\Phi[\ ]$ is the cumulative normal probability distribution. The probability of not exceeding 1.2 m (4 ft) on either channel can be estimated using the independent failure probability (0.86) and the correlation in the errors in the two channels. Unfortunately, essentially no information exists concerning the expected correlation between the two channels. As a surrogate for this information, data developed in conjunction with an NRC reactor protection system reliability study[6] was used to estimate a β-factor for the common-cause failure of the two level channels.[b] The resulting estimate (β = 0.024) implies a very limited correlation between the two channels. Using this estimate for β, the probability that the RB water level indicators will not indicate that the level is at least 1.2 m (4 ft) on either channel is estimated to be 0.735. Because of the limited correlation between channels, this compares to a probability of 0.732 if the channels were independent.

The probability (to two significant figures) of not indicating 1.2 m (4 ft) on either RB level channel for initial BWST levels of 14.0 m and 14.8 m (46 ft and 48.5 ft) at a BWST drain-down to 1.8 m (6 ft) (the EOP-specified level to begin transferring ECCS pump suctions to the RBES) is shown in Table B.3.4.

Cold-Leg Break (CLBREAK). Success for this branch implies that the LOCA occurred in one of the cold legs. Based on information provided in Ref. 1, operator action to open the sump isolation valves will transfer ECCS pump suction to the RBES following a cold-leg break. This is because containment pressure is high enough to overcome the elevation head of the BWST. For a hot-leg break, however, the lower expected containment pressure requires the operators to also isolate the BWST before the ECCS pumps take suction from the RBES. Closure of the BWST isolation valves occurs later in the transfer sequence and requires additional time. The difference in timing is important, primarily for large- and medium-break LOCAs, and therefore cold- and hot-leg breaks must be distinguished in the model. To recognize the greater likelihood of a break in a cold leg because of the greater number of cold leg pipe segments and welds,[c] this analysis assumes a probability of 0.6 that a LOCA will occur in a cold leg.

[a]During the January 28, 1999, telephone conversation, personnel at Duke Power stated that the Oconee operators would take action when the first RBES level channel indicated that the water level in the RB was 1.2 m (4 ft). Failure to take action would therefore require failure of both channels to indicate a 1.2-m (4-ft) level.

[b]Personal communication, J. W. Minarick (SAIC) and D. M. Rasmuson (NRC), March 15, 1999.

[c]Reference 7 provides a discussion of the factors that influence the likelihood of pipe break.

RBES = 1.2 m (4 ft) at BWST Minimum Level (RBES-MIN). If transfer to the RBES is delayed, the water level in the BWST will ultimately decrease to the point where the ECCS pumps are damaged by vortexing or unacceptable NPSH. Success for this branch implies that the water level in the RB reaches 1.2 m (4 ft), satisfying the EOP BWST-to-RBES transfer requirement, in time for the operators to effect RBES transfer before ECCS pump damage occurs. The incorrectly calibrated BWST level transmitters at the three units effectively raised the indicated level at which vortexing would begin. The level at which vortexing is expected to begin was chosen as the BWST level associated with unacceptable LPI pump operation because the impact of vortexing on pump performance is expected to dominate. Based on the information included in **Additional Event-Related Information**, the impact of the slight reduction in NPSH caused by a 0.3-m (1-ft) reduction in BWST level is expected to be relatively minor. However, once vortexing begins it is expected to completely develop with only a slight additional reduction in the water level in the BWST (see, for example, the description of the loss of residual heat removal capabilities at Diablo Canyon on April 10, 1987, in Ref. 8).

Attachment A to Ref. 1 indicates that vortexing is expected to begin at a BWST water level of 0.26 m (0.85 ft) (refer to Fig. B.3.1). Considering the calibration errors described in Table B.3.1, vortexing is expected to begin, unknown to the operators, at an indicated BWST level of approximately 0.55 m (1.8 ft) for Units 1 and 2, and 0.70 m (2.3 ft) for Unit 3. To complete the transfer from the BWST to the RBES before vortexing impacts the LPI pumps, the operators must begin the transfer process at an indicated BWST level greater than 0.6 m (2 ft) (the level specified in the EOP at which the BWST must be isolated).

Based on ECCS flow rates and valve cycle times,[a] plus additional assumptions concerning initiator-specific flow rates, the time to perform an intermediate EOP step, and unit-specific average BWST calibration errors,[b] the estimated BWST indicated levels at which the RBES transfer must begin to prevent vortexing are shown in Table B.3.5.

The conditional probabilities that RB water level on both level transmitters is still less than 1.2 m (4 ft) when the BWST reaches the minimum acceptable levels listed in Table B.3.5, given the RBES level indication was less than 1.2 m (4 ft) when the water level in the BWST was 1.8 m (6 ft), were estimated using the same approach as for branch RBES-OK. These conditional probabilities are also included in Table B.3.5.

[a]Personal communication, J. W. Minarick (SAIC) and B. Abellana (Duke Power), March 10, 1999. For a large-break LOCA, an LPI flow rate of 0.38 m^3/s (6000 gpm) (two trains), a building spray flow rate of 0.19 m^3/s (3000 gpm) (two trains), and an HPI flow rate prior to operator termination of 0.088 m^3/s (1400 gpm) are estimated. Cycle times for the RBES and BWST isolation valves are 70 and ~30 s, respectively.

[b]The following flow rates were assumed in the analysis at the time of switchover: 0.57 m^3/s (9000 gpm) [large-break LOCA (LPI plus building spray)], 0.28 m^3/s (4400 gpm) [medium-break LOCA (HPI plus building spray)], and 0.088 m^3/s (1400 gpm) [small-break LOCA and feed-and-bleed cooling (HPI)]. For cold leg breaks, the analysis assumed the RBES valves must be opened 50% for the RBES to become the pump suction source. For hot leg breaks, the analysis assumed the BWST isolation valves had to completely close before the sump provided suction flow. In addition, an intermediate step in the EOP requiring building spray throttling was assumed to require 1 min. The average BWST calibration error was assumed to be -0.30 m (-1.0 ft) for Units 1 and 2 and -0.43 m (-1.4 ft) for Unit 3.

Operators Switch to RBES at BWST Minimum Level (OPS-MIN). Success for this branch implies a decision on the part of the operators to transfer the ECCS pumps to the RBES before pump damage occurs, even though the water level in the RB was less than 1.2 m (4 ft). If the water level in the RB is less than 1.2 m (4 ft) when the water level in the BWST is drawn down to 1.8 m (6 ft), the operators will find themselves outside their procedural bases—action to effect transfer to the RBES would technically be a violation of the EOP (Ref. 2) as written at the time the condition was discovered. However, the operators would be aware conceptually of the need to transfer to the sump before the BWST depletes and would know that the procedure required the transfer to be completed by the time the BWST level indicated 0.6 m (2 ft). This knowledge is expected to result in an increasing urgency (initially tempered by the understanding that some minimum RB water level was required for the pumps to operate in the recirculation mode) to transfer the ECCS pumps to the RBES as the water level in the BWST drops, ultimately resulting in such a decision. Degraded ECCS pump performance, if observed, would serve to reinforce the decision to transfer (operator burden, the need for rapid response, plus annunciator noise, particularly following a large- or medium-break LOCA, would be expected to compromise such an observation). The Technical Support Center (TSC) would be fully operational at the time for small-break LOCAs and would also be expected to reinforce the decision to transfer suction to the RBES.

The probability of not transferring the ECCS pumps cannot be rigorously estimated using contemporary Human Reliability Analysis (HRA) methods because the action is outside the procedure basis and is, in part, ad-hoc. For the purposes of this analysis it was assumed that, without TSC assistance, the operators would not begin to transfer the ECCS pumps to the RBES at an indicated BWST level of 1.8 m (6 ft). However, around an indicated BWST water level of 1.2 m (4 ft), it was assumed that there was an even chance that the operators would begin transferring the ECCS pumps to the RBES rather than waiting further for indication that the water level in the RB had risen to 1.2 m (4 ft), and that at an indicated level of 0.6 m (2 ft) the operators would likely transfer the pumps to the sump. A value of 0.5 was therefore assigned to the probability that the operators would begin to transfer suction to the RBES at an indicated BWST water level of 1.2 m (4 ft), and a value of 0.1 was assigned to the probability that the operators would begin to transfer at an indicated level of 0.6 m (2 ft). At an indicated water level of 1.8 m (6 ft), a value of 1.0 was assigned to the probability that the operators would begin to transfer to the sump. For small-break LOCAs, the TSC would also be available to aid the operators. A moderate dependency is assumed between the operators and the TSC for a decision at 1.2 m (4 ft) and greater, and a low dependency is assumed for the decision at 0.6 m (2 ft), resulting in probability estimates of 0.9, 0.3, and 0.01, at 1.8, 1.2, and 0.6 m (6, 4, and 2 ft), respectively.[a]

The probabilities that the operators, with and without support from the TSC, would fail to begin transferring the suction for the ECCS pumps to the RBES by the time the water levels in the BWST were estimated by linearly interpolating between the probabilities estimated for water levels of 0.6, 1.2, and 1.8 m (2, 4, and 6 ft). Representative operator error probabilities are shown in Table B.3.6.

Substantial uncertainty is associated with the probabilities estimated for this branch. As noted earlier, the operator action being modeled is outside the domain of contemporary HRA methods. This, plus the fact that the impact of errors in procedures have not been considered in simulator exercises, results in very little information

[a]Small-break LOCAs do not measurably contribute to the significance of this event. Assumptions concerning the probability of operator error following a small-break LOCA have little impact on the analysis results.

being available to accurately estimate such probabilities. The estimated probabilities are considered reasonable, considering the state of the art.

Operators Proceed Without Delay through Procedure (NO-DELAY). If RB water level indicates 1.2 m (4 ft) when the BWST level is 1.8 m (6 ft), the operators are expected to begin transferring the suction for the ECCS pumps to the RBES as required by the EOP. Following a hot leg break, if the operators prolong the transfer and delay isolating the BWST until its indicated level approaches 0.6 m (2 ft) (as allowed by the procedure), the ECCS pumps can also fail from vortexing. Success for this branch implies that the operators proceed expeditiously in transferring the pump suctions to the RBES. A failure probability of 0.1 was utilized for large- and medium-break LOCAs, where a delay of a few of minutes is sufficient to initiate vortexing, considering the miscalibrated BWST level transmitters. For small-break LOCAs and feed-and-bleed cooling, because of the slow BWST drain down, only a deliberate decision to delay BWST isolation until a BWST level of ~0.6 m (2 ft) is indicated will result in pump damage; a failure probability of 0.01 is assumed in these cases.

Depressurization to Allow Low-Pressure Recirculation (LPR) (DEPRESS). Medium- and small-break LOCAs and feed-and-bleed cooling require HPI for injection success. When the inventory of water in the BWST is depleted, the LPI pumps are used to take suction from the RBES and provide flow, at adequate NPSH, to the HPI pumps. Oconee procedures require the HPI pumps to be lined up in series with the LPI pumps when the water level in the BWST is at 3.0 m (10 ft). The loss of LPI pump flow at the onset of vortexing is expected to cause the HPI pumps to fail, resulting in the need to rapidly depressurize the RCS to allow use of the LPI pumps for injection. Depressurization is possible following a LOCA, provided secondary-side cooling is available (depressurization cannot be used during feed-and-bleed cooling because secondary-side cooling is unavailable). Consistent with previous precursor analyses of events at Oconee (Ref. 9), the probability of failing to depressurize the RCS to allow use of the LPI pumps for injection was assumed to be 0.1. The probability of failing to depressurize to allow LPR for the initiating events of interest are given in Table B.3.7.

LPR Recovered (LPR-REC). Success for this branch implies that LPR is recovered following an initial failure to transfer, for example, through use of the third LPI pump once transfer is complete. Failure to recover LPR would be highly dependent on the initially faulty assessment that resulted in the failure of the running LPI pumps. For a large-break LOCA, operator burden (associated with the unusual nature of the instrumentation anomalies in addition to the existence of the large-break LOCA) plus annunciator noise would be expected to delay the operating crew's realization that the LPI pumps had failed and delay diagnosis of the failure and implementation of any recovery strategy until well beyond the time that core uncovery occurs [7 min after loss of LPI (Ref. 1)]. A nonrecovery probability of 1.0 was therefore assumed for LPR-REC following a large-break LOCA.

For a medium-break LOCA, a failure probability of 0.5 was estimated for LPR-REC (this is conditional on the failure of OPS-MIN). This estimate considers the limited time available to recover recirculation cooling [15 min based on the Oconee probabilistic risk assessment (PRA) (Ref. 9) description of recovery event LLP0P3CREC], the burden imposed by the unusual nature of the failure, and the expected difficulty in analyzing the nature of the failure[a]. The potential for TSC support during some medium-break LOCAs was considered as a sensitivity analysis. The additional time and TSC support that would be available following a small-break LOCA would improve the likelihood of recovery; a failure probability of 0.1 was used with this initiator. The non-recovery probabilities for LPR for the initiating events of interest are given in Table B.3.8.

B.3.5 Analysis Results

The combined CCDP associated with the BWST level transmitter miscalibration and RB water level error over a 1-year period for recirculation-related sequences is 1.7×10^{-6} for Units 1 and 2, and 1.4×10^{6} for Unit 3 (Table 9). Because design and installation errors such as those that comprise this event are not typically addressed in PRAs (their contribution to nominal cut sets is zero), this CCDP is also the increase in the nominal CDP, or importance, for the event. The overall CCDP, considering all sequences, is therefore the estimated CDP for Oconee in a 1-year period (1.8×10^{-5}, based on the ASP models) plus the above increases, or 2.0×10^{-5} for Units 1 and 2, and 1.9×10^{-5} for Unit 3.

Although the significance of the event at Units 1 and 2 is slightly greater than at Unit 3 (a result of the higher calculated RB water level at Unit 3), the dominant sequence (6.1×10^{-7}) within the subset of recirculation-related sequences involves a medium hot leg break at Unit 3 (sequence 2-4 on Fig. B.3.5). In this sequence, when the water level in the BWST is drawn down to an indicated level of 1.8 m (6 ft) following a postulated medium-break LOCA, the indicated water level in the RB is 1.2 m (4 ft), and the operators would begin transferring the suction for the ECCS pumps to the RBES. However, if the operators delay isolation of the BWST until the water level in the BWST approaches 0.6 m (2 ft), the ECCS pumps would fail as a result of air binding. Depressurization to allow use of the LPI pumps is successful, but the operators fail to recover LPR, resulting in core damage. This sequence is highlighted on the medium-break LOCA event tree shown in Figs. B.3.4 and B.3.5 [which represents the recirculation (PB-COOL) branch in Fig. B.3.4]. The medium-break LOCA model is similar to that developed to support the analysis of LER No. 287/97-003 in Ref. 10 and is described in that analysis. (Sequences associated with the late failure of HPI, which was important in the analysis of LER No. 287/97-003, have been excluded.)

The second most dominant sequence (with a CCDP of 2.9×10^{-7}) is similar to the dominant sequence but occurs at Units 1 and 2. In addition to medium-break LOCA sequences, large-break LOCA and feed-and-bleed cooling sequences with CCDPs greater than 1.0×10^{-7} occur at all three units. As can be seen in the Table B.3.9, small-break LOCA sequences contribute to a minor extent. All small-break LOCA sequences have CCDPs below 1.0×10^{-7}.

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[a]See, for example, the analysis of LER 287/97-003 in the 1997 annual precursor report [*Precursors to Potential Severe Core Damage Accidents: 1997, A Status Report*, NUREG/CR-4674, Vol. 26, November 1998 (Ref. 10)]. In this event, two Oconee 3 HPI pumps were damaged during a reactor shutdown as a result of a low water level in the letdown storage tank. After the low HPI pump discharge pressure was observed, over a 15-min period the operators started and stopped the two pumps and operated associated valves in an attempt to recover HPI pump discharge pressure before recognizing the potential cause of the problem and securing the pumps.

The medium-break LOCA sequences were analyzed with the assumption that the TSC would not be available at the time when transfer to sump recirculation was required. The resulting medium-break LOCA CCDPs, accounting for the unavailability of the TSC, are 9.8×10^{-7} for Units 1 and 2 and 8.5×10^{-7} for Unit 3; the overall CCDP for the event is 1.7×10^{-6} at Units 1 and 2 and 1.4×10^{-6} for Unit 3 (Table B.3.9). The estimated time for BWST drawdown following a medium-break LOCA is 90 min at Oconee, and it is possible, at least for some medium-break LOCAs, that the TSC would be operational at the time of sump switchover. This potential was addressed in a sensitivity analysis that assumed the TSC was available when calculating OPS-MIN (Table B.3.6). The resulting medium-break LOCA CCDPs, accounting for the availability of the TSC, are 6.5×10^{-7} for Units 1 and 2 and 8.2×10^{-7} for Unit 3; the overall CCDP for the event reduces to 1.3×10^{-6} at each unit.

To illustrate the calculational process, definitions and probabilities for the event tree branches associated with the potential loss of sump recirculation at Unit 1 or 2 following a medium-break LOCA with an initial water level in the BWST of 14.0 and 14.8 m (46.0 and 48.5 ft) are shown in Table B.3.10. Table B.3.11 lists the sequence logic associated with the core damage sequences. The conditional probabilities for the six recirculation-related core damage sequences are shown in Tables 12 and 13.

B.3.6 References

1. LER 269/98-004, Rev. 1, "ECCS Outside Design Basis Due to Instrument Errors/Deficient Procedures," April 7, 1998.

2. Oconee Emergency Operating Procedure EP/1/A/1800/01, "Cooldown Following Large LOCA," CP-601, Revision 18, p 13.

3. LER 269/97-010, Rev. 0, "Inadequate Analysis of ECCS Sump Inventory due to Inadequate Design Analysis," January 8, 1998.

4. NRC Information Notice 96-55, *Inadequate Net Positive Suction Head of Emergency Core Cooling and Containment Heat Removal Pumps under Design Basis Accident Conditions*, October 22, 1996.

5. *Rates of Initiating Events at U.S. Nuclear Power Plants: 1987 - 1995*, NUREG/CR-5750, February 1999.

6. *Westinghouse Reactor Protection System Unavailability, 1984 - 1995*, NUREG/CR-5500, Vol. 2, *in press*.

7. H. M. Thomas, "Pipe and Vessel Failure Probability," *Reliability Engineering*, 2: p 83–124 (1981).

8. *Loss of Residual Heat Removal System*, NUREG-1269, June 1987, Appendix C, p. 4.

9. Oconee Nuclear Station Units 1, 2 and 3, *IPE Submittal Report*, Rev. 1, December 1990.

10. *Precursors to Potential Severe Core Damage Accidents: 1997, A Status Report*, NUREG/CR-4674, Vol. 26, November 1998.

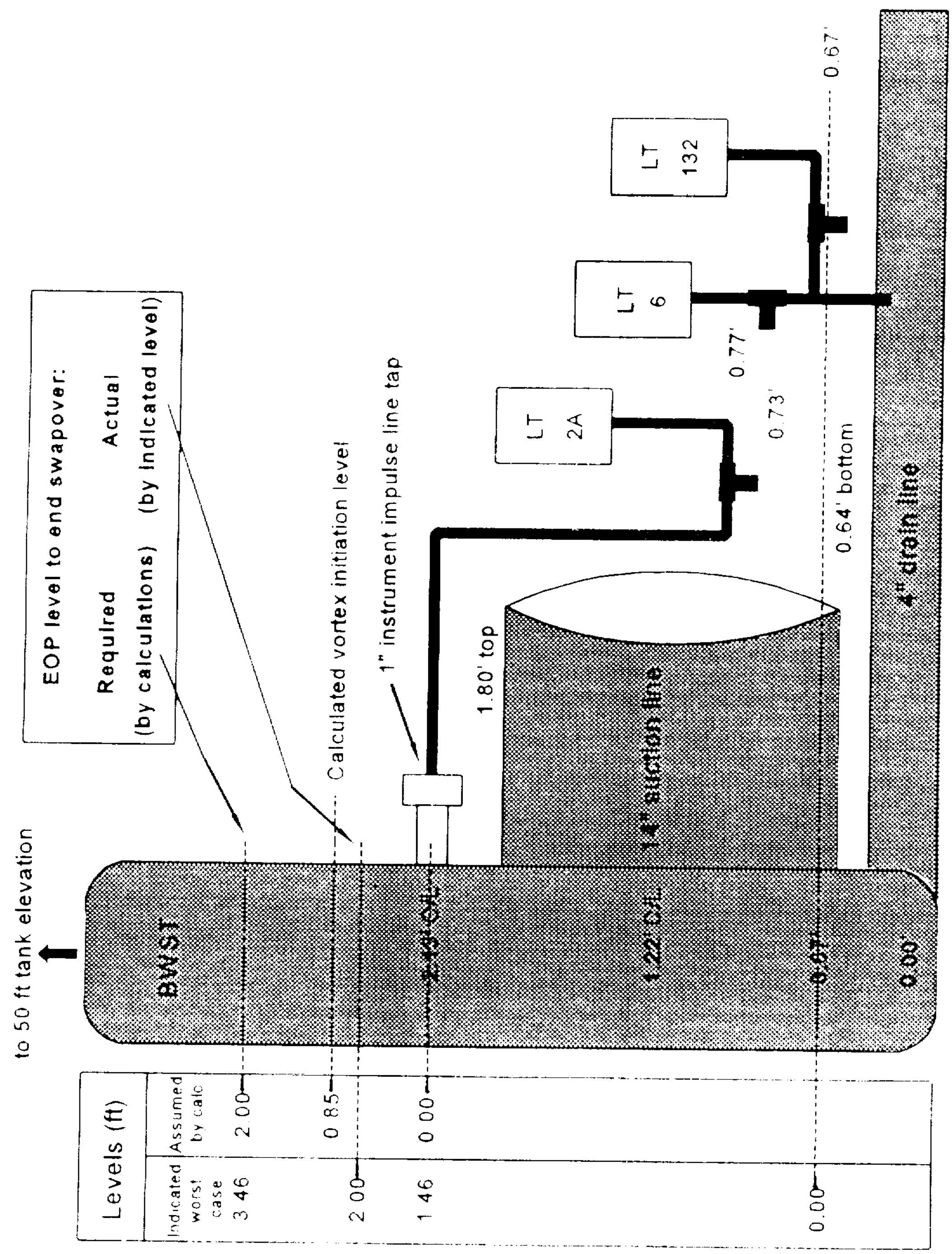

Fig. B.3.1 Borated water storage tank level instrument arrangement (*Source*: LER 269/98-004, Rev. 1). Indicated worst case is for Unit 3. BWST is borated water storage tank, C/L is center line, EOP is emergency operating procedure, and LT is level transmitter.

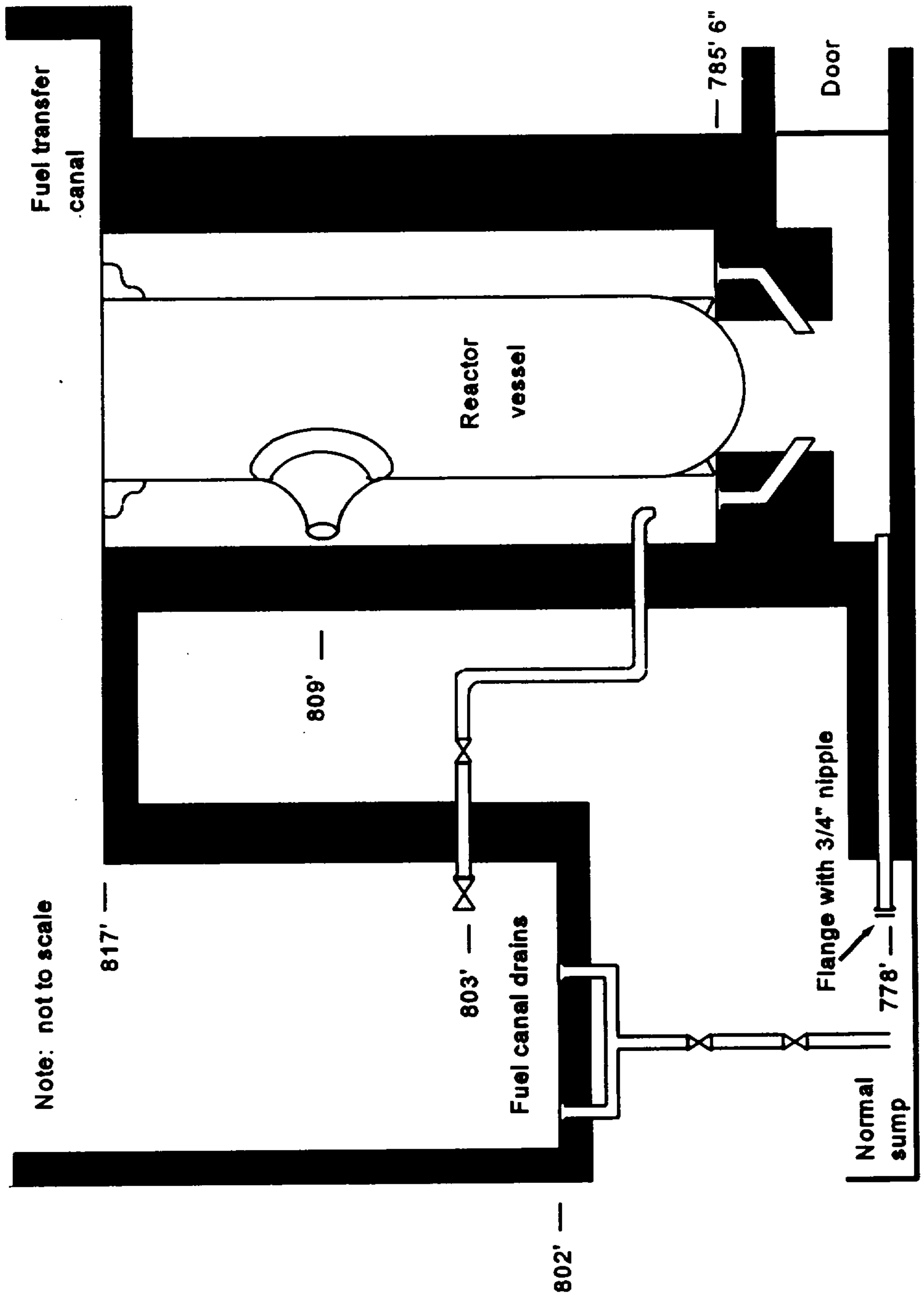

Fig. B.3.2 Interior structures in the reactor building (*Source:* LER 269/98-010, Rev. 0).

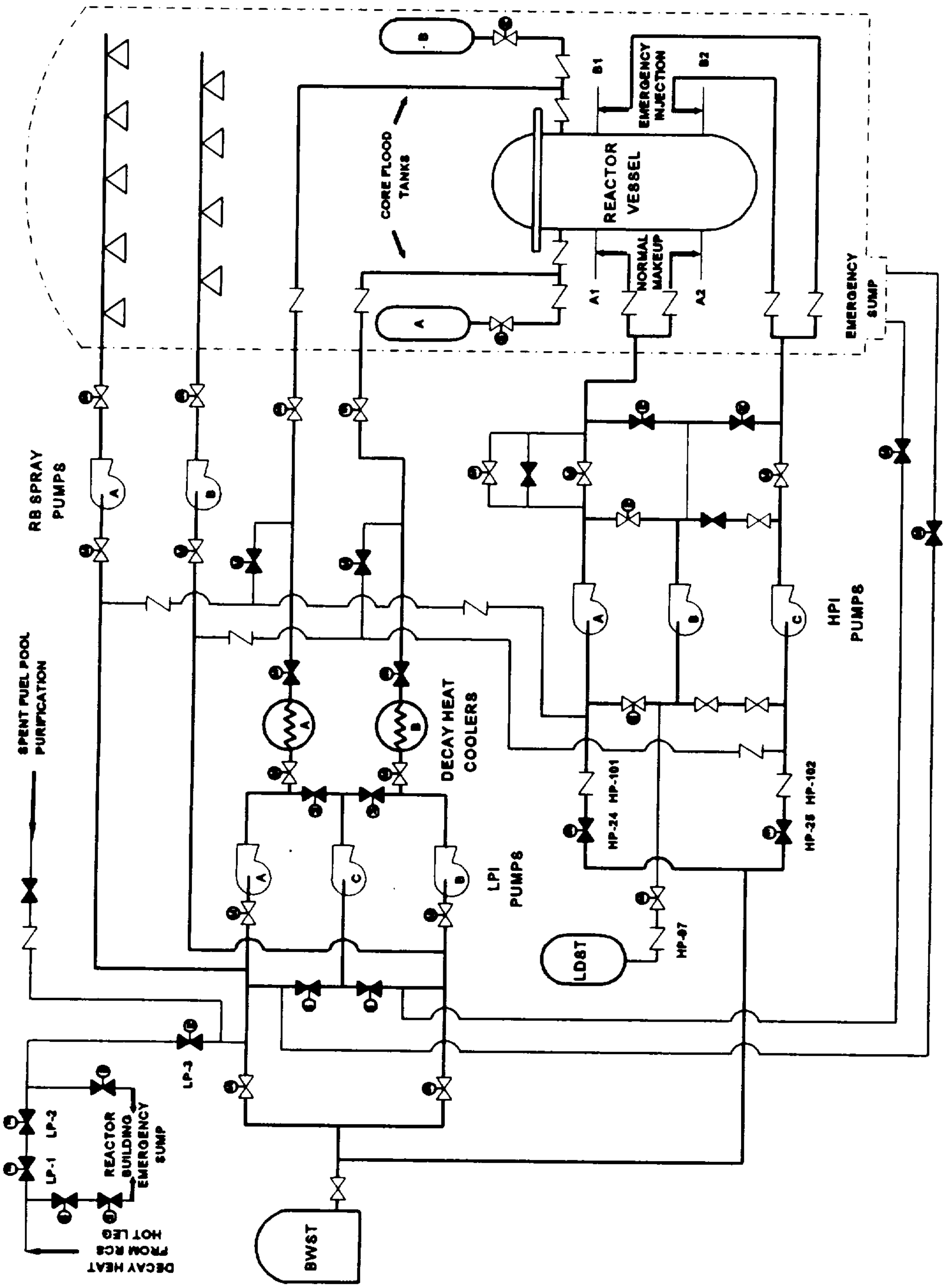

Fig. B.3.3 Flow diagram of the emergency core cooling system at Oconee (*Source: Oconee 2 Final Safety Analysis Report*). BWST is borated water storage tank, HPI is high-pressure injection, LDST is letdown storage tank, LPI is low-pressure injection, and RB is reactor building.

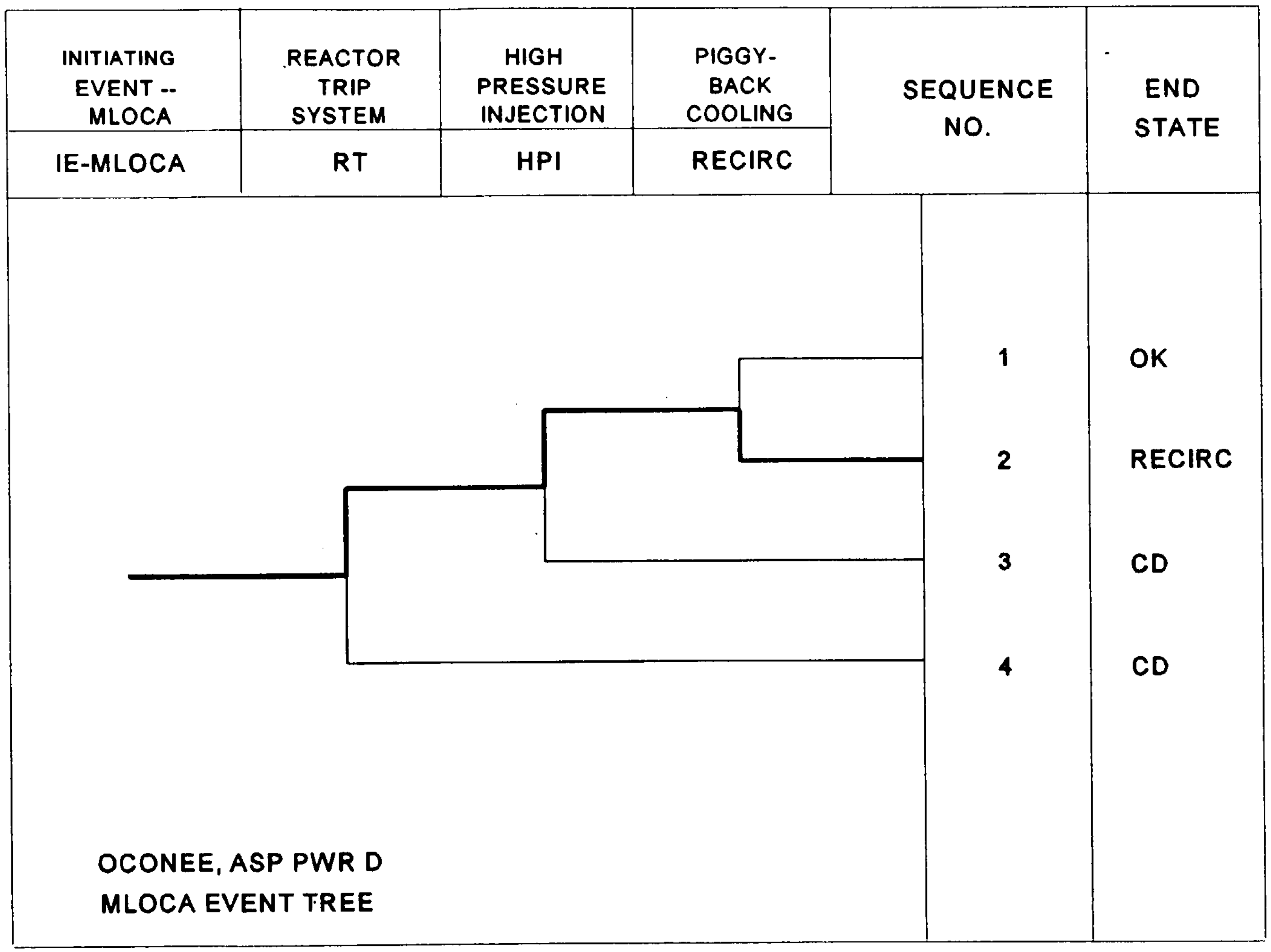

Fig. B.3.4 Event tree for medium-break LOCAs at Oconee.

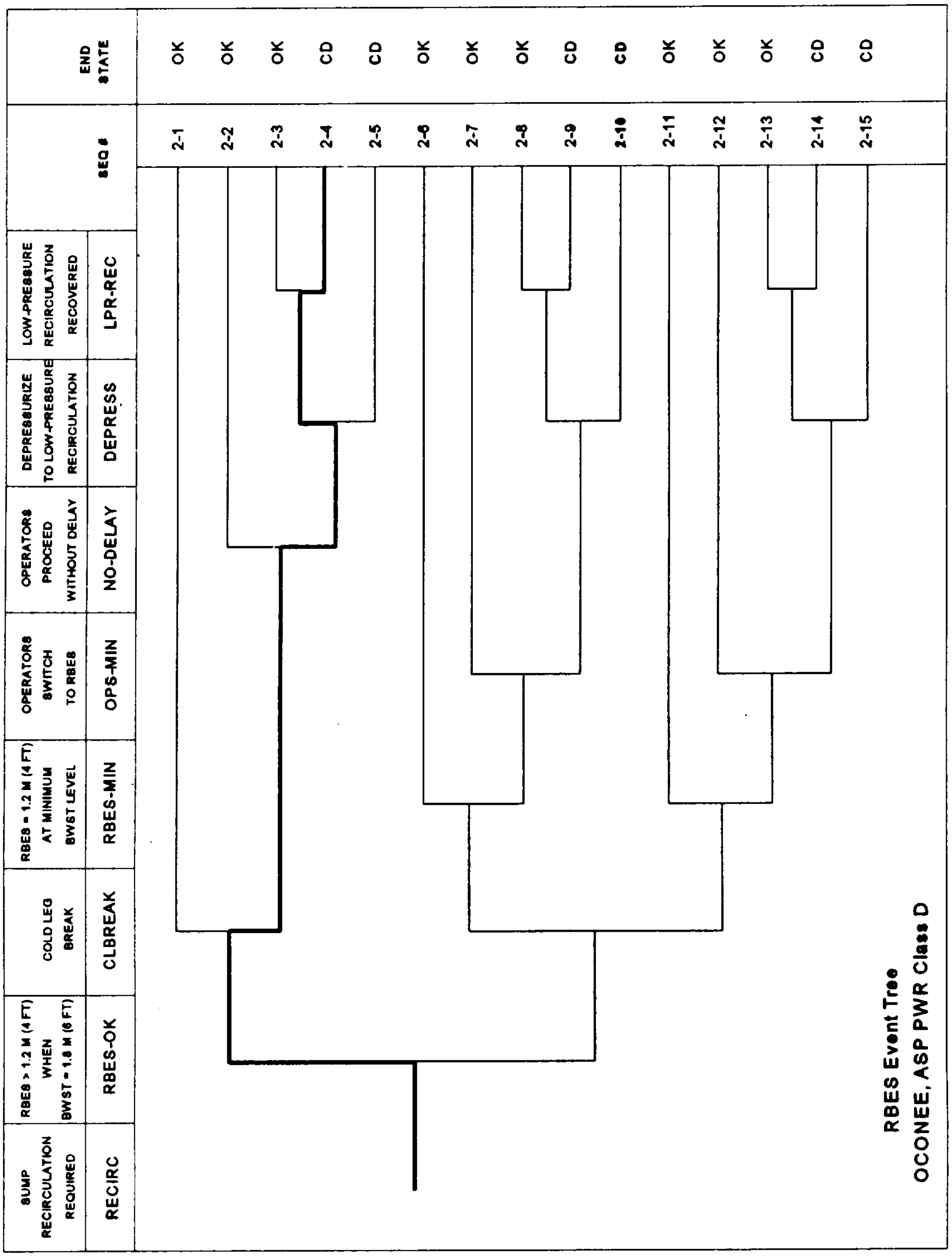

Fig. B.3.5 Event tree for failure to transfer the emergency core cooling system pumps to the reactor building emergency sump (RBES). BWST is borated water storage tank.

Table B.3.1. BWST Level Transmitter Test Tee – Impulse Line Elevation Errors

Unit	Elevation error in BWST level transmitters [m (ft)]		
	LT 2A	LT 6	LT 132
Unit 1	-0.234 (-0.77)[a]	-0.308 (-1.01)[a]	-0.287 (-0.94)[a]
Unit 2	-0.296 (-0.97)[a]	-0.335 (-1.10)[a]	-0.329 (-1.08)[a]
Unit 3	-0.415 (-1.36)	-0.427 (-1.40)	-0.445 (-1.46)

[a] NRC staff, ASP program staff, and personnel from Duke Power, teleconference, January 28, 1999.

Table B.3.2. Definitions and Probabilities for Event Tree Branches for LER No. 269/98-004

Branch name	Description	Failure probability
IE-	Initiating Event	Table B.3.3
RT	Reactor Trip	5.5 E-006[a]
HPI	High Pressure Injection	2.4 E-004[a]
RECIRC	Sump Recirculation Required BWST water level at 14.0 m (46.0 ft) BWST water level at 14.8 m (48.5 ft)	1.0 E-001 9.0 E-001
RBES-OK	RBES Level ≥ 1.2 m (4 ft) when BWST Level = 1.8 m (6 ft)	Table B.3.4
CLBREAK	Cold Leg Break	4.0 E-001
RBES-MIN	RBES = 1.2 m (4 ft) at BWST Minimum Water Level	Table B.3.5
OPS-MIN	Operators Switch to RBES at BWST Minimum Water Level	Table B.3.6
NO-DELAY	Operators Proceed Without Delay through Procedure	1.0 E-001
DEPRESS	Depressurization to Allow LPR	Table B.3.7
LPR-REC	LPR Recovered	Table B.3.8

[a] System failure probability estimated using Oconee ASP model fault trees.

Table B.3.3. Probability of Requiring Sump Recirculation for the Different Initiating Events During a 1-year Period (IE–)

Initiating event	Description	Probability of requiring sump recirculation
IE-LLOCA	Large-break LOCA	5.0 E-006
IE-MLOCA	Medium-break LOCA	4.0 E-005
IE-SLOCA	Small-break LOCA	9.2 E-005
IE-F/B	Feed-and-bleed (transients)	2.4 E-005

Table B.3.4. Probability that Neither RB Water Level Channel will Indicate 1.2 m (4 ft) (RBES-OK)

Unit	Initial BWST level	Probability that neither RB water level channel indicates 1.2 m (4 ft)
Oconee 1 and 2	14.0 m (46 ft) (10% of the time)	0.74
	14.8 m (48.5 ft) (90% of the time)	0.55
Oconee 3	14.0 m (46 ft) (10% of the time)	0.18
	14.8 m (48.5 ft) (90% of the time)	0.064

Table B.3.5. Minimum Acceptable BWST Levels to Initiate RBES Transfer and Conditional Probability that RB Level Will Not Indicate 1.2 m (4 ft) (RBES-MIN)

Initiating event	Unit	Minimum acceptable BWST level to initiate RBES transfer [m (ft)]	Conditional probability that RB level will not indicate 1.2 m (4 ft) [initial BWST level = 14.8 m (48.5 ft)]	Conditional probability that RB level will not indicate 1.2 m (4 ft) [initial BWST level = 14.0 m (46.0 ft)]
Large-break LOCA (cold leg)	1, 2	0.722 (2.37)	0.19	0.62
	3	0.844 (2.77)	0.022	0.24
Large-break LOCA (hot leg)	1, 2	1.35 (4.43)	0.39	0.85
	3	1.47 (4.83)	0.10	0.63
Medium-break LOCA (cold leg)	1, 2	0.640 (2.10)	0.17	0.59
	3	0.762 (2.50)	0.018	0.20
Medium-break LOCA (hot leg)	1, 2	0.945 (3.10)	0.25	0.70
	3	1.07 (3.50)	0.038	0.34
Small-break LOCA (cold leg)	1, 2	0.61 (2.0)[a]	0.17	0.58
	3	0.710 (2.33)	0.016	0.18
Small-break LOCA (hot leg)	1, 2	0.689 (2.25)	0.18	0.61
	3	0.808 (2.65)	0.020	0.22
Feed-and-bleed cooling	1, 2	0.689 (2.25)	0.18	0.61
	3	0.808 (2.65)	0.020	0.22

[a]Based on procedure.

Table B.3.6. Probability of Operator Failure to Transfer ECCS Pumps (OPS-MIN)

Initiating event	Unit	Minimum acceptable BWST level to initiate RBES transfer [m (ft)]	Probability of operator error without TSC support	Probability of operator error with TSC support
Large-break LOCA (cold leg)	1, 2	0.722 (2.37)	0.14	0.14
	3	0.844 (2.77)	0.20	0.20
Large-break LOCA (hot leg)	1, 2	1.35 (4.43)	0.63	0.63
	3	1.47 (4.83)	0.76	0.76
Medium-break LOCA (cold leg)	1, 2	0.640 (2.10)	0.11	0.01
	3	0.762 (2.50)	0.16	0.09
Medium-break LOCA (hot leg)	1, 2	0.935 (3.10)	0.27	0.17
	3	1.07 (3.50)	0.36	0.22
Small-break LOCA (cold leg)	1, 2	0.61 (2.0)[a]	0.01	0.01
	3	0.710 (2.33)	0.023	0.023
Small-break LOCA (hot leg)	1, 2	0.689 (2.25)	0.02	0.02
	3	0.808 (2.65)	0.044	0.044
Feed-and-bleed cooling (cold leg)	1, 2	0.689 (2.25)	0.01	0.01
	3	0.808 (2.65)	0.23	0.23
Feed-and-bleed cooling (hot leg)	1, 2	0.689 (2.25)	0.02	0.02
	3	0.808 (2.65)	0.044	0.044

[a]Based on procedure.

Table B.3.7. Probability of failing to depressurize to allow LPR (DEPRESS)

Initiating event	Probability of failing to depressurize to allow LPR
IE-LLOCA	0.0 E+000
IE-MLOCA	1.0 E-001
IE-SLOCA	1.0 E-001
IE-F/B	1.0 E+000

Table B.3.8. Probability of Failure to Recover LPR (LPR-REC)

Initiating event	Probability of failure to recover LPR
IE-LLOCA	1.0 E+000
IE-MLOCA	5.0 E-001
IE-SLOCA	1.0 E-001
IE-F/B	1.0 E-001

Table B.3.9. Estimated CCDPs from Sequences that Require Recirculation for LER No. 361/98-003

Initiating Event	Estimated CCDPs from Sequences that Require Recirculation	
	Unit 1 and Unit 2	Unit 3
Large-break LOCA	4.6 E-007	2.2 E-007
Medium-break LOCA	9.8 E-007	8.5 E-007
Small-break LOCA	6.2 E-008	6.7 E-008
Feed-and-bleed cooling	1.8 E-007	2.4 E-007
Total	**1.7 E-006**	**1.4 E-006**

Table B.3.10. Definitions and Probabilities for Event Tree Branches given a Medium-Break LOCA at Unit 1 or 2 for LER No. 269/98-004

Branch name	Description	Failure Probability	
		14.0 m (46.0 ft) BWST level	14.8 m (48.5 ft) BWST level
MLOCA	Initiating Event – Medium-Break Loss of Coolant Accident	4.0 E-005	4.0 E-005
RT	Reactor Trip	5.5 E-006	5.5 E-006
HPI	High Pressure Injection	2.4 E-004	2.4 E-004
RECIRC	Sump Recirculation Required	1.0 E-001	9.0 E-001
RBES-OK	RBES Level ≥ 1.2 m (4 ft) when BWST Level = 1.8 m (6 ft)	7.4 E-001	5.5 E-001
CLBREAK	Cold Leg Break	4.0 E-001	4.0 E-001
RBES-MIN	RBES = 1.2 m (4 ft) at BWST Minimum Water Level (Cold-Leg Break)	5.9 E-001	1.7 E-001
	RBES = 1.2 m (4 ft) at BWST Minimum Water Level (Hot-Leg Break)	7.0 E-001	2.5 E-001
OPS-MIN	Operators Switch to RBES at BWST Minimum Water Level (Cold-Leg Break)	1.1 E-001	1.1 E-001
	Operators Switch to RBES at BWST Minimum Water Level (Hot-Leg Break)	2.7 E-001	2.7 E-001
NO-DELAY	Operators Proceed Without Delay through Procedure	1.0 E-001	1.0 E-001
DEPRESS	Depressurization to Allow LPR	1.0 E-001	1.0 E-001
LPR-REC	LPR Recovered	5.0 E-001	5.0 E-001

Table B.3.11. Sequence Logic for MLOCA Sequences for LER No. 361/98-003

Event tree name	Sequence number	Logic
MLOCA + RECIRC	2-4	/RT, /HPI, /RBES-OK, CLBREAK, NO-DELAY, /DEPRESS, LPR-REC
MLOCA + RECIRC	2-5	/RT, /HPI, /RBES-OK, CLBREAK, NO-DELAY, DEPRESS
MLOCA + RECIRC	2-9	/RT, /HPI, RBES-OK, /CLBREAK, RBES-MIN, OPS-MIN, /DEPRESS, LPR-REC
MLOCA + RECIRC	2-10	/RT, /HPI, RBES-OK, /CLBREAK, RBES-MIN, OPS-MIN, DEPRESS
MLOCA + RECIRC	2-14	/RT, /HPI, RBES-OK, CLBREAK, RBES-MIN, OPS-MIN, /DEPRESS, LPR-REC
MLOCA + RECIRC	2-15	/RT, /HPI, RBES-OK, CLBREAK, RBES-MIN, OPS-MIN, DEPRESS

Table B.3.12. Sequence Conditional Probabilities for MLOCA for LER No. 361/98-003
[Unit 1 or 2 with Initial BWST Level of 14.8 m (48.5 ft) Only]

Event tree name	Sequence number	Conditional core damage probability (CCDP)[a]	Core damage probability (CDP)[b]	Importance (CCDP-CDP)	Percent contribution
RECIRC	2-4	2.9 E-007	0.0	2.9 E-007	37.7
RECIRC	2-5	6.5 E-008	0.0	6.5 E-008	8.4
RECIRC	2-9	1.0 E-007	0.0	1.0 E-007	13.0
RECIRC	2-10	2.2 E-008	0.0	2.2 E-008	2.9
RECIRC	2-14	2.4 E-007	0.0	2.4 E-007	31.2
RECIRC	2-15	5.3 E-008	0.0	5.3 E-008	6.9
Total (all sequences)		**7. 7 E-007**	**0.0**	**7.7 E-007**	

[a]Sequences shown only.
[b]Because design and installation errors such as those that comprise this event are not typically addressed in PRA, their contribution to nominal sequences is zero.

Table B.3.13. Sequence Conditional Probabilities for MLOCA for LER No. 361/98-003
[Unit 1 or 2 with Initial BWST Level of 14.0 m (46 ft) Only)]

Event tree name	Sequence number	Conditional core damage probability (CCDP)[a]	Core damage probability (CDP)[b]	Importance (CCDP-CDP)	Percent contribution
RECIRC	2-4	1.9 E-008	0.0	1.9 E-008	9.2
RECIRC	2-5	4.3 E-009	0.0	4.3 E-009	2.1
RECIRC	2-9	5.1 E-008	0.0	5.1 E-008	24.7
RECIRC	2-10	1.1 E-008	0.0	1.1 E-008	5.3
RECIRC	2-14	9.9 E-008	0.0	9.9 E-008	48.0
RECIRC	2-15	2.2 E-008	0.0	2.2 E-008	10.7
Total (all sequences)		**2.1 E-007**	**0.0**	**2.1 E-007**	

[a]Sequences shown only
[b]Because design and installation errors such as those that comprise this event are not typically addressed in PRA, their contribution to nominal sequences is zero.

B.4 LER No. 316/98-005

Event Description: A postulated break in a Unit 2 main steam line could degrade the ability of the adjacent CCW pumps to perform their function

Date of Event: July 14, 1998

Plant: Donald C. Cook Nuclear Plant, Unit 2

B.4.1 Event Summary

On July 15, 1998, with Donald C. Cook Nuclear Plant, Units 1 and 2 (Cook 1 and 2) in cold shutdown, it was determined that a postulated crack in a Unit 2 main steam line could degrade the ability of the adjacent component cooling water (CCW) pumps to perform their design function.[1] The CCW pumps for both units are adjacent to one another in a semi-enclosed area in the Auxiliary Building. Next to the area where the pumps are located is a pipe chase enclosing two Unit 2 main steam lines and a main feedwater (MFW) line. This pipe chase can be accessed through any one of three doors. Although the pipe chase walls provide a qualified high energy line break (HELB) barrier, these doors are not designed to be watertight or pressure-retaining. The CCW pump motors and other equipment are not qualified for a high temperature/high humidity environment. As a result, if the postulated HELB were to occur, the potential would exist for one or both units to suffer a total loss of CCW.

The estimated increase in the core damage probability (i.e., importance) associated with this issue for a one-year period at Cook 2 is 3.0×10^{-6}. The importance associated with this issue at Cook 1 is $< 10^{-6}$.

B.4.2 Event Description

On July 15, 1998, with both units in Operating Mode 5, cold shutdown, the licensee determined that a postulated crack in a Unit 2 main steam line could degrade the ability of adjacent CCW pumps for both units to perform their design function. The condition was reported on August 14, 1998, as an unanalyzed condition in Interim LER 316/98-005, Rev. 0, (Ref. 1).

The CCW pumps for both units are adjacent to one another in a semi-enclosed area in the Auxiliary Building. Next to the area where the CCW pumps are located is a pipe chase enclosing two Unit 2 main steam lines and a MFW line, which can be accessed through any one of three access doors. Although the walls of the pipe chase provide a qualified HELB barrier, these doors are not designed to be watertight or pressure-retaining. The CCW pump motors and other equipment are not qualified for the high temperature/high humidity environment that would exist following an HELB.

There are five CCW pumps for the two units. Each unit has two dedicated, 100% capacity, redundant, CCW pumps and associated systems. The fifth pump is available to supply either unit and can be powered from any safety-related electrical bus. For fire protection considerations, the fifth pump is grouped with the Unit 1 pumps. The Unit 2 pumps are separated from the Unit 1 pumps and the spare pump by a three-hour fire barrier. This barrier is approximately seven feet tall, while the room containing the CCW pumps (CCW Pump Room) is

~4.3 m (14 ft) tall. The barrier, which extends from the CCW Pump Room wall to beyond the location of the pumps, is ~9.1 m (30 ft) long. In the place where a sixth CCW pump could have been located, outside of the CCW Pump Room, is a small area where the Unit 2 main steam (two lines) and MFW (one line) lines pass the CCW Pump Room. These pipes are oriented in the vertical direction as they pass the CCW Pump Room. These lines are isolated from the CCW Pump Room by concrete walls. Access is provided to these lines from the CCW Pump Room through three industrial style personnel doors [~0.9 × 2 m (3 ft × 7 ft)]. These doors are not designed to be watertight or pressure-retaining.

B.4.3 Additional Event-Related Information

As stated above, there are two main steam lines and one MFW line running through the pipe chase of interest. This pipe chase contains only large bore main steam and MFW piping. There are no small bore high energy branch lines in this area. The licensee's investigations found that there are no high stress pipe segments in this area which are vulnerable to cracks or breaks. There are three access doors between the pipe chase and the CCW Pump Room, which open into the CCW Pump Room. The length of piping adjacent to each of the doors is about 6.1–9.1 m (20–30 ft), which means that about 18–27 m (60–90 ft) of piping are situated near the doors.[2]

References 2 and 3 provide the following information: The pipe chase in question communicates with a steam tunnel, which is a large area. A postulated failure of the high energy piping in this large area could send steam into the pipe chase adjoining the CCW Pump Room. If the pressure increase due to the postulated piping failure were high enough, then the doors from the pipe chase to the CCW Pump Room could open, and allow steam to enter that room. However, based on Refs. 2 and 3, it is known that one end of the steam tunnel is open to the turbine building. Therefore, the turbine building provides a large potential escape path for steam generated by postulated piping breaks in the steam tunnel. The other end of the steam tunnel is also open to a very large, potential steam escape volume.

B.4.4 Modeling Assumptions

The data and approach used to estimate piping failure frequencies are as follows:

Type of piping failure (crack, leak, or rupture)

Reference 4 [*Reliability of Piping System Component, Framework for Estimating Failure Parameters from Service Data, SKI (Swedish Nuclear Power Inspectorate (SKI) Report 97: 26)*] classifies pipe failures as cracks, leaks, and ruptures. For the scenario considered for the analysis of the condition at the Cook plant, according to Ref. 5 (*Expert Judgement on Capability of Non-EQ CCW Pumps at DC Cook*), only pipe ruptures are capable of creating a pressure increase that is capable of failing the doors to the pipe chase. Cracks and leaks are not capable of generating pressures that are large enough to fail the doors open. Steam flow around closed doors (i.e., gaps under the door) is not capable of failing the CCW pumps, since steam will tend to enter the large open areas at the ends of the pipe chase rather than flow into the CCW Pump Room around the doors. Even if some steam enters the CCW Pump Room through gaps around the doors, due to the buoyant forces, the steam will rise toward the ceiling rather than move toward the CCW pumps. Therefore only feedwater or steam line ruptures, rather than cracks or leaks, were considered in the frequency estimation.

Location of piping ruptures capable of causing CCW pump failure

This analysis assumed that only the breaks at piping elbows which are located in the immediate vicinity of the CCW Pump Room doors would be capable of generating a pressure that could cause the doors to fail open. The basis for this conclusion is summarized as follows. If an HELB were to occur at or near an elbow in the immediate vicinity of the pipe chase, there could be a local pressure spike that could open one or more doors. However, the capability of breaks at elbows away from the pipe chase was not considered, since the large open areas at the ends of the pipe chase would result in low pressure spikes at the doors. Reference 5 provides details on the basis for this assumption.

Selection of data sources (plant-specific versus U.S. and International)

Piping failures at nuclear plants are rare events. Therefore, the use of plant-specific information and the Bayesian approach with a non-informative prior (zero failures in main steam lines and MFW lines in approximately 50 calendar years for Cook 1 and Cook 2) would lead to an overly conservative piping failure frequency of 0.01/calendar-year (½/51). The licensee's individual plant examination (IPE)[10] uses a value of 3.4×10^{-4}/year for the combined frequency of main steam line breaks and feedwater line breaks. However, no basis could be found for this value. Therefore, several sources of U.S. and international operating experience data were used to select appropriate data for a realistic estimate of pipe failure frequency.[4,6,7,8,9] Since the frequency calculations use data from other nuclear plants to estimate the frequencies for Cook, the conditions of the main steam or MFW piping or conditions pertaining to failure events might not be identical to conditions found at Cook. However, randomness and the use of a significantly larger population of data would result in a more realistic estimate than using Cook operating experience only. Reference 4 refers to the most up-to-date and comprehensive data source, with 2356 pipe failure records of U.S. and international events. Therefore, insights provided in Ref. 4 were used to screen the U. S. data. References 6, 7, and 8 were used to identify data for calculating the rupture frequency. These three references include only U.S. operating experience. These references were chosen over Ref. 4, since this report does not provide details on events and the database itself is not available.

Piping reliability attributes

Piping reliability (or the failure frequency) depends on a large number of attributes. For example, the segments of the main steam and MFW lines in the pipe chase at the Cook plant consist of carbon steel piping with large diameters. The MFW piping in the pipe chase is 51-cm (20-in) Schedule 80 piping, whose normal operating temperature is 216°C (421°F) and the normal operating pressure is 7.07 Mpa (1025 psig). Such variations in design and operating characteristics which influence the piping reliability need to be factored into the piping frequency calculation, to the extent practical (e.g., availability of data breakdowns by reliability influence factors). Table 4-2 of Ref. 4 identifies piping reliability attributes as:

- Pipe diameter, wall thickness, and ratio;
- Piping system type which implicitly accounts for process medium (e.g, feedwater, steam);
- Piping material (e.g., stainless steel, carbon steel);

- Process parameters (e.g., temperatures, pressures); and
- Design/construction/installation (e.g., welding techniques).

Data tabulated in Ref. 4 showed a significant difference in the number of ruptures between those that occurred in large-bore [> 25 cm (~10 in.) in diameter] stainless steel pipes (zero failures) and those that occurred in all balance-of-plant, large-bore piping, which is typically made of carbon-steel (33 failures). The above attributes, which have a propensity to affect the piping failure frequency and cause, were examined for the specific case of the piping in the Unit 2 pipe chase. For these reasons, only carbon steel large diameter piping carrying single-phase feedwater (for feedwater pipes) or high-quality main steam (for main steam pipes) was considered in selecting failure events and operating experience.

Failure experience for the main steam line break frequency estimation was limited to pipes carrying high-quality steam since: (a) operating experience indicates that main steam pipes carrying high-quality steam have similar (lower) failure rates , and (b) one of the significant contributing failure mechanisms (erosion/corrosion) is highly unlikely to occur in piping for steam that does not carry water droplets. The use of operating experience data for feedwater lines was limited to piping that carries single-phase flow, since experience has shown a significant difference between the failure rate of piping carrying single-phase flow and piping carrying two-phase flow. According to Tables B.5-5 and Tables B.6-5 of Ref. 4, all ruptures in condensate and feedwater lines whose diameter was greater than ~10 cm (4 in) were caused by erosion and corrosion. However, rather than selecting experience involving piping with diameters greater than 10 cm (4 in), experience pertaining to piping whose diameter exceeded 25 cm (10 in) was used. This was justified since process media, systems, and the process parameters are more closely related to the large bore piping in the Unit 2 pipe chase.

Pooling PWR and BWR operating experience data

The balance-of-plant (BOP) of pressurized water reactors (PWRs) and the reactor coolant pressure boundary of boiling water reactors (BWRs) contain carbon steel piping. The operating experience data (failures and root causes of those failures), as well as process parameters (temperatures and pressures) were considered to determine whether the large bore piping experience of the BWR and PWR populations could be pooled. In U.S. commercial reactor operational history, there has been one MFW pipe rupture in a large bore pipe (Quad Cities 2 – 8/75) in approximately 550 critical-years of BWR operation, and three MFW ruptures (Indian Point 2 – 11/73, Maine Yankee – 01/83, and Surry – 12/86) in approximately 1100 critical-years of PWR operation. No main steam line failures have occurred in large-bore carbon steel piping. Based on the above, it was concluded that there is no statistically significant difference in failure probabilities between PWR and BWR piping. In terms of the attributes that contribute to failures, both BWRs and PWRs have large-bore carbon-steel piping that carry single-phase flow (for MFW) and high-quality steam (for main steam). Therefore, PWR and BWR data were pooled to perform rupture frequency estimations.

Total operating experience

For both PWRs and BWRs, based on Ref. 6 (NUREG/CR-5750) and Ref. 17 (NUREG-1272), the total operating experience is approximately 1600 critical-years.

Piping Failures

Piping reliability attributes discussed earlier in this document were used to identify the pipe ruptures that were used in the frequency calculations. Zero failures in main steam lines and two failures in MFW lines were used in the pipe failure frequency estimates. The basis for these values is as follows:

> References 4, 6, and 7 report many failures in main steam lines. However, there were no main steam line ruptures in carbon steel large-bore piping that carry high-quality steam in U.S. reactors during the period covered by Ref.s 4, 6, and 7 (1970–1998).
>
> Between 1970 and 1998, there were two MFW pipe failures in large-bore piping in U.S. nuclear power plants. Each of these failures was reviewed to determine whether there were any associated unique factors that would make them inapplicable to the potential for breaks at the welds, elbows, or straight piping in the vicinity of the pipe chase.
>
> At Surry, the feedwater pipe rupture occurred at a carbon steel elbow in the 46-cm (18-in) suction pipe to the "A" main feed pump. The ruptured feedwater piping was attributed to pipe wall thinning due to an erosion/corrosion phenomenon. When the reliability attributes stated earlier were used, there was no basis to conclude that this failure was not applicable to Cook (Refs. 11 and 12).
>
> In the Indian Point 2 event, a feedwater line rupture occurred in an 46-cm (18-in) diameter pipe with 2.54-cm (1-in) wall thickness at a fillet weld between the feedwater line and the end plate, which was welded into the penetration sleeve in the containment. The rupture was attributed to water hammer. The LER for this event identified several mechanisms (sudden closure of regulating valves, check valve malfunction, water-steam interaction in the line segment adjacent to the steam generator). Just like Indian Point 2 , the MFW lines at Cook could experience one or more of these transients during a random event. During a water hammer event, breaks could occur at locations such as welds and bends. Therefore, it was concluded that this type of occurrence was applicable to Cook. Since this MFW line break occurred in 1973, in consideration of changes to pipe break prevention programs instituted since 1973 (e.g., erosion/corrosion programs), it was necessary to consider the appropriateness of this 1973 failure in frequency calculations. Based on Ref. 18, the database and the knowledge base on pipe failures were too limited for drawing conclusions relating to trends in pipe rupture frequency, therefore it was appropriate to include this failure in the frequency estimation.

Frequency of MFW and main steam piping ruptures

Based on the above information regarding the number of failure events and operating years for large bore [> 25 cm (10 in) diameter] carbon steel piping which is not connected to small bore piping, but is carrying single-phase feedwater or high-quality steam, the estimated pipe rupture frequencies used in this analysis were 1.6×10^{-3}/critical-year (2.5/1600) for MFW piping and 3.1×10^{-4}/ critical-year (0.5/1600) for main steam piping. A Jefferey's non-informative prior was used in this Bayesian update.

Adjusting the frequency by the criticality factor

The criticality factor for Cook 2 is 0.68 (Ref. 6). The criticality factor for Unit 2 was used in this analysis to calculate the initiating event frequency rather than the factor for Unit 1 because the piping in the pipe chase of concern was associated with Unit 2. As a result, the estimated frequencies were 2.1×10^{-4} per year ($0.68 \times 3.1 \times 10^{-4}$) for steam line breaks/leaks, and 1.0×10^{-3} per year ($0.68 \times 1.6 \times 10^{-3}$) for feedwater line breaks/leaks.

Length of MFW piping and main steam piping at Cook

Based on input provided by the licensee,[13] the length of MFW piping whose diameter exceeds 25 cm (10 in) was estimated to be ~396 m (1300 ft). This 396 m (1300 ft) included feedwater piping that starts at the MFW pumps and ends at the steam generators. However, since the pipe rupture at Surry occurred in condensate piping (suction side of the MFW pumps), the length of condensate piping that met the reliability attributes identified earlier was also added to the total piping length. Based on the UFSAR, this total was estimated to be ~366 m (1200 ft). [Note: In order to be consistent with the reliability attributes (e.g. process parameters such as pressure and temperature), condensate piping from feedwater heaters 1A, 1B, and 1C to the MFW pumps was included in this estimate]. Therefore, the estimated total length of feedwater and condensate piping considered was 762 m (2500 ft).

According to Ref. 13, the total length of large bore main steam piping is ~1463 m (4800 ft). However, whether the 1463 m (4800 ft) of piping carries high-quality main steam could not be ascertained. Therefore, information provided in the UFSAR[3] was used to estimate the length of large bore [>25-cm (10-in) diameter] main steam piping—approximately 610 m (2000 ft).

Frequency of HELB in the vicinity of the pipe chase (HELB-PC)

It was necessary to adjust the estimated frequency of the pipe breaks for the total plant to account for the limited amount of piping in the pipe chase and its vicinity whose rupture would be capable of causing the CCW Pump Room doors to fail open. As stated before, steam from a pipe break anywhere in the tunnel could potentially enter the pipe chase. However, due to the large potential escape paths, based on expert judgement provided in Ref. 5, it was assumed that only breaks which occurred in the piping in the vicinity of the doors to the CCW Pump Room would be capable of opening any one of the three doors. The length of piping adjacent to each of the doors is about 6.1–9.1 m (20–30 ft), which means a total of about 18–27 m (60–90 ft) is situated near the doors.[2] Therefore, the length of the pipes in the pipe chase was assumed to be 7.6 m (25 ft) for the single MFW line and 15 m (50 ft) for the main steam lines. Considering past operating experience, it was assumed that breaks could occur at welds and bends. Even though ruptures are less likely in straight pipe runs free of connections to smaller diameter pipes and welds, they could occur at locations downstream of straight runs and downstream of bends and welds. Therefore, in this analysis, the ratio of pipe lengths was used as an indicator to ratio the pipe break frequencies. The ratio for MFW was 0.01 (25/2500) and that for main steam piping was 0.025 (50/2000). Therefore, the estimated frequency of a MFW rupture in the vicinity of the CCW doors was 1.0×10^{-5} ($0.01 \times 1.0 \times 10^{-3}$). The estimated frequency of a main steam line break in this area was 5.3×10^{-6} ($0.025 \times 2.1 \times 10^{-4}$). The total HELB frequency in this area due to a MFW line break (HELB-PC) or a main steam line break was estimated to be 1.5×10^{-5}/year.

Probability of CCW pump failure when exposed to harsh environment (CCS-COOL)

As stated in Ref. 1, the CCW pump motors and associated equipment are not qualified for the high temperature/high humidity environment that could occur as a result of a postulated HELB. Operating experience was reviewed to investigate the response of pumps that were not qualified for high humidity to events that imposed those environmental conditions on such pumps. First, approximately 80 LERs that reported water spray, cascade, flood, or high humidity problems affecting pumps were identified using the NRC's Sequence Coding and Search System (SCSS) database. Of these, a sample of approximately 50% was screened, resulting in four LERs being identified for detailed review, since they contained information on pumps impacted by steam environments. The purpose of the review was to identify whether the pumps failed when subjected to a high humidity or temperature environment. If a failure did occur, the nature of the failure was examined to determine the recoverability. Some observations from this review are as follows. In two of the four events that were reviewed in detail (LER Nos. 302/91-003 and 251/90-008), pumps failed when exposed to a steam environment due to moisture intrusion of the motor winding. These did not appear to be recoverable. There was one event where the pumps continuously ran, even when water had collected in the lower motor bearings (LER No. 285/92-031). The fourth event (LER No. 272/90-033) appeared to be a recoverable pump failure. Therefore, during three of the four events, the pumps failed (two non-recoverable failures and one potentially recoverable failure). As a result of this review, it was concluded that there is a high likelihood that the CCW pumps would fail when exposed to a harsh environment (CCS-COOL). This failure probability was assumed to be 1.0 for the following reasons:

- An accurate count of failures and demands could not be used to estimate a failure probability due to biases in reporting failed versus successful operation of pumps exposed to moisture;
- As pump motors age, the likelihood that the motor will develop a crack in the winding insulation increases. The CCW pumps at Cook have been in operation for approximately 25 years.
- Periodic testing of CCW pumps would not reveal any pre-existing cracks in the motor windings.

Reference 5 provides additional bases to support this conclusion.

Potential impact on Unit 1 versus Unit 2 CCW pumps (NSS-CSS-RM)

It was determined that the steam that enters the CCW room during pipe rupture in the pipe chase would most likely fail the CCW pumps supporting Unit 2. However, this event would not be expected to fail the two CCW pumps that support Unit 1 or the spare CCW pump. Reference 5 provides the detailed basis for this conclusion. In summary, this is attributed to a three-hour fire barrier, buoyancy of steam, and the large open spaces connecting to the pipe chase.

As discussed previously, the Unit 2 CCW pumps are separated from the Unit 1 CCW pumps and the spare CCW pump by a three-hour fire barrier, which is ~2.1 m (7 ft) tall. The CCW Pump Room is ~4.3 m (14 ft) tall. The barrier extends from the CCW Pump Room wall to beyond the location of the pumps, ~9.1 m (30 ft) long. There will be more resistance to steam flow through the CCW Pump Room than out of the pipe chase (i.e., into the turbine building). Thus the pressure differential driving the steam flow would favor entering the turbine building instead of toward the CCW Pump Room. The velocity of the steam entering the CCW Pump Room would be low and the natural buoyant forces would cause the steam to rise to the ceiling of the room. Given the low horizontal velocity and considering the protection afforded by the fire wall surrounding the Unit 1 CCW pumps and the spare CCW pump, it was assumed that only the Unit 2 CCW pumps were likely to be exposed to a harsh steam environment (NSS-CSS-RM).

Recovery credit for the spare CCW pump

As discussed above, the spare CCW pump may remain functional in the aftermath of an HELB in the pipe chase. The spare CCW pump can be aligned to support either of the units. Therefore, whether the operators have the capability to align the spare pump in about 1.5 h [prior to reactor coolant pump (RCP) failure due to lack of seal or lubricating oil cooling[16] was investigated. Based on Ref. 14, it was concluded that the actions necessary to swap the pump from Unit 1 to Unit 2 are scheduled to take 8 h, and generally take about 16 h. In the event of an emergency, due to the high priority that would be assigned to this activity, the actions might be completed in 4–5 h. Therefore, it was concluded that no recovery credit could be given for the spare CCW pump to support Unit 2 prior to reactor coolant pump (RCP) seal failure.

Recovery credit for the CVCS cross-tie

If the Unit 2 CCW pumps were lost, seal injection from the charging pumps would be adversely affected. It would be possible to provide cooling to the Unit 2 reactor coolant pump (RCP) seals using a cross-tie from the Unit 1 chemical and volume control system (CVCS).

However, the CVCS cross-tie was not credited in this analysis due to the following uncertainties about its availability:

- *Guidance on re-initiation of seal injection.* The Westinghouse emergency response guidelines caution against re-initiation of seal injection if the RCP seals have heated up. Consistent with this guidance, the licensee's procedure[20] would not reinitiate seal injection if the RCP Seal 1 Outlet Temperature alarms were LIT. Given that the thermal barrier would be lost immediately after the break, and seal injection would be degraded, these alarms might light before the actual RCP seal failure. As a result, even if the CVCS cross-tie were established, the operators might opt to starve the Unit 2 RCP seals.

- *Procedural Guidance.* Reference 20 provides guidance on how to establish the CVCS cross-tie in the event of a loss of CCW. After an HELB, the time at which the procedure on loss of CCW would be entered is unknown. Whether this procedure can be implemented prior to RCP seal outlet temperature alarms activating is unknown. (According to Ref. 16, seal failure would start at about 1 h.)

Material condition of the CVCS cross-tie. Inspection Report 50-315/99-004 (Ref. 19) indicated that small particulate foreign material was found inside the cross-tie header. The exact amount of particulate was unknown and could be insufficient to fail the seal cooling. However, in combination with other factors mentioned above, the presence of particulate represents a new failure mode.

Impact of actuation of fire suppression systems due to steam in the CCW room

There have been operating events in the past in which fire suppression systems have actuated as a result of steam (e.g., LER 281/86-020, Surry feedwater line break event). Therefore, whether the Unit 1 CCW pumps might fail as a result of fire suppression spray actuation was investigated. Based on information provided by the licensee,[15] it was concluded that this was not a credible scenario. The CCW area has fire suppression sprays for the general area, as well as sprays dedicated to suppress fires in the CCW motors. If main steam entered the CCW area, it might actuate the sprays in the general area. However, the pumps are equipped with shields to allow them to continue to operate.

Consequences of CCW pump failure (CCS-PMP-REC)

If the CCW pumps failed due to the postulated steam environment, cooling to the RCP seals would be lost. Even though the RCP seals can also be cooled by seal injection, since the charging pumps require CCW for charging pump seal cooling, the seal injection function would also be lost. With no seal cooling, the Westinghouse type RCP seals would degrade rapidly. The D.C. Cook Nuclear Plant IPE[10] assumes that the RCP seals will fail with a probability of 1.0 if seal cooling is unavailable for 1-h. This assumption is conservative since all eight RCPs at Units 1 and 2 have newer high temperature seals. Based on the RCP seal failure models suggested by NUREG/CR-4550 (Ref. 16) for new high temperature seals, the seal failure probability (CCS-PMP-REC) when seal cooling is lost for an extended period is 0.19.

If an RCP seal LOCA were to occur, according to the modeling discussed in the Cook IPE, [10] and based on actual RCP seal LOCA events, high-pressure injection (high pressure, low volume) is needed to mitigate the accident. However, all four high-pressure injection (HPI) pumps at the D.C. Cook plant are cooled by CCW, so a loss of CCW could lead to a loss of HPI. According to the D.C. Cook UFSAR,[3] all HPI pumps at Cook are highly dependent on CCW. The seal and lube oil heat exchangers of the two safety injection pumps are cooled by CCW. In addition, the pump gear, lube oil, and seal exchangers of the centrifugal charging pumps are also cooled by CCW. Even if the HPI pumps could inject for a short duration to terminate the RCP seal LOCA and stabilize the reactor coolant system (RCS), the RCS must be cooled down and depressurized. With CCW unavailable, the operator would be expected to trip the RCPs. Therefore, forced circulation would be unavailable. With only natural circulation in the RCS, there is no basis to conclude that the RCS would be stabilized before the HPI pump seals would be damaged due to loss of cooling. Therefore, the probability of failure of all HPI pumps, given CCW unavailable, was assumed to be 1.0.

B.4.5 Analysis Results

Figure B.4.1 shows the accident sequence that leads to core damage. This sequence consists of the following:

- An HELB occurs in the high energy pipe chase in the vicinity of one of the three doors leading to the CCW Pump Room ($f = 1.5 \times 10^{-5}$/year).
- Access doors fail to prevent steam from entering CCW pump room (p = 0.0 for Unit 1, 1.0 for Unit 2).

- Failure of the running and standby CCW pumps and the spare CCW pump due to high humidity and high temperature environment (p = 1.0).

- Failure of RCP seals given failure to recover any CCW pump and restore seal cooling to the RCPs (p = 0.19).

- Failure to recover HPI pumps prior to core uncovery (p = 1.0).

Since failure of the CCW pumps would cause an RCP seal LOCA and would also fail the mitigating capability (i.e., the HPI pumps), a steam line break or a MFW line break in the vicinity of these doors could lead to core damage. Thus the conditional core damage frequency (CCDF - conditional frequency of subsequent core damage given the failures observed during an operational event) associated with this condition is 3.0×10^{-6}.

B.4.6 References

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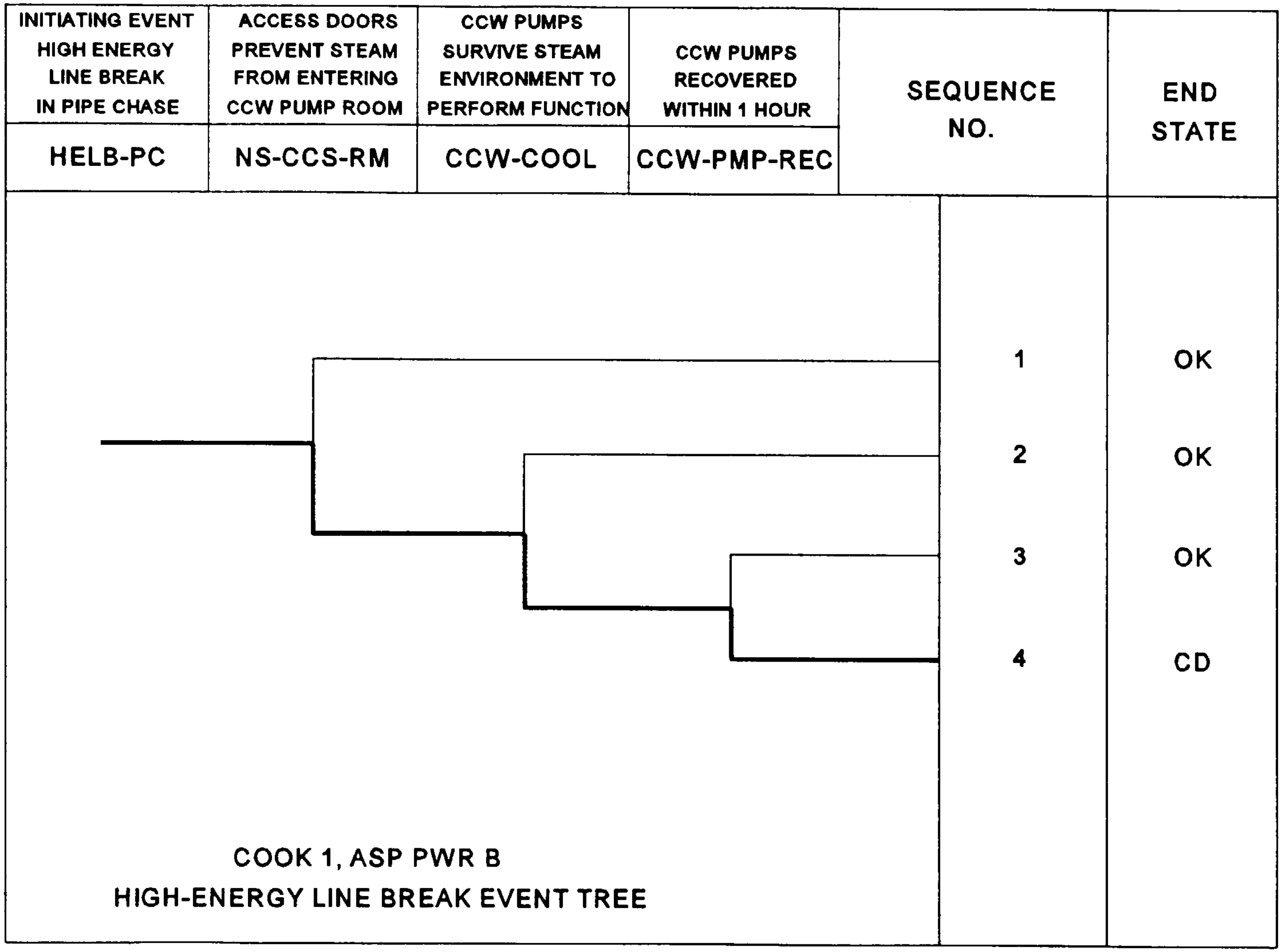

Fig. B.4.1 Dominant core damage sequence for LER No. 316/98-005. (CCW is component cooling water)

B.5 LER No. 346/98-006

Event Description: A tornado touchdown causes a complete (weather-related) loss of offsite power

Date of Event: June 24, 1998

Plant: Davis-Besse 1

B.5.1 Event Summary

The Davis-Besse Plant was in Mode 1 at 99% power at ~2040 on June 24, 1998, when a severe thunderstorm cell moved into the area. Several minutes later, a tornado touched down either near or in the switchyard, damaging switchyard equipment and causing a complete loss of offsite power (LOOP). Before the touchdown of the tornado, the senior reactor operator (SRO) instructed the operators to start the EDGs from the control room because of the severe weather conditions. Although EDG 2 started successfully, EDG 1 failed to start. Operators then attempted to start EDG 1 locally; EDG 1 started successfully. Several minutes later, a tornado touched down in or near the switchyard, causing a complete LOOP. The LOOP caused the turbine control valves to close in response to a load rejection by the main generator. The reactor protection system (RPS) initiated a reactor trip on high reactor coolant system (RCS) pressure. At 2118 on June 24, the licensee declared an Alert as prescribed by the plant's emergency procedures. On June 25, 1998, at ~2330, following the restoration of the Ohio Edison offsite line, the EDGs were shut down. The Alert was subsequently downgraded to an Unusual Event at 0200 on June 26, 1998, because personnel had restored one offsite power source. The Unusual Event was terminated at 1405 on June 26, after personnel had restored a second offsite power source.[1,2] The conditional core damage probability (CCDP) for this event is 5.6×10^{-4}.

B.5.2 Event Description

At 1946 on June 24, 1998, with the Davis-Besse Plant operating at ~99% power, a severe thunderstorm warning was issued for Ottawa County, Ohio, by the National Weather Service. A few minutes later, this was upgraded to a tornado warning when a tornado was spotted ~17.7 km (11 mi) northwest of Port Clinton, Ohio. At 2040, a lightning strike caused switchyard air circuit breaker (ACB) 34561 to open. In addition, the lightning strike caused switchyard ACB 34562 to cycle three times; this ACB eventually stayed open. The senior reactor operator (SRO) instructed the operators to start the EDGs from the control room because of the severe weather conditions. Although EDG 2 started successfully, EDG 1 failed to start. Operators then attempted to start EDG 1 locally; EDG 1 started successfully. Several minutes later, a tornado touched down in or near the switchyard, causing a complete LOOP. Simultaneously, the plant computer system failed because of the loss of power to a 120V-ac electrical distribution panel (panel YAU).

After the LOOP and the resulting reactor trip, all control rods inserted. The EDGs, which were already running, automatically connected to their respective emergency buses. Because the EDGs were running, the station blackout diesel generator (SBODG) was not required. The two turbine-driven auxiliary feedwater (TDAFW) pumps started successfully. Although the TDAFW pumps operated successfully, the operators started the motor-driven auxiliary feedwater pump and used that pump to supply feedwater to the steam generators. The LOOP had caused a loss of power to the reactor coolant pumps (RCPs); however, operators established natural circulation cooling and began circulating the reactor coolant. The transient that followed the LOOP and the subsequent reactor trip caused the secondary system pressure to rise. As a result, the main steam safety valves (MSSVs) lifted to relieve pressure and the operators opened the atmospheric relief valves to control steam pressure. One MSSV actuated below its set point and failed to reseat fully. However, as the header pressure decreased, that MSSV fully reseated. With all critical safety functions successful, at 2353, the operators commenced a plant cooldown.

With the offsite power sources still unavailable on June 25, the EDGs continued supplying power to the emergency buses. That day, the operator noted that the EDG room temperatures were increasing with time. At 0817, the doors leading to the outside from both EDG rooms were opened to stop the temperature rise. The EDG room ventilating system is sized to maintain each "operating" EDG room at 48.9°C (120°F) assuming outside air at 35°C (95°F). In spite of the opened door, the temperature in the EDG 1 room continued to increase because the recirculation damper to the room had failed in the open position. The open damper allowed hot outside air to enter the EDG room and eventually caused the room temperature to increase beyond its design value. To arrest the temperature rise in this EDG room, the operators mechanically disconnected and closed the recirculation damper. In addition, personnel placed two portable fans in the room to enhance air circulation. In spite of these compensatory actions, at 1313 the EDG 1 room temperature rose to 50.0°C (122°F). Finally, by using additional portable fans and blocking open the door between the EDG 1 room and the plant, the licensee successfully arrested the temperature rise. By 1640, the room temperature stabilized at 45.6°C (114°F). Although EDG 1 was declared inoperable per plant procedures because of the high EDG room temperature, it was in fact available to perform its safety function—EDG 1 provided essential electric power during this event. The recirculation damper in EDG 2 room had also failed in a slightly open position. An operator mechanically disconnected this damper and put the damper in the fully closed position. Unlike the situation with the EDG 1 room, this action, in conjunction with opening the EDG 2 room door to the outside, was sufficient to maintain the EDG 2 room temperature below 45.0°C (113°F).

Besides the malfunctions experienced in controlling the room temperatures, personnel encountered other complications while transferring electrical power from the EDGs to the offsite power sources. At ~2100 on June 25, when operators attempted to transfer the power supply to buses C1/C2 from bus B (bus B is powered from the offsite source), circuit breaker ABDC1 failed to close. The transfer was performed using a dead bus. While personnel were transferring the power supply to buses D1/D2 from the EDGs to the offsite source, they received EDG 2 fault and frequency alarms. The root cause of the malfunction that caused the alarms on EDG 2 was a failed open contact that affected the EDG's governor. If the EDG had to be stopped and restarted during the LOOP, this failure would be easily recoverable.

B.5.3 Additional Event-Related Information

During a LOOP, the EDGs provide power to the emergency buses. If both EDGs were to fail, the plant's SBODG would automatically start and load onto one of the emergency buses. When the SBODG successfully starts, it supplies its own auxiliaries. When the SBODG is in standby, the nonessential D2 bus supplies power to its auxiliaries. A 125V-dc battery system is one of the SBODG auxiliaries. These batteries have sufficient capacity to maintain dc control power and diesel-generator starting and loading ability. If bus D2 is not powered and the SBODG is not running, the SBODG batteries will deplete in 2.0 h. SBODG breaker AD 213 is normally closed and receives its control power from train 2 of the dc distribution system. The SBODG fuel oil tank is separate from the EDGs' fuel oil tanks. This tank has enough fuel capacity for an 8-h run of the SBODG at the rated load.

The SBODG and its auxiliaries (except the engine radiator) are inside their own structure, which is in a different part of the site from the EDGs. The structure was designed and built to meet the Ohio State Basic Building Code. Meeting this code assures protection for the SBODG from the most likely weather-related events that could cause a LOOP, such as rain, ice, or moderate to heavy straight winds (e.g., during a thunderstorm). However, it does not afford protection against damage from the effects of more severe weather conditions (e.g., tornado-caused missiles). Although the SBODG engine radiator is located outside, it has been designed to withstand the same types of weather conditions as the SBODG enclosure (i.e., it is also vulnerable to tornado-generated missiles). The electrical cabling associated with the SBODG is routed through a buried duct bank.

B.5.4 Modeling Assumptions

This event was analyzed as an extremely severe weather-related LOOP. The Integrated Reliability and Risk Analysis System (IRRAS)-based models and analysis tools used by the ASP Program for precursor quantification automatically revised the probabilities for certain basic events and nonrecovery probabilities. The revised probabilities more accurately reflect the effect that extremely severe weather would have on the parameters used in calculating the likelihood of recovering offsite power, the probability of a reactor coolant pump (RCP) seal loss-of-coolant accident (LOCA), the likelihood of battery depletion, and the probability of demanding the EDGs to start and run. Each revised probability is discussed below. Not all equipment malfunctions impacted the core damage probability (CDP) associated with this event. Justification for not revising the base probability of equipment failure or operator action is also discussed below.

Equipment abnormalities and operator actions that impact the CDP

Duration of the LOOP event

The LOOP event occurred at 2047 on June 24, 1998. The first offsite power source was restored at 1926 on June 25, 1998. In consideration of the above, this analysis used a 24-h duration for this LOOP event. The offsite power nonrecovery probabilities for the following basic events in the models were set to TRUE (i.e., probability of occurrence is 1.0) for this initiating event to reflect the anticipated longer times that would be required to recover offsite power: (1) OEP-XHE-NOREC-ST (failure to recover offsite power in the short term), (2) OEP-XHE-NOREC-2H (failure to recover offsite power within 2 h), (3) OEP-XHE-NOREC-6H (failure to recover offsite power within 6 h), and (4) OEP-XHE-NOREC-SL (failure to recover offsite power before RCP seal failure).

Failure probabilities of the EDGs

The IRRAS-based models and analysis tools used by the ASP Program for precursor quantification automatically revised the probabilities for certain basic events and nonrecovery probabilities. The revised probabilities more accurately reflect the effect that extremely severe weather would have on the parameters used in calculating the likelihood of recovering offsite power, the probability of a reactor coolant pump seal LOCA, and the likelihood of battery depletion. The basic event probabilities that were revised include the probability that the EDGs (basic events EPS-DGN-FC-DGA and -DGB) and the SBODG (basic event EPS-DGN-FC-SBO) will fail to start and run because of the extremely severe weather (increased from the nominal value of 3.6×10^{-2} to 7.8×10^{-2}).

When the operators attempted to start the EDGs manually from the control room as a result of the severe weather warnings at 2044, EDG 1 failed to start. However, in the modeling of the event in the ASP analysis, the probability of random failure of EDG 1 (basic event EPS-DGN-FC-DGA) was neither set to "TRUE" nor increased from the probability associated with a severe weather-related LOOP. The reasons for not changing the random failure probability are as follows:

- Operators started EDG 1 before the LOOP occurred. Although the operators originally had failed to start EDG 1 using the hand switch in the control room, within 2 min operators had successfully started it manually.
- Subsequent investigations concluded that the contact for the hand switch in the control room was defective; despite the bad contacts, if EDG 1 had received an automatic signal, it would have started successfully.

Although both EDGs were running before the LOOP occurred, the EDG failure-to-start probability contribution was not removed from the overall EDG failure probability; both EDGs were started only a few minutes before the LOOP. EDG 1 started ~1 min before the LOOP, and EDG 2 started ~3 min before the LOOP. If the EDGs had been running for a significant amount of time before the LOOP occurred (e.g., for several hours), the EDG failure-to-start probability contribution would have been removed from the overall EDG failure probability.

SBODG vulnerability to tornadoes

Unlike the EDGs, the SBODG is not protected from tornado-generated missiles. Reasonable protection from high wind and tornado effects is provided to the SBODG as follows: First, the cabling associated with the SBODG is routed through a buried duct bank. Therefore, these cables are protected from tornado effects. Second, according to the final safety analysis report (FSAR),[3] only the engine radiator of the SBODG is outside the building. However, the radiator has been designed to withstand most types of outdoor conditions, except effects of the most severe weather (e.g., tornado-generated missiles). Finally, the SBODG is enclosed in a structure that meets the Ohio building code. Although this structure provides protection against falling light debris, the building does not afford protection against tornado-generated missiles. Therefore, unlike the EDGs, the SBODG is vulnerable to missiles. References 1 and 2 documents the damage incurred at the Davis-Besse site because of this tornado. While there was damage to several onsite and offsite systems (e.g., offsite power, the telephone system, meteorological tower instruments, and the roof of the turbine building), there was no evidence of damage caused by heavy missiles anywhere on the site, and no heavy missiles were observed during the storm. Most of the damage incurred by equipment and buildings because of the tornado was caused by high winds and accompanying heavy rain. That is, during this tornado [classified by the National Weather Service as

"F2" due to wind speeds between 182–253 km/h (113–157 mi/h)], the small target area of the SBODG was not threatened by heavy missiles. The SBODG building is at the southern edge of the site; it is not near the turbine building or the switchyard. Also, the SBODG building is not on a straight line path between these two site structures. Most of the physical damage to structures because of the tornado that struck the site occurred at the switchyard and at the turbine building. Based on these considerations, this analysis assumed that the likelihood of failure of the SBODG as a result of missiles, given that the tornado occurred, was negligible compared to the random SBODG failure probability of 7.8×10^{-2}. Hence, the probability of SBODG failing to start or run (EPS-DGN-FC-SBO) was not revised further from the probability used to reflect the effects of the severe weather conditions based on the SBODG providing power to its own auxiliaries and its reliance on nonessential bus D2. A new basic event was added to the Davis-Besse model, ACP-XHE-XE-ALT, to represent the probability that the operator fails to start the SBODG and to align it to supply power to bus D2 (probability = 1.0×10^{-2}).

Common-cause failure considerations between the SBODG and the EDGs

The SBODG provides diversity against common-cause failure (CCF) of the EDGs. The CCF coupling mechanisms between the SBODG and the EDGs are few. For example, the two EDGs and the SBODG are of different design. While the EDGs are cooled by service water, the SBODG is air-cooled. Unlike the EDGs, which are located in adjacent structures, the SBODG has its own structure. The SBODG does not share auxiliaries, such as fuel tanks, with the EDGs. The test and maintenance practices on the EDGs are different from those for the SBODG. Therefore, the IRRAS-based model for Davis-Besse was modified to capture the distinction between the CCF considerations for the EDGs and those involving the SBODG. The failure probability for the basic event, EPS-DGN-CF-ALL, which represents the CCF probability for the two EDGs and the SBODG, was reduced to 3.6×10^{-5} to reflect the weak coupling among the three EDGs. A new basic event, EPS-DGN-CF-AB, was added to account for the CCF susceptibilities between the two EDGs. The probability for this basic event was estimated using Ref. 5 to figure out the alpha factor for two-out-of-two EDG failures. This resulted in an EDG CCF probability of 3.0×10^{-3}. The Nuclear Regulatory Commission's (NRC's) CCF database[5] was reviewed to identify events that could fail two EDGs and the SBODG. Four events were identified. During two of these events, the cold weather common to the site caused the failures. During the other two events, biofouling of the EDGs' fuel oil caused the failures. Based on these four failures, the alpha factor used in the CCF calculations for three-out-of-three EDG failures was estimated to be 4.6×10^{-4}.

Equipment abnormalities that do not impact the CDP

Switchyard ACB failures

During the storm, ACB 34561 opened. Subsequently, ACB 34562 cycled open three times and eventually stayed open. These two breakers connect offsite power lines to the switchyard at the Davis-Besse site. The opening of these breakers along with damage to the switchyard, led to the LOOP. Therefore, the impact of the condition of these breakers was implicitly captured in the CCDP assessment.

Non-1E power for SBODG auxiliaries

When the SBODG successfully starts, it supplies power to its own auxiliaries. However, if the SBODG is in standby, nonessential bus D2 supplies power to the SBODG auxiliaries. If bus D2 were not powered, then some SBODG auxiliaries (e.g., SBODG battery) would degrade. Without recharging from either the SBODG or bus D2, the SBODG batteries will deplete in 2.0 h. Because of this and the need to power the motor-driven feedwater pump (in the auxiliary feedwater mode), the emergency procedure gives high priority to powering bus D2 as soon as possible. During the event, the operators restored power to bus D2 from EDG 2 within 15 min. Hence, the probability of the operators failing to restore power to nonessential bus D2 (ACP-XHE-BUS-D2) was not revised from its base probability of 1.0×10^{-2}.

Limited capacity of SBODG fuel oil tank

The SBODG fuel oil tank is separate from the EDGs' fuel oil tanks. It has enough capacity for an 8-h run at the rated load. Although detailed procedures exist for routine refilling of the tank, no procedures exist for checking the fuel oil tank level during a LOOP. Regardless, in comparison to the random failure of the SBODG (7.8×10^{-2}), the probability of failing to refill the SBODG fuel tank is low. Therefore, that failure probability is not explicitly modeled in this analysis. Hence, the probability of SBODG failing to start or run (EPS-DGN-FC-SBO) was not revised further from the probability used to reflect the effects of the severe weather conditions based on the limited capacity of the fuel oil tank.

Loss of power to the 120V-ac electrical distribution panel YAU

During cleanup activities, personnel discovered that the LOOP, in combination with the loss of electrical distribution panel YAU, resulted in the condensate polisher's isolation valves and the condensate recirculation valve failing open. This failure caused the release of condensate system resin to the hotwell, that in turn, elevated the sulfate level in the secondary-side water. Other consequences of the loss of panel YAU were speculated to be the loss of input signals to the safety parameter display system (SPDS). Although the loss of the SPDS results in a loss of critical information on RCS parameters in a graphical display format, the operators have access to this information via other means. Therefore, loss of this bus was assumed to have no impact on CDP.

Failure of a main steam safety valve to reseat

When the reactor tripped because of the LOOP, this caused a pressure transient on the secondary side. One main steam safety valve (MSSV) lifted below its set point and did not fully reseat. However, when the steam pressure dropped, this MSSV fully reseated. The impact of this degradation (deviation of the actual lift pressure from the set point) was assumed to be negligible because the valve did reclose at a lower pressure.

Failure of the EDG 2 electronic governor

After recovering offsite power, while operators began transferring power to busses D1/D2 from EDG 2 to offsite power, the EDG 2 electronic governor failed. This failure was attributed to a contact pair failing to open. This condition could have influenced the CDP if the EDG had to be stopped and restarted during the LOOP. The licensee's procedures do not specify the stopping and the restarting of the EDG during a LOOP. Further, the failure was easily recoverable. Therefore, this failure was assumed to have no impact on the CDP.

Failure of the EDG 1 room ventilation recirculation damper

Because of the continued heating up of the EDG 1 room, the operators determined that the ventilation recirculation damper had failed open. This analysis did not increase the EDG "failure to run" probability in spite of this degradation and assumed that the impact on CDP was negligible based on the following justification:

- As illustrated by the actions pursued during this event, the operators had the capability to detect and take compensatory measures (opening doors and installing fans) to arrest the temperature rise.
- The maximum temperature reached was 51.7°C (125°F). Per plant procedures, this resulted in EDG 1 being declared inoperable, because it exceeded the 48.9°C (120°F) design parameter for the EDG ventilation system. Subsequent analysis performed by the licensee determined that the most limiting components for temperature in the rooms were the EDG differential relays and that the limiting temperature for these relays was 55.0°C (131°F).
- Although personnel declared EDG 1 inoperable per plant procedures, it was available to perform its safety function; in fact, it continued to provide essential electric power during the event.

Degraded EDG 2 ventilation recirculation damper

The operators determined that the recirculation damper in the EDG 2 ventilation system had failed slightly open. However, the impact on the CDP attributed to this condition was assumed to be negligible due to the following:

- As illustrated by actions taken during this event, the operators had the capability to detect and take compensatory measures (opening doors and installing fans) to arrest the temperature rise.
- The maximum temperature reached was 45.0°C (113°F).

Failure of circuit breaker ABDC1

After the initial recovery of offsite power, while personnel were transferring the supply for bus C1/C2 from EDG 1 to offsite power, breaker ABDC1 failed to close. Operators had to accomplish a dead bus transfer shortly thereafter. The condition that caused the breaker failure affected the recovery of offsite power. However, it did not affect the capability to establish power from EDG 1 to the emergency bus. Further, it did not affect the capability of the EDG to continue to run. As illustrated, operators easily compensated for the failure of the breaker by providing offsite power to the emergency bus via an alternate path. Because this failure had no adverse impact, the failure was not explicitly modeled in the CCDP calculations.

Automatic reset of the CREVS train 1 from water- to air-cooled mode

The CREVS train operated properly in the air-cooled mode until operators reset the system to the water-cooled mode. Therefore, there was no impact on the CDP.

Loss of power to emergency notification system equipment and loss of all wind speed and direction sensors

The loss of power to some equipment, such as sirens, and wind damage to the wind speed and direction sensors in the meteorological tower had some impact on emergency management and risk to the public. However, there was no impact on the CDP.

Water intrusion into the turbine building cable trays and MCC E5

Rainfall that entered the turbine building through the storm-induced hole in the roof caused water intrusion in the cable trays. The impact of this on the CDP was assumed to be negligible because the cables that got wet were not safety-related, and water impinging on the cable jackets did not impact their functionality. The water intrusion in motor-control center (MCC) E5 caused damage (i.e., the ground faulting of a circuit breaker). However, MCC E5 supplies nonessential lighting only. Therefore, this failure had no impact on the CDP.

B.5.5 Analysis Results

The CCDP estimated for this event is 5.6×10^{-4}. All of the dominant sequences for this event involve station blackout (SBO) sequences coincident with the depletion of the batteries (sequences 18-02 and 18-11 in Fig. B.5.2), the failure of the RCP seals because offsite power was not recovered in a timely manner (sequences 18-09 and 18-18), or a PORV sticking open with the failure to recover offsite power in the short term (sequence 18-20). The dominant sequence, highlighted on the event trees in Figs. B.5.1 and B.5.2, involves a SBO sequence, LOOP Sequence 18-02:

- a LOOP,
- a successful reactor trip,
- a failure of emergency ac power,
- a successful initiation of auxiliary feedwater,
- no challenge to the power-operated relief valves (PORVs) or the safety valves,
- sufficient cooling so that the RCP seals do not fail, and
- a failure to recover offsite power before the batteries are depleted, which leads to core damage.

The next most dominant sequences, LOOP Sequences 18-11 and 18-09 in Fig. B.5.1 and Fig. B.5.2, contribute approximately 32% and 7%, respectively, to the CCDP. LOOP Sequence 18-11 involves an SBO, the PORVs open and reclose successfully, the RCP seals do not fail, and failure to recover offsite power before battery depletion, resulting in core damage. LOOP Sequence 18-09 involves an SBO, failure to recover offsite power in the short-term, and failure to recover offsite power before a seal LOCA occurs, leading to core damage.

All dominant cut sets include the failure of the EDGs and the SBODG. The duration of the LOOP event is a significant contribution.

Definitions and probabilities for selected basic events are shown in Table B.5.1. The conditional probabilities associated with the highest probability sequences are shown in Table B.5.2. Table B.5.3 lists the sequence logic associated with the sequences listed in Table B.5.2. Table B.5.4 describes the system names associated with the dominant sequences. Minimal cut sets associated with the dominant sequences are shown in Table B.5.5.

B.5.6 References

1. LER 346/98-006, "Tornado Damage to Switchyard Causing Loss of Offsite Power," August 21, 1998.

2. NRC Team Inspection Report 50-346/98012 (DRP), August 14, 1998.

3. *Davis-Besse Unit 1, Final Safety Analysis Report.*

4. Davis-Besse Unit 1, *Individual Plant Examination*, February 26, 1993.

5. Marshall, Rasmuson, and Mosleh, *Common-Cause Failure Parameter Estimations*, USNRC Report NUREG/CR-5497, October 1998.

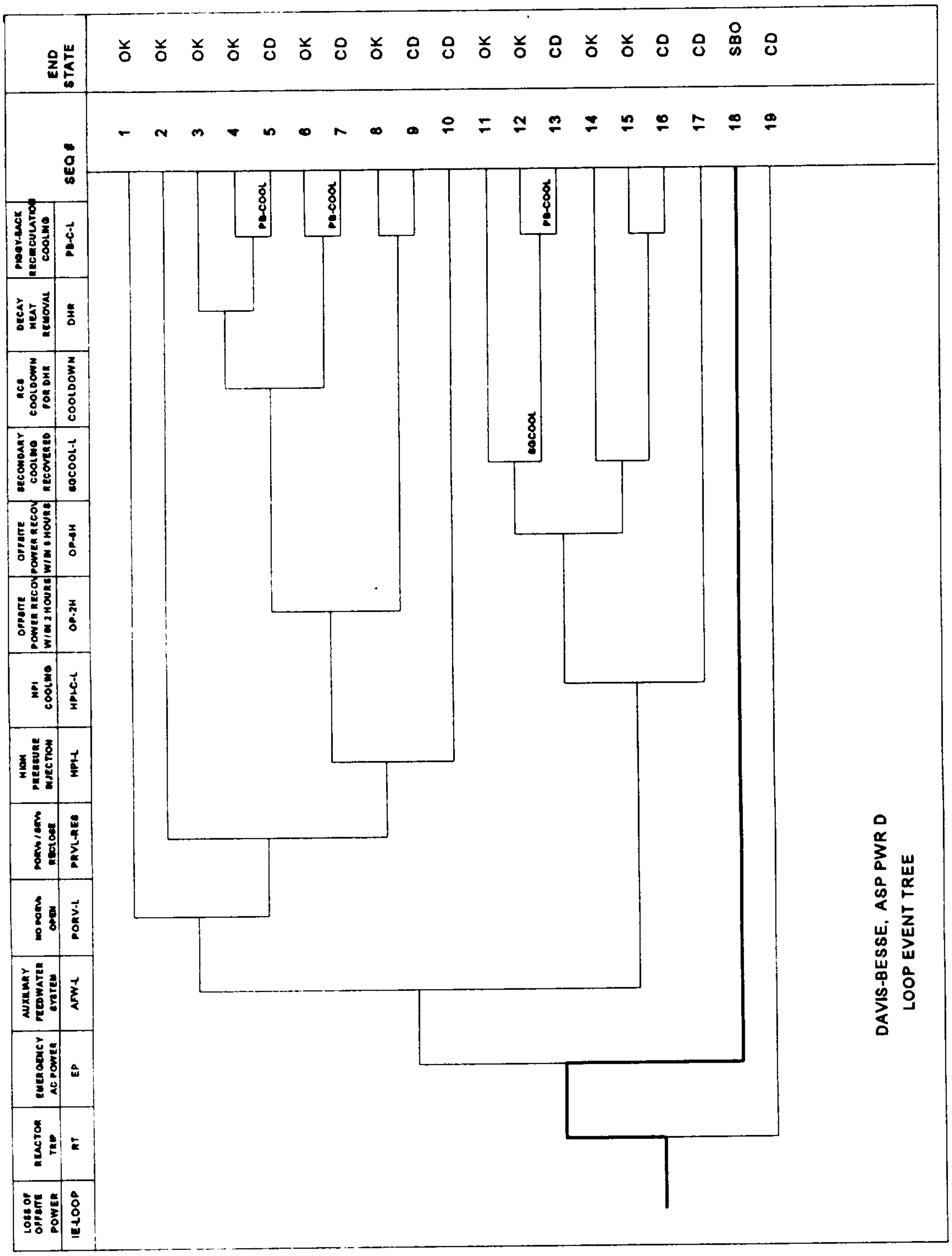

Fig. B.5.1 Dominant core damage sequence for LER 346/98-006.

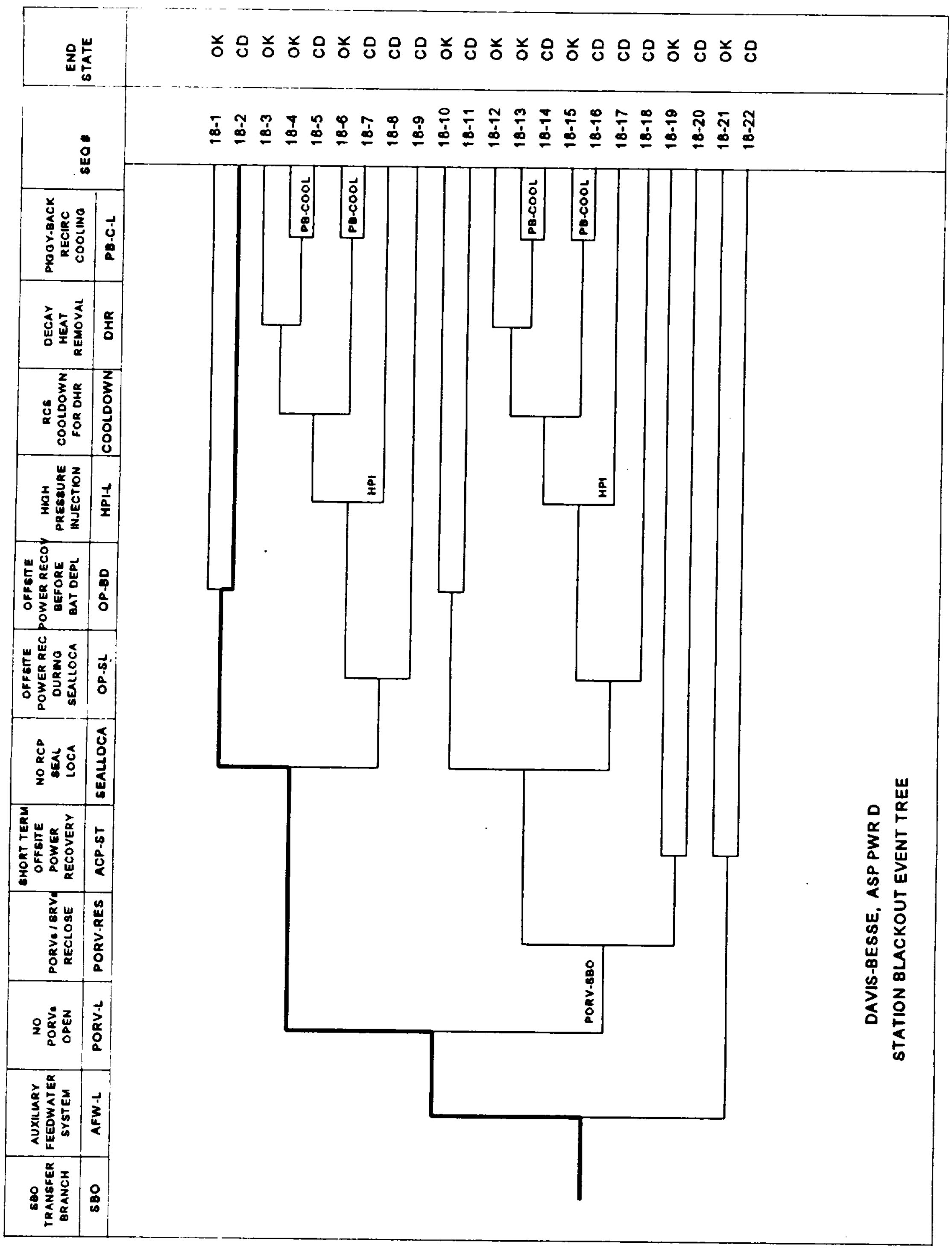

Fig. B.5.2 Dominant core damage sequence for LER 346/98-006.

Table B.5.1. Definitions and Probabilities for Selected Basic Events for LER No. 346/98-006

Event name	Description	Base probability	Current probability	Type	Modified for this event
IE-LOOP	Initiating Event–LOOP	1.6 E-005	1.0 E+000	TRUE	Yes
IE-SGTR	Initiating Event–Steam Generator Tube Rupture	1.6 E-006	0.0 E+000		Yes
IE-SLOCA	Initiating Event–Small Loss-of-Coolant Accident (SLOCA)	2.3 E-006	0.0 E+000		Yes
ACP-XHE-BUS-D2	Operator Fails to Power Nonessential Bus D2	1.0 E-002	1.0 E-002	NEW	No
ACP-XHE-XE-ALT	Operator Fails to Align the Station Blackout Diesel Generator (SBODG)	1.0 E-002	1.0 E-002	NEW	No
EPS-DGN-CF-AB	Common-Cause Failure (CCF) of the Emergency Diesel Generators (EDGs)	3.0 E-003	3.0 E-003	NEW	No
EPS-DGN-CF-ALL	CCF of EDGs and SBODG	3.6 E-005	3.6 E-005	NEW	No
EPS-DGN-FC-DGA	EDG 1 Fails to Start and Run	3.6 E-002	7.8 E-002	Extremely severe weather LOOP	Yes
EPS-DGN-FC-DGB	EDG 2 Fails to Start and Run	3.6 E-002	7.8 E-002	Extremely severe weather LOOP	Yes
EPS-DGN-FC-SBO	SBODG Fails to Start and Run	3.6 E-002	7.8 E-002	Extremely severe weather LOOP	Yes
LOOP-18-02-NREC	LOOP Sequence 18-02 Nonrecovery Probability – Failure to Recover Electric Power (EP)	8.0 E-001	8.0 E-001		No
LOOP-18-09-NREC	LOOP Sequence 18-09 Nonrecovery Probability – Failure to Recover EP	8.0 E-001	8.0 E-001		No

Table B.5.1. Definitions and Probabilities for Selected Basic Events for LER No. 346/98-006 (Continued)

Event name	Description	Base probability	Current probability	Type	Modified for this event
LOOP-18-11-NREC	LOOP Sequence 18-11 Nonrecovery Probability – Failure to Recover EP	8.0 E-001	8.0 E-001		No
LOOP-18-18-NREC	LOOP Sequence 18-18 Nonrecovery Probability – Failure to Recover EP	8.0 E-001	8.0 E-001		No
LOOP-18-20-NREC	LOOP Sequence 18-20 Nonrecovery Probability – Failure to Recover EP	8.0 E-001	8.0 E-001		No
OEP-XHE-NOREC-2H	Operator Fails to Recover Offsite Power Within 2 h	6.4 E-002	1.0 E+000	TRUE	Yes
OEP-XHE-NOREC-6H	Operator Fails to Recover Offsite Power Within 6 h	3.7 E-002	1.0 E+000	TRUE	Yes
OEP-XHE-NOREC-BD	Operator Fails to Recover Offsite Power Before Battery Depletion	2.0 E-002	7.1 E-001	Extremely severe weather LOOP	Yes
OEP-XHE-NOREC-SL	Operator Fails to Recover Offsite Power Before RCP Seals Fail	7.5 E-001	1.0 E+000	TRUE	Yes
OEP-XHE-NOREC-ST	Operator Fails to Recover Electric Power in Short Term	2.4 E-001	1.0 E+000	TRUE	Yes
PPR-SRV-CO-SBO	PORV/SRVs Open During Station Blackout	3.7 E-001	3.7 E-001		No
PPR-SRV-OO-PORV	PORV Fails to Reclose after Opening	3.0 E-002	3.0 E-002		No
RCS-MDP-LK-SEALS	RCP Seals Fail Without Cooling and Injection	9.3 E-003	8.3 E-002	Extremely severe weather LOOP	Yes

Table B.5.2. Sequence Conditional Probabilities for LER No. 346/98-006

Event tree name	Sequence number	Conditional core damage probability (CCDP)	Percent contribution
LOOP	18-02	3.0 E-004	53.6
LOOP	18-11	1.8 E-004	32.1
LOOP	18-09	3.9 E-005	7.0
LOOP	18-18	2.3 E-005	4.1
LOOP	18-20	8.2 E-006	1.5
Total (all sequences)		**5.6 E-004**	

Table B.5.3. Sequence Logic for Dominant Sequences for LER No. 346/98-006

Event tree name	Sequence number	Logic
LOOP	18-02	/RT-L, EP, /AFW-L, /PORV-SBO, /SEALLOCA, OP-BD
LOOP	18-11	/RT-L, EP, /AFW-L, PORV-SBO, /PRVL-RES, /SEALLOCA, OP-BD
LOOP	18-09	/RT-L, EP, /AFW-L, /PORV-SBO, SEALLOCA, OP-SL
LOOP	18-18	/RT-L, EP, /AFW-L, PORV-SBO, /PRVL-RES, SEALLOCA, OP-SL
LOOP	18-20	/RT-L, EP, /AFW-L, PORV-SBO, PRVL-RES, ACP-ST

Table B.5.4. System Names for LER No. 346/98-006

System name	Logic
ACP-ST	Offsite Power Recovery in Short Term
AFW-L	No or Insufficient EFW Flow During a LOOP
EP	Emergency Power Fails
OP-BD	Operator Fails to Recover Offsite Power Before Battery Depletion
OP-SL	Operator Fails to Recover Offsite Power Before a Seal LOCA Occurs
PORV-SBO	PORVs/Safety Relief Valves Open During an SBO
PRVL-RES	PORVs, Block Valves, and SRVs Fail to Reseat
RT-L	Reactor Fails to Trip During a LOOP
SEALLOCA	RCP Seals Fail During a LOOP

Table B.5. 5. Conditional Cut Sets for Higher Probability Sequences for LER No. 346/98-006

Cut set number	Percent contribution	CCDP[a]	Cut sets[b]
LOOP Sequence 18-02		3.0 E-004	
1	51.3	1.6 E-004	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, EPS-DGN-FC-SBO, LOOP-18-02-NREC, /PPR-SRV-CO-SBO, /RCS-MDP-LK-SEALS, OEP-XHE-NOREC-BD
2	25.0	7.6 E-005	EPS-DGN-CF-AB, EPS-DGN-FC-SBO, LOOP-18-02-NREC, /PPR-SRV-CO-SBO, /RCS-MDP-LK-SEALS, OEP-XHE-NOREC-BD
3	6.6	2.0 E-005	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, ACP-XHE-BUS-D2, LOOP-18-02-NREC, /PPR-SRV-CO-SBO, /RCS-MDP-LK-SEALS, OEP-XHE-NOREC-BD
4	6.6	2.0 E-005	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, ACP-XHE-XE-ALT, LOOP-18-02-NREC, /PPR-SRV-CO-SBO, /RCS-MDP-LK-SEALS, OEP-XHE-NOREC-BD
5	3.9	1.2 E-005	EPS-DGN-CF-ALL, LOOP-18-02-NREC, /PPR-SRV-CO-SBO, /RCS-MDP-LK-SEALS, OEP-XHE-NOREC-BD
6	3.2	9.7 E-006	EPS-DGN-CF-AB, ACP-XHE-XE-ALT, LOOP-18-02-NREC, /PPR-SRV-CO-SBO, /RCS-MDP-LK-SEALS, OEP-XHE-NOREC-BD
7	3.2	9.7 E-006	EPS-DGN-CF-AB, ACP-XHE-BUS-D2, LOOP-18-02-NREC, /PPR-SRV-CO-SBO, /RCS-MDP-LK-SEALS, OEP-XHE-NOREC-BD
LOOP Sequence 18-11		1.8 E-004	
1	51.3	9.2 E-005	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, EPS-DGN-FC-SBO, LOOP-18-11-NREC, PPR-SRV-CO-SBO, /RCS-MDP-LK-SEALS, OEP-XHE-NOREC-BD
2	25.0	4.5 E-005	EPS-DGN-CF-AB, EPS-DGN-FC-SBO, LOOP-18-11-NREC, PPR-SRV-CO-SBO, /RCS-MDP-LK-SEALS, OEP-XHE-NOREC-BD
3	6.6	1.2 E-005	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, ACP-XHE-BUS-D2, LOOP-18-11-NREC, PPR-SRV-CO-SBO, /RCS-MDP-LK-SEALS, OEP-XHE-NOREC-BD
4	6.6	1.2 E-005	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, ACP-XHE-XE-ALT, LOOP-18-11-NREC, PPR-SRV-CO-SBO, /RCS-MDP-LK-SEALS, OEP-XHE-NOREC-BD
5	3.9	6.9 E-006	EPS-DGN-CF-ALL, LOOP-18-11-NREC, PPR-SRV-CO-SBO, /RCS-MDP-LK-SEALS, OEP-XHE-NOREC-BD

Table B.5.5. Conditional Cut Sets for Higher Probability Sequences for LER No. 346/98-006 (Continued)

Cut set number	Percent contribution	CCDP[a]	Cut sets[b]
6	3.2	5.7 E-006	EPS-DGN-CF-AB, ACP-XHE-XE-ALT, LOOP-18-11-NREC, PPR-SRV-CO-SBO, /RCS-MDP-LK-SEALS, OEP-XHE-NOREC-BD
7	3.2	5.7 E-006	EPS-DGN-CF-AB, ACP-XHE-BUS-D2, LOOP-18-11-NREC, PPR-SRV-CO-SBO, /RCS-MDP-LK-SEALS, OEP-XHE-NOREC-BD
LOOP Sequence 18-09		**3.9 E-005**	
1	51.3	2.0 E-005	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, EPS-DGN-FC-SBO, LOOP-18-09-NREC, /PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL
2	25.0	9.7 E-006	EPS-DGN-CF-AB, EPS-DGN-FC-SBO, LOOP-18-09-NREC, /PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL
3	6.6	2.6 E-006	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, ACP-XHE-BUS-D2, LOOP-18-09-NREC, /PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL
4	6.6	2.6 E-006	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, ACP-XHE-XE-ALT, LOOP-18-09-NREC, /PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL
5	3.9	1.5 E-006	EPS-DGN-CF-ALL, LOOP-18-09-NREC, /PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL
6	3.2	1.2 E-006	EPS-DGN-CF-AB, ACP-XHE-XE-ALT, LOOP-18-09-NREC, /PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL
7	3.2	1.2 E-006	EPS-DGN-CF-AB, ACP-XHE-BUS-D2, LOOP-18-09-NREC, /PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL
LOOP Sequence 18-18		**2.3 E-005**	
1	51.3	1.2 E-005	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, EPS-DGN-FC-SBO, LOOP-18-18-NREC, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL
2	25.0	5.7 E-006	EPS-DGN-CF-AB, EPS-DGN-FC-SBO, LOOP-18-18-NREC, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL
3	6.6	1.5 E-006	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, ACP-XHE-BUS-D2, LOOP-18-18-NREC, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL
4	6.6	1.5 E-006	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, ACP-XHE-XE-ALT, LOOP-18-18-NREC, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL

Table B.5.5. Conditional Cut Sets for Higher Probability Sequences for LER No. 346/98-006 (Continued)

Cut set number	Percent contribution	CCDP[a]	Cut sets[b]
5	3.9	8.8 E-007	EPS-DGN-CF-ALL, LOOP-18-18-NREC, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL
6	3.2	7.3 E-007	EPS-DGN-CF-AB, ACP-XHE-XE-ALT, LOOP-18-18-NREC, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL
7	3.2	7.3 E-007	EPS-DGN-CF-AB, ACP-XHE-BUS-D2, LOOP-18-18-NREC, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL
LOOP Sequence 18-20		**8.2 E-006**	
1	51.3	4.2 E-006	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, EPS-DGN-FC-SBO, LOOP-18-20-NREC, PPR-SRV-CO-SBO, PPR-SRV-OO-PORV, OEP-XHE-NOREC-ST
2	25.0	2.1 E-006	EPS-DGN-CF-AB, EPS-DGN-FC-SBO, LOOP-18-20-NREC, PPR-SRV-CO-SBO, PPR-SRV-OO-PORV, OEP-XHE-NOREC-ST
3	6.6	5.4 E-007	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, ACP-XHE-BUS-D2, LOOP-18-20-NREC, PPR-SRV-CO-SBO, PPR-SRV-OO-PORV, OEP-XHE-NOREC-ST
4	6.6	5.4 E-007	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, ACP-XHE-XE-ALT, LOOP-18-20-NREC, PPR-SRV-CO-SBO, PPR-SRV-OO-PORV, OEP-XHE-NOREC-ST
5	3.9	3.2 E-007	EPS-DGN-CF-ALL, LOOP-18-20-NREC, PPR-SRV-CO-SBO, PPR-SRV-OO-PORV, OEP-XHE-NOREC-ST
6	3.2	2.6 E-007	EPS-DGN-CF-AB, ACP-XHE-XE-ALT, LOOP-18-20-NREC, PPR-SRV-CO-SBO, PPR-SRV-OO-PORV, OEP-XHE-NOREC-ST
7	3.2	2.6 E-007	EPS-DGN-CF-AB, ACP-XHE-BUS-D2, LOOP-18-20-NREC, PPR-SRV-CO-SBO, PPR-SRV-OO-PORV, OEP-XHE-NOREC-ST
Total (all sequences)		**5.6 E-004**	

[a] The conditional probability for each cut set is determined by multiplying the probability of the initiating event by the probabilities of the basic events in that minimal cut set. The probabilities for the initiating events and the basic events are given in Table B.5.1.

[b] Basic events OEP-XHE-NOREC-2H, OEP-XHE-NOREC-6H, OEP-XHE-NOREC-SL, and OEP-XHE-NOREC-ST are TRUE type events which are not normally included in the output of fault tree reduction programs but have been added to aid in understanding the sequences to potential core damage associated with the event.

B.6 LER No. 346/98-011

Event Description: Manual reactor trip while recovering from a component cooling system leak and de-energizing safety-related bus D1 and nonsafety-related bus D2

Date of Event: October 14, 1998

Plant: Davis-Besse 1

B.6.1 Event Summary

The Davis-Besse plant was in Mode 1 at 100% power on October 14, 1998, when a lockout of essential bus D1, nonessential bus D2, and the station blackout (SBO) diesel generator (DG) occurred.[1] The bus lockout occurred when an electrician rolled circuit breaker AACD1 back into its cubicle after performing preventive maintenance. As the breaker was rolled back, the metal breaker frame contacted a terminal screw of a time-over-current relay mounted on the cubicle door and actuated the relay. This relay provides backup ground protection for buses D1 and D2. Loss of bus D2 caused the loss of condensate pump 1-2 and, as a result, the operators initiated a plant power reduction. Before the lockout of buses D1 and D2, component cooling water pump (CCWP) 1-2 was in operation supplying nonessential loads. When bus D1 was lost, CCWP 1-2 and service water pump (SWP) 1-2 tripped. Tripping of CCWP 1-2 caused CCWP 1-1 to start automatically. The isolation valve that isolates the nonessential component cooling water (CCW) supply from CCWP 1-1 opened after a 30-s time delay. During that delay, no CCW flowed through the RCS letdown coolers resulting in the hot RCS coolant heating up the CCW inside the coolers. When the isolation valve on the pipeline from CCWP-1 to the nonessential CCW header opened, sub-cooled CCW flowed into the RCS letdown coolers causing the steam bubbles in the coolers to collapse. The collapsing of the steam bubbles created a pressure spike that damaged one of the two rupture disks on letdown cooler 1-1. At 1512, personnel restored power to essential buses D1 and F1. (Essential bus F1 is a 480-V ac bus powered by essential bus D1—a 4160-V ac bus.) At 1523, personnel restarted CCWP 1-2; restarting CCWP 1-2 caused the CCW surge tank level to drop rapidly because of the rapid loss of water from the CCW system through the ruptured disk. This prompted the operators to trip the reactor at 1523. By 1712, operators restored CCW and stabilized the plant. The conditional core damage probability (CCDP) estimated for this event is 1.5×10^{-5}.

B.6.2 Event Description

At 1356, on October 14, 1998, Davis-Besse was operating at 100% power, when a lockout of essential bus D1, nonessential bus D2, and the SBO DG occurred. At this time, bus-tie transformer AC was de-energized; this bus-tie transformer can provide backup power to essential bus D1. Figure B.6.1 shows the arrangement of buses D1 and D2 and the associated breakers. After performing routine preventive maintenance on circuit breaker AACD1, an electrician rolled the breaker back into its cubicle. A misalignment between the floor rail and circuit breaker resulted in the breaker frame contacting a terminal screw; the short actuated the time-over-current relay that provides backup ground protection for buses D1 and D2. The opening of this relay resulted in deenergizing nonessential bus D2 and essential bus D1. The short also resulted in preventing the output breaker for the SBO DG (AD213) from closing. Emergency DG (EDG) 1-2 started on low voltage; however, its output breaker (AD101) could not close because it was locked out. Operators shut down EDG 1-2 anyway at 1401 because CCW was unavailable to cool the EDG. Because of the lockout of D1 and D2, CCWP 1-2 (powered from bus D1) and condensate pump 1-2 (powered from bus D2) were unavailable. In addition, all normal station lighting (powered from bus D2) was lost. Operators began reducing reactor power to stabilize power at a level within the capacity of the two available condensate pumps. Operators reduced power from 100% to ~87% by 1430. At 1415 (19 min after the bus lockout), operators declared turbine-driven auxiliary feedwater (AFW) pump AFP 1-1 operable although it was out of service for testing before the lockout event began.. The capability to inject feedwater into SG 1-1 from AFP 1-2 was lost because essential bus F1 supplies motive power to MOV-3871 and this valve was closed. AFP 1-2 is also a turbine-driven pump.

When the D1/D2 bus lockout occurred, CCWP 1-2 was operating and supplying non-essential CCW loads inside containment (see Fig. B.6.2). Troubleshooting was in progress on the discharge flow indicating switch (FIS1422D) for CCWP 1-1. When the bus lockout occurred and CCWP 1-2 tripped, CCWP 1-1 automatically started. The non-essential isolation valve in CCW Loop 1 (valve 5095) began to open after a 30-s delay. When CCWP 1-2 tripped, the nonessential isolation valve on CCW Loop 2 (valve 5096) received a signal to close; because of the D1/D2 bus lockout, motive power (480-V ac essential bus F1) was unavailable to close the valves. During the 30-s delay for the CCW Loop 1 non-essential isolation valve to begin stroking open, no coolant flow was provided to the RCS letdown coolers. Because of the hot reactor coolant flowing through the letdown coolers, the CCW in the coolers turned to steam. When the Loop 1 nonessential isolation valve opened and reinitiated flow to the letdown coolers, the sub-cooled CCW caused the steam pockets to collapse. The resultant pressure spike damaged one of the two rupture disks on letdown cooler 1-1. Alarms received during operation of the containment sump pump along with the low water level in the CCW surge tank indicated a leak of $1–3 \times 10^{-4}$ m^3/s (2–5 gpm) from the CCW system. Indications were that the leak had started inside containment.

By 1512 (76 min after the bus lockout), personnel had fixed the problem in bus cubicle AACD1. Restoration of power to the electrical buses began then. Re-energizing 480-V ac essential bus F1 restored power to the CCW Loop 2 non-essential isolation valve. Because of an "open" signal from FIS 1422D and a "close" signal from the breaker interlocks, CCW Loop 2 non-essential isolation valve (valve 5096) started to cycle open and closed. The valve continued to cycle until CCWP 1-2 was started. At 1517, operators successfully restarted service water pump (SWP) 1-2, followed by the restart of CCWP 1-2 at 1523. Both pumps are powered from essential bus D1. When CCWP 1-2 was started, the CCW surge tank level decreased rapidly. When the water level in the surge tank decreased to 88.9 cm (35 in.) and was still decreasing, operators tripped the reactor and the reactor coolant pumps (RCPs). This generated an automatic start signal to the AFW system. Natural circulation conditions were fully developed ~4 min after the RCPs tripped.

Following the reactor trip, the following events occurred: (1) the operators' attempt to start makeup pump 1-2 failed, (2) steam generator (SG) outlet pressure increased because of the closing of the main turbine stop valves, (3) the turbine bypass valves (TBVs) and the atmospheric vent valves (AVVs) opened and the main steam safety valves (MSSVs) lifted in response to the increasing pressure in the secondary system, (4) the MSSVs and the AVVs closed as the outlet pressure for the SGs decreased, and (5) the TBVs throttled closed as they attempted to control SG outlet pressure at the post-trip setpoint of ~6.86 MPa (995 psig). Following the reactor trip, operators determined that MSSV SP17B7 was not fully closed. By manually reducing the pressure in the main steam system to 6.34 MPa (920 psig), MSSV SP17B7 reseated. While actions were underway to investigate and recover from the loss of CCW to the containment and to recover electrical loads that were lost, the operators also had to initiate actions to reduce steam loads in the secondary system to terminate the overcooling of the reactor coolant system (RCS). Plant operators made preparations to restore CCW to the containment header while leaving CCW to the letdown coolers isolated. At 1712, personnel restored CCW to the containment header thereby providing cooling for the control rod drives and reactor coolant pumps (RCPs). This required operators to open CCW containment isolation valves CC1411A and B; these valves functioned as designed to isolate the leak from letdown cooler 1-1. Shortly after that, operators were able to restart RCPs 1-2 and 2-2, restoring forced-RCS coolant flow.

B.6.3 Additional Event-Related Information

Essential bus D1 and nonessential bus D2 supply power to components necessary for emergency and normal plant operation, respectively. Therefore, loss of power to these buses and the resulting decrease in RCS coolant flow increased the likelihood of a reactor trip. The power reduction started at 1356 from 100% power, and was terminated at 87% at 1430. At 1523, operators tripped the reactor.

The damage to the rupture disk on the RCS letdown heat exchanger worsened when CCWP 1-2 was started after power to bus D1 was recovered. (Power to bus D1 was recovered at 1512, or 76 min after the bus lockout.) The water level in the CCW surge tank dropped rapidly as a result of water flowing out the ruptured disk. CCW containment isolation valves CC1411A and CC1411B functioned as designed to isolate letdown cooler 1-1 within 10 s because of the low water level in the surge tank. Successfully isolating the leak maintained CCW system inventory levels and prevented net positive suction head problems for the CCW pumps. As Fig. B.6.2 shows, successful isolation of these valves not only affects the RCS letdown cooler, it also affects the CCW supply to all of the RCPs and control rod drives. That is, when either valve CC1411A or valve CC1411B closes, CCW cooling of the RCP seals will be lost. However, operators can close other valves remotely to allow isolation of the letdown heat exchangers while still providing RCP cooling to the RCP seals.

As shown in Fig. B.6.3, Davis-Besse has two turbine-driven auxiliary feedwater pumps (AFP 1-1 and AFP 1-2). If essential bus D1 is available, either of these pumps can provide feedwater to either of the steam generators. However, the loss of power to essential bus D1 caused power to be lost to essential bus F1. Bus F1 powers motor-operated valve AFW-3871, which is normally closed. Therefore, when bus D1 lost power, the capability to inject feedwater into steam generator SG 1-1 from AFP 1-2 was lost because valve AFW-3871 could not be opened. Although Davis-Besse also has a motor-driven feedwater pump, it was not available because it is powered from bus D2. Hence, if AFP 1-1 had failed, the capability of providing feedwater to SG 1-1 would be lost. Without feedwater, the steam supply from SG 1-1 to the turbine-driven AFW pumps would fail. As a result, with bus F1 failed, if AFP 1-1 fails, only SG 1-2 has the capability to supply steam to AFP 1-2. However, as Fig. B.6.3 shows, when bus D1 is failed, MOV 107 (normally closed) cannot be opened and SG 1-2 cannot provide steam to the turbine of AFP 1-2.

In summary, if AFP 1-1 fails when bus D1 is de-energized, then AFP 1-2 will fail because of a lack of steam. Because the motor-driven feedwater pump is powered from bus D2, all feedwater would be lost.

According to Ref. 2, when both trains of makeup pumps are available for feed-and-bleed cooling, opening both pressurizer safety valves is adequate to perform the bleed function. The pressurizer pilot-operated relief valve (PORV) is not essential. However, when essential bus D1 lost power, makeup pump 1-2 was not available. Under that condition, the PORV is essential to perform feed-and-bleed cooling. The pressurizer PORV is powered from Division 2 dc power. When bus D1 is de-energized, Division 2 dc power relies upon the Division 2 battery. When the battery's charge has been depleted, the PORV will fail and, as a result, feed-and-bleed cooling will fail. Therefore, if bus D1 is not recovered before the battery that powers the PORV is depleted, feed-and-bleed cooling will fail.

B.6.4 Modeling Assumptions

In modeling this event, three scenarios were examined.

Scenario 1

The first scenario was estimated using the standardized plant analysis risk (SPAR)-based model for Davis-Besse. The following sequence (sequence 20 on Fig. B.6.4) contributed 100% of the CCDP from this scenario:

- a reactor trip,
- unavailability of MFW,
- unavailability of AFW, and
- loss of high pressure injection (HPI) cooling (also known as feed-and-bleed cooling).

Probability of Reactor Trip (RT)

When buses D1 and D2 were lost, the reactor did not automatically trip. However, several systems or system trains that rely on buses D1 or D2 (e.g., condensate pump 1-2, cooling water pump 2, station air compressor, emergency air compressor, and heater drain pump 2) were without power. As a result, the operators had to reduce the power level from 100% to 87% over a 34-min period (from 1356 to 1430). The operators tripped the plant at 1523. The loss of essential and nonessential busses and changing the power level increased the likelihood of a reactor trip. Reference 3 (page 8-12) indicates that there were 10 reactor trips during 148 controlled plant shutdowns. Therefore, a value of 6.8×10^{-2} (10/148) was used to approximate the increased probability of a reactor trip occurring during this event (IE-TRNS). This is an increase from the base-case value in the SPAR-based model for Davis-Besse of 2.7×10^{-4}.

Unavailability of MFW (MFW-T)

Reference 1 notes that de-energizing bus D2 resulted in the loss of power to condensate pump 1-2. Besides this, station air compressor C140 is also powered from bus D2. Moreover, bus F7, which provides power to the emergency air compressor, was unavailable because it is powered by bus D2. One train of the turbine plant cooling water system was without power because bus D2 was without power. In consideration of all these dependencies, it was pessimistically assumed that the reactor trip was caused by the loss of, or a transient in, the

MFW system. Further, with essential bus D1 and nonessential bus D2 de-energized, the MFW system would not be available to remove decay heat after tripping the reactor.

Unavailability of AFW (AFW)

The loss of power to essential bus D1 caused power to be lost to essential bus F1. Bus F1 powers motor-operated valve AFW-3871, which is normally closed (and was closed when the transient began). Therefore, when bus D1 lost power, the capability to inject feedwater into steam generator SG 1-1 from AFP 1-2 was lost. If AFP 1-1 had failed, the capability of providing auxiliary feedwater to SG 1-1 would be lost. Without feedwater, the steam supply from SG 1-1 to the turbine-driven AFW pumps would fail.

In addition to the two turbine-driven AFW pumps and one motor-driven feedwater pump, Davis-Besse has another motor-driven feedwater pump—the startup feedwater pump. This pump can back up the AFW system. This pump was the original "motor-driven feedwater pump," but once the new motor-driven feedwater pump had been installed, it was essentially abandoned in place. Since then, however, the pump has been put back into the plant operating procedures and would be available if needed. It is powered from nonessential bus C2. Its breaker must be racked in, and there are manual isolation valves that must be opened locally. Conversely, the new motor-driven feedwater pump can be started from the control room and acts just like an AFW pump. For these reasons, the availability of the startup feedwater pump is lower than that for the new motor-driven feedwater pump. Therefore, if buses D1 and D2 had remained de-energized (i.e., one turbine-driven AFW pump and main feedwater is unavailable), and the other turbine-driven AFW pump failed or was unavailable, the startup feedwater pump could still have been used to provide water to the steam generators.

Loss of HPI (Feed-and-Bleed Cooling) (HPI-COOL)

If steam generator cooling using the AFW and MFW fails, decay heat can be removed by feed-and-bleed cooling. According to the Davis-Besse individual plant examination (IPE),[2] when only one makeup pump train is available, the pressurizer PORV is essential for feed-and-bleed cooling. During this transient, makeup pump 1-2 did not start because essential bus D1 was unavailable, leaving only one makeup train available. The PORV used for feed-and-bleed cooling requires power from Division 2 electrical supply. With essential bus D1 unavailable, the battery charger is unavailable and the battery will be depleted. If the dc electrical loads are not reduced, a typical battery at a nuclear power plant can be expected to last ~2 h. During this event at Davis-Besse, the electrical buses were lost for 76 min. Assuming a mean-time-to-repair (i.e., the time to recover power to the essential bus) of 75 min and an exponential distribution, the probability of failing to recover dc power in 2 h is 2.0×10^{-1}. Basic event D2N-RECHARGE was added to the SPAR-based model for Davis-Besse to model this failure.

Other likely failure modes for feed-and-bleed cooling include an operator failing to initiate high-pressure injection cooling (HPI-XHE-XM-HPIC), a PORV fails to open on demand (PPR-SRV-CC-PORV), failures in decay heat removal pump train P11 (DHR-MDP-FC-P11), failure of low-pressure injection train 11 discharge motor-operated valve DH64 to open (DHR-MOV-FC-DH64), failure of motor-driven charging pump train 1-1 (CVC-MDP-FC-MU11), failures in the charging discharge path (CVC-AOV-OC-DIS), and charging train suction valve MU 6405 fails (CVC-MOV-FC-SUC11).

Scenario 2

The second scenario, as shown in Fig. B.6.5, consists of

- loss of CCW because of a rupture disk failure in the RCS letdown heat exchanger,
- failure to isolate the rupture (automatically or via operator action),
- operator fails to trip the RCPs after the loss of CCW, leading to a seal LOCA.

Loss of CCW (IE-CCW)

Another scenario considered during the modeling of this event was the potential loss of all CCW because of the rupture disk failure in the RCS letdown cooler. The design of the CCW is such that, when the running CCW pump stops and the standby CCW pump starts, steam will form inside the RCS letdown heat exchanger during the 30 s it takes to open the isolation valve from the standby CCW train to its nonessential supply. When bus D1 deenergized, CCWP 1-2 tripped. CCWP 1-1 started automatically. Starting the standby CCW pump caused the steam in the letdown heat exchanger to collapse, thereby damaging a rupture disk in the letdown heat exchanger. The resulting isolable leakage was 1–3 $\times$ 10^{-4} m^3/s (2–5 gpm). Subsequently, after personnel recovered electric power and restarted CCWP 1-2, the water level in one side of the CCW surge tank decreased rapidly (the CCW surge tank at Davis-Besse has two sides with a dividing wall between them) and the leak from the damaged rupture disk increased. (CCWP 1-2 had been operating prior to the loss of buses D1 and D2.) The low water level in the surge tank generated a signal to close CCW containment isolation valves CC1411A and CC1411B, thereby stopping the flow of CCW to the RCS letdown heat exchanger. The other side of the tank could have been depleted fully only if the operators had failed to isolate the nonessential loads and had aligned CCWP 1-1 to supply them from the second side of the surge tank.

Failure to Isolate the Rupture (ISOLATE)

There are two CCW containment isolation valves (CC1411A and CC1411B) that receive automatic signals to isolate the nonessential CCW header on a low water level in the surge tank. If a rupture disk failure occurred in the RCS letdown cooler and if both valves failed to isolate the rupture, the water level in the CCW would continue to drain down. Note that valves CC1411A and B are redundant isolation valves that receive isolation signals from redundant sources. Further, a low water level alarm for the surge tank will also let the operator know of the need to isolate the tank—as it did during this event. Considering the probabilities of the various failure modes to isolate the nonessential CCW header (the failure of CC1411A and B to close, the failure of the redundant automatic signals to isolate the surge tank, the failure of the operator to recognize and intervene in response to a low water level in the surge tank, and the failure of the containment normal sump pump alarms to annunciate), the common-cause mechanical failure of the two isolation valves to close is dominant. The SPAR-based model for Davis-Besse uses a probability of 2.6 $\times$ 10^{-4} for the common-cause failure probability of two MOVs failing to close.

Operator Fails to Trip the RCPs (TRIPRCP)

If CCW fails, procedures instruct the operators to trip the RCPs because the failure to trip the RCPs under these conditions will lead to an RCP seal LOCA. In addition, alarms will indicate to the operator if the RCP seal temperature is too high. Under this transient condition, a probability of 1.0×10^{-3} represents an upper bound for the probability of the operator failing to trip the RCPs.[4]

The probability of an RCP seal LOCA from this sequence is less than 2.6×10^{-7} [i.e., 2.6×10^{-4} (failure to isolate the ruptured heat exchanger) $\times$ 1.0×10^{-3} (operator fails to trip the RCPs)].

Scenario 3

The third scenario, as shown in Fig. B.6.5, consists of

- loss of CCW because of a rupture disk failure in the RCS letdown heat exchanger,
- failure to isolate the rupture (automatically or via operator action),
- the operator successfully trips the RCPs,
- failure to recover CCW and to restore cooling to the RCP seals before seal damage leads to an RCP seal-LOCA, and
- failure to recover HPI (or makeup) pumps prior to core uncovery.

Loss of CCW (IE-CCW)

When bus D1 deenergized, CCWP 1-2 tripped. CCWP 1-1 started automatically. Starting the standby CCW pump caused the steam in the letdown heat exchanger to collapse, thereby damaging a rupture disk in the letdown heat exchanger. The resulting isolable leakage was $1–3 \times 10^{-4}$ m^3/s (2–5 gpm). Subsequently, after personnel recovered electric power and restarted CCWP 1-2, the water level in one side of the CCW surge tank decreased rapidly and the leak from the damaged rupture disk increased. The low water level in the surge tank generated a signal to close CCW containment isolation valves CC1411A and CC1411B, thereby stopping the flow of CCW to the RCS letdown heat exchanger. The other side of the tank could have been depleted fully only if the operators had failed to isolate the nonessential loads and had aligned CCWP 1-1 to supply them from the second side of the surge tank.

Failure to isolate the rupture (ISOLATE)

There are two CCW containment isolation valves (CC1411A and CC1411B) that receive automatic signals to isolate the nonessential CCW header on a low water level in the surge tank. If a rupture occurred in the RCS letdown cooler and if both valves failed to isolate the rupture, the water level in the CCW surge tank would continue to drain down. The common-cause mechanical failure of the two isolation valves to close will dominate the failure probability of failing to isolate the rupture. The SPAR-based model for Davis-Besse uses a probability of 2.6×10^{-4} for the common-cause failure probability of two MOVs failing to close.

Operator successfully trips the RCPs (TRIPRCP)

If CCW fails, procedures instruct the operators to trip the RCPs because the failure to trip the RCPs under these conditions will lead to an RCP seal LOCA. In addition, alarms will indicate to the operator if the RCP seal temperature is too high. It is extremely likely that operators will trip the RCPs (probability = 0.997).

Failure to recover CCW prior to RCP seal failure (SEALS)

CCWP 1-3 was the spare pump at the time of the event. This pump can be aligned electrically to either Division 1 (bus C1) or Division 2 (bus D1). Thus, operators could have aligned CCWP 1-3 as a backup to CCWP 1-1 if it had failed to start, or to CCWP 1-2 after personnel restored power to bus D1. This would have required manually racking in the pump breaker at the 4-kV switchgear and opening two manual isolation valves. Plant procedures cover these actions explicitly and the IPE gives reasonable credit to their success.

There is a procedure for loss of CCW that specifies recovery actions using the spare pump. If CCW is unavailable, the procedure assumes that the makeup pump(s) would fail because of lack of cooling within about 10 min. The operators would then have about another 15 min to restore CCW to the RCP seals if the RCP pumps were not tripped. After that, a seal LOCA would result, and HPI would actuate. The HPI pumps are expected to operate for at least 1 h without CCW. Thus, the operators would have about 1-h and 25 min to restore CCW.

The RCS can be cooled down quite rapidly by AFW. If the operators trip the RCPs as called for by the procedure, the ability to cool down is diminished. With CCW unavailable, there would be no makeup to compensate for water shrinkage in the RCS. Thus, there is a possibility to draw a bubble in the RCS during the cooldown that could interrupt natural circulation through the steam generators. This should not be permanent because natural circulation cooling should be restored as the RCS heats back up; however, it would impede the cooldown efforts. Of course, this is largely a moot point if tripping the RCPs precludes a seal failure.

Without CCW, RCP seal cooling is unavailable. Unavailability of RCP seal cooling may result in an RCP seal failure and a small-break LOCA. In this analysis, the probability of an RCP seal LOCA was assumed to be zero up to 60 min after a loss of seal cooling. Between 60–90 min, the probability of an RCP seal LOCA was assumed to increase linearly to 8.3×10^{-2} at 90 min (i.e., 2.8×10^{-3}/min). After 90 min, no additional seal failures were assumed to occur. This type of seal failure model is similar to that used in the ASP Program for modeling station blackout sequences.[5]

Failure to recover HPI (or makeup) pumps prior to core uncovery (HPI/MAKEUP)

At Davis-Besse, the HPI pump bearing oil is cooled by CCW. However, in the event of a loss of CCW, the HPI pumps will not fail immediately. That is, if CCW can be recovered within a reasonable time, failure of HPI and core uncovery can be averted. First, if CCW is lost and not recovered prior to seal failure, a finite time can elapse prior to core uncovery. Information provided in Table 3-11 of the Davis-Besse IPE (basic event UHAMUISE) indicates that ~1 h would be available to mitigate this accident before core uncovery occurs. If the operators start the HPI pumps without CCW available (since running the HPI pumps without lube oil cooling is preferred over uncovering the core), the pumps can run for a finite time prior to failure. Considering the uncertainties related to operator actions and timing (e.g., whether the operators would secure the HPI pumps when they automatically start without CCW available, whether one pump will be allowed to run while the other is secured), this analysis assumed 1 h would be available to run the HPI pumps prior to pump failure because of a loss of lube oil cooling. The combined effect of the time to core uncovery and the time that the HPI pumps can run without lube oil cooling leads to the assumption that there are 2 h available following an RCP seal LOCA with CCW unavailable to recover CCW in order to avoid core damage.

Therefore, the probability of this accident scenario involving (1) the loss of CCW as a result of failing to isolate the heat exchanger (2.6×10^{-4}), (2) failing to recover component cooling water prior to RCP seal failure, and (3) failing to recover HPI (or makeup) pumps prior to core uncovery, can be calculated as follows:

$$= 2.6 \times 10^{-4} \times \int f_{SL}(t) \times P_{ccwnr}(t + 2)\, dt$$

where, $f_{SL}(t)$ is the failure rate for RCP seals at time t and $P_{ccwnr}(t)$ is the probability of nonrecovery of CCW at time t. Time t is measured from the time of losing CCW. In this model, $f_{SL}(t)$ is zero between 0–60 min and 2.8×10^{-3}/min between 60–90 min. When t is greater than 90 min, f_{SL} is zero.

$P_{ccwnr}(t)$ can be modeled using an exponential model (i.e., $P_{ccwnr}(t) = e^{-\lambda t}$ where λ is the failure rate). Recovery of CCW would require manual isolation of the CCW nonessential containment header, refilling the CCW piping and surge tank, venting the system, and potentially realigning the CCW system to allow use of the spare pump. A review of Table 3-12 in the 1993 IPE submittal for Davis-Besse identified several recovery actions in the 1–4 h and greater than 4 h time frames that are similar to what is required in this case. For these actions, the IPE estimates failure probabilities on the 0.03–0.05 range. Assuming a nonrecovery probability of 0.03 at 4 h will result in λ being equal to 0.88 per h or 0.015 per min. Therefore, the probability of this scenario is

$$= 2.6 \times 10^{-4} \times \int_{60}^{90} 2.8 \times 10^{-3} \times \exp^{-0.0146\,(t + 120)}\, dt$$

$$= 1.3 \times 10^{-6}.$$

B.6.5 Analysis Results

Three different scenarios were considered. The CCDP associated with scenario 1 (reactor trip followed by loss of steam generator cooling), estimated using the SAPHIRE-based model for Davis-Besse is 1.4×10^{-5}. The CCDP associated with scenario 2 (loss of CCW followed by the operators failing to trip RCPs leading to a RCP seal LOCA was eliminated because it is below the precursor threshold value of 1.0×10^{-6}. Scenario 3 (loss of CCW, RCPs tripped, nonrecovery of CCW leading to RCP seal LOCA, and nonrecovery of CCW leading to HPI failure) has a CCDP of 1.3×10^{-6}. Therefore, the total CCDP is estimated to be 1.5×10^{-5}. The dominant sequence for this event involves a reactor trip while power is unavailable to buses D1 and D2, main feedwater is unavailable, turbine-driven auxiliary feedwater pump TDAFP 1-1 fails, the startup feedwater pump is unable to provide steam generator cooling, and feed-and-bleed cooling fails because of depletion of the Division 2 battery prior to recovery of Division 2 essential bus D1. The dominant sequence, Sequence 20 on Fig. B.6.4, involves

- a reactor trip while changing power level,
- unavailability of main feedwater,
- failure of turbine-driven AFP 1-1 (that fails AFP 1-2 as well because no steam is provided to its turbine),
- failure of the motor-driven startup feedwater pump,
- failure to recover bus D1 before the Division 2 battery is depleted.

Definitions and probabilities for selected basic events for scenario 1 are shown in Table B.6.1. The conditional probabilities associated with the highest probability sequences for scenario 1 are shown in Table B.6.2. Table B.6.3 lists the sequence logic associated with the sequences listed in Table B.6.2. Table B.6.4 describes the system names associated with the dominant sequences for scenario 1. Minimal cut sets associated with the dominant sequences for scenario 1 are shown in Table B.6.5. The CCDPs associated with scenarios 2 and 3 are shown in Table B.6.6, while Table B.6.7 lists the sequence logic associated with the scenarios listed in Table B.6.6. Table B.6.8 provides the definitions and failure probabilities for event tree branch points in Fig. B.6.5.

B.6.6 References

1. LER 346/98-011, "Manual Reactor Trip Due to Component Cooling Water System Leak." November 13, 1998.

2. Davis-Besse Unit 1, *Individual Plant Examination*, February 26, 1993.

3. J. D. Andrachek, et. al., "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," WCAP-14334-NP-A, Rev. 1, May 1995.

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

5. *Revised LOOP Recovery and RCP Seal LOCA models*, ORNL/LTR-89/11, August 1989.

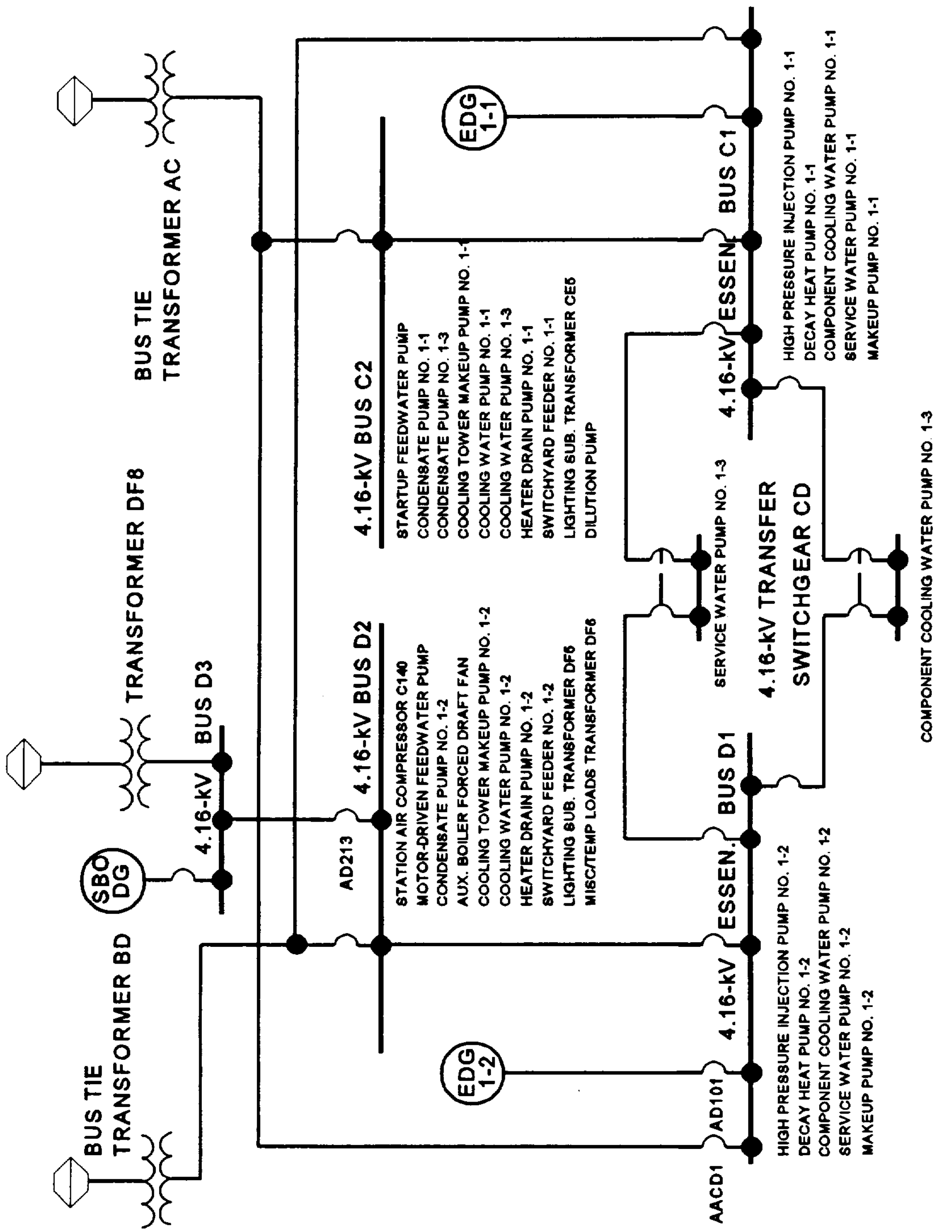

Fig. B.6.1 Electrical one-line diagram for Davis-Besse (*source: Davis-Besse Nuclear Power Station No. 1 Updated Safety Analysis Report*).

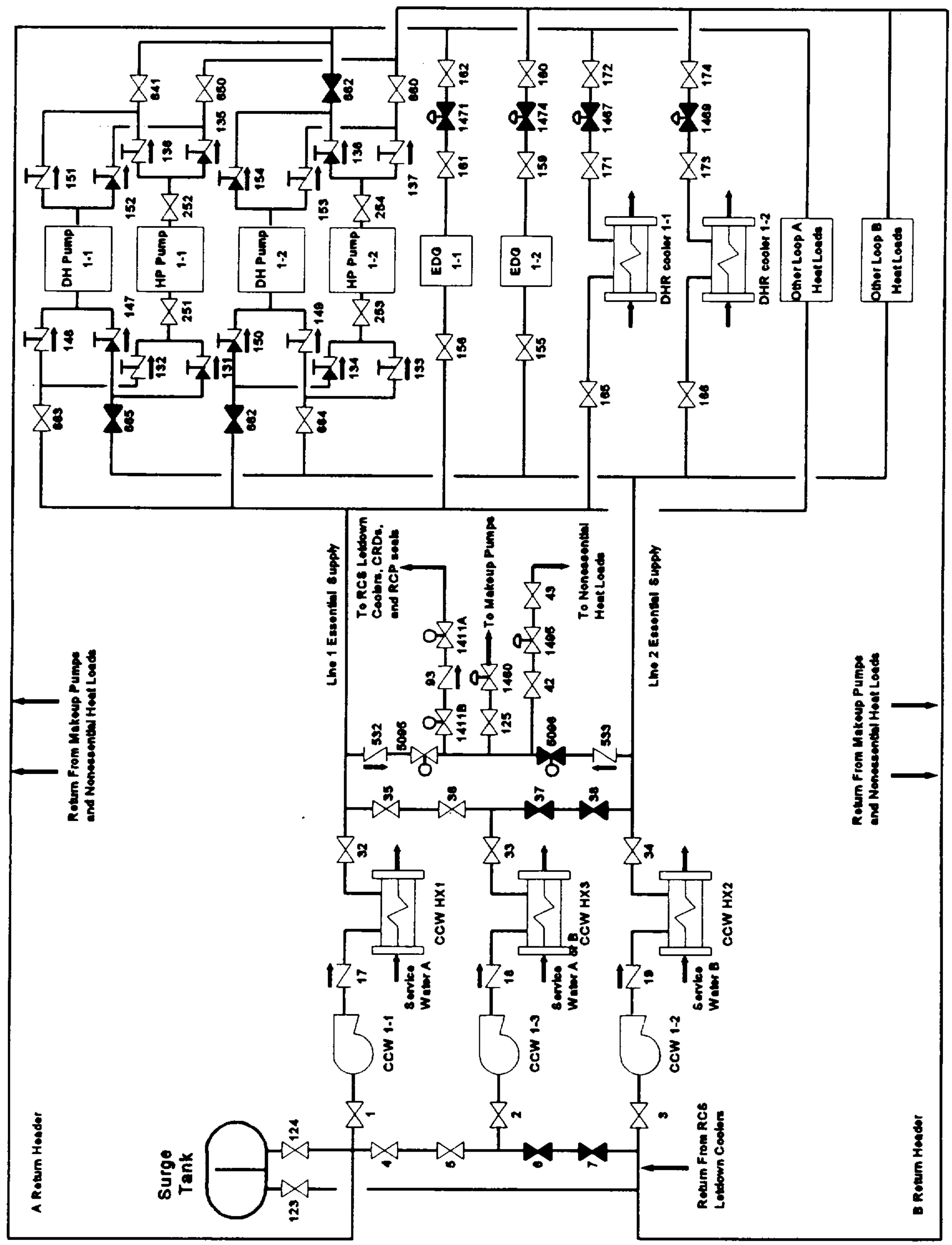

Fig. B.6.2 Davis-Besse component cooling water system and essential cooling loops (*source: Davis-Besse Nuclear Power Station No. 1 Updated Safety Analysis Report*).

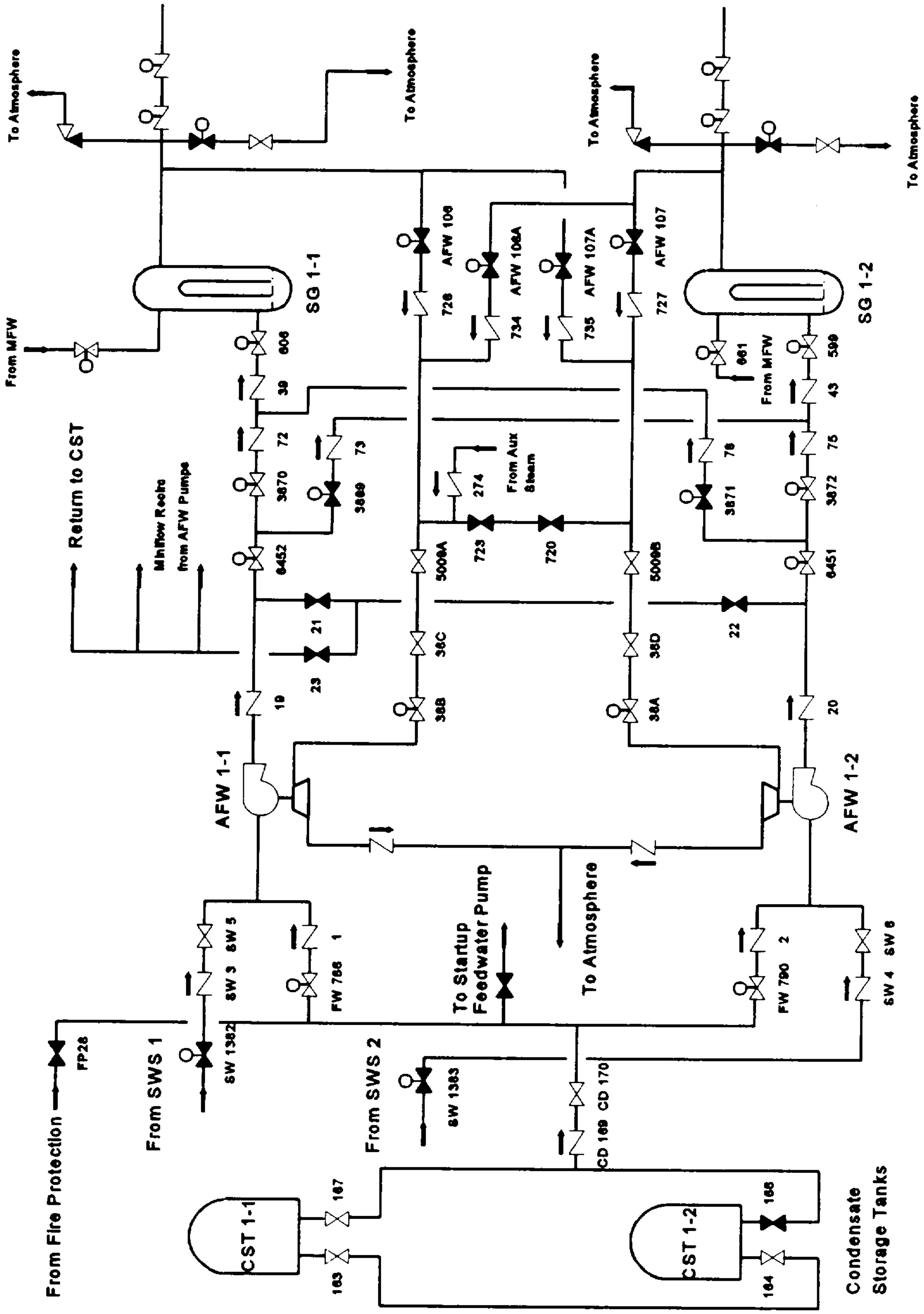

Fig. B.6.3 Davis-Besse auxiliary feedwater and secondary steam relief systems (*source: Davis-Besse Nuclear Power Station No. 1 Updated Safety Analysis Report*).

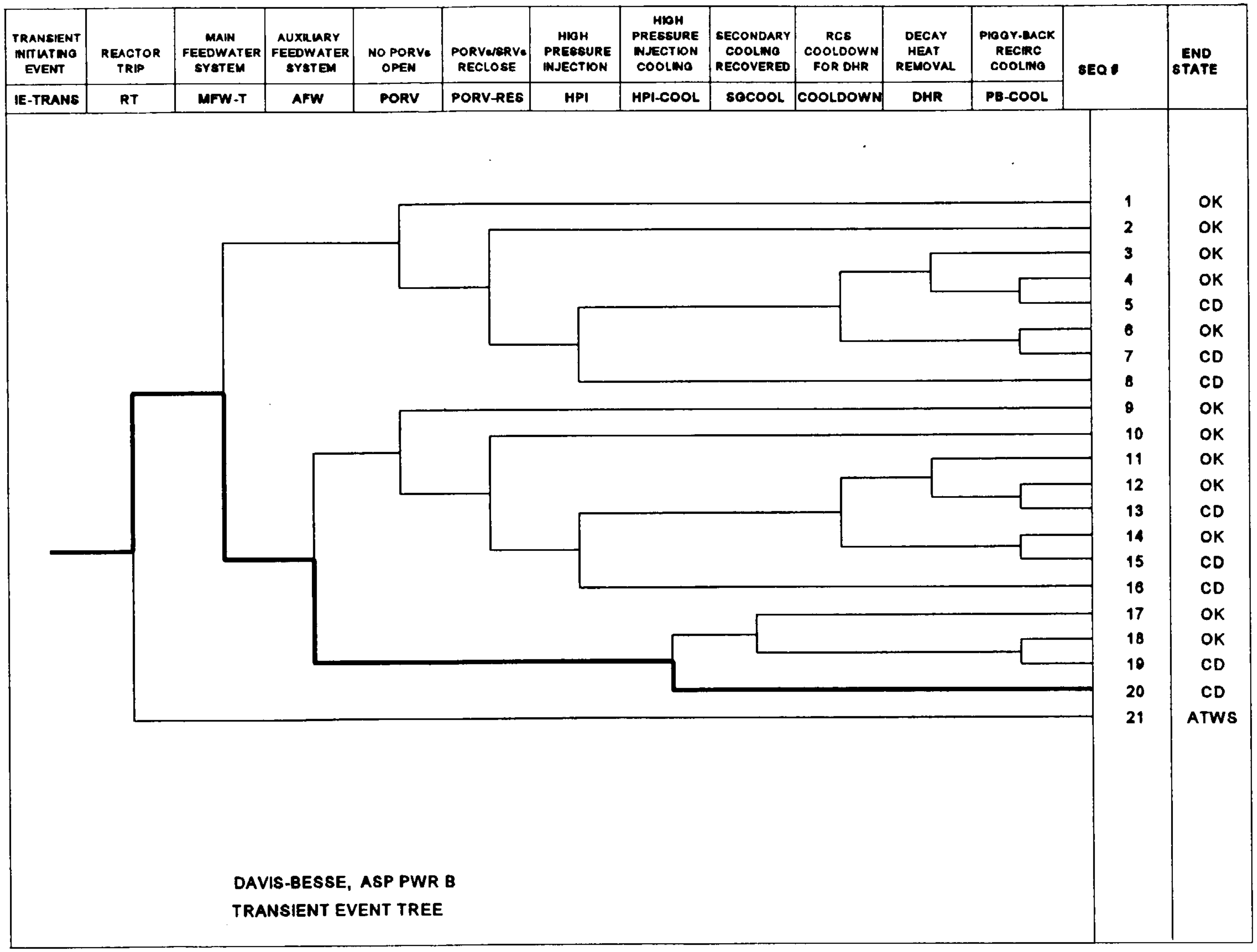

Fig. B.6.4 Dominant core damage sequence for scenario 1 for LER No. 346/98-011.

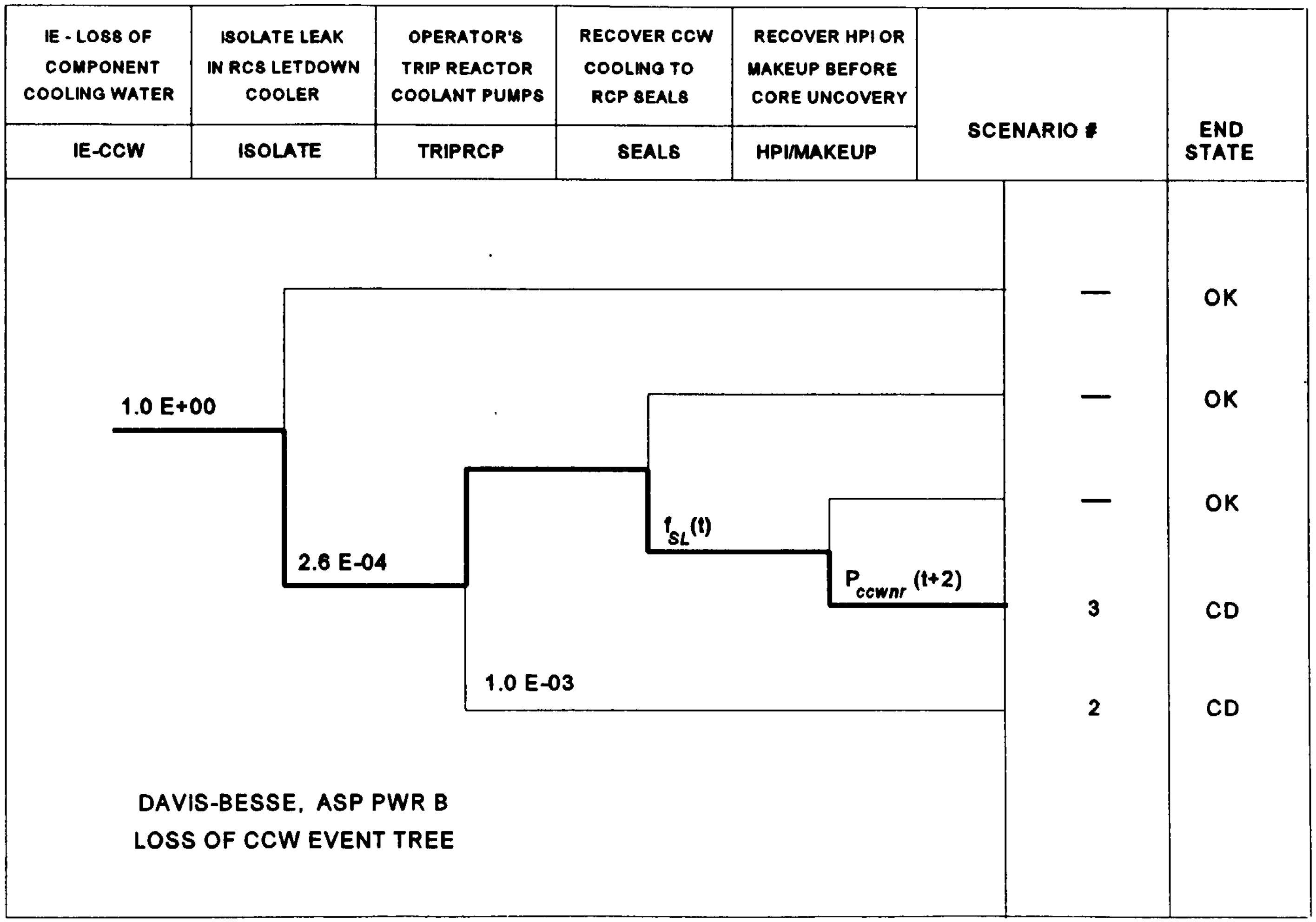

Fig. B.6.5 Dominant core damage sequences for scenarios 2 and 3 for LER No. 346/98-011.

Table B.6.1. Definitions and Probabilities for Selected Basic Events for Scenario 1 for LER No. 346/98-011

Event name	Description	Base probability	Current probability	Type	Modified for this event
IE-LOOP	Initiating Event–Loss of Offsite Power	1.6 E-005	0.0 E+000		No
IE-SGTR	Initiating Event–Steam Generator Tube Rupture	1.6 E-006	0.0 E+000		No
IE-SLOCA	Initiating Event–Small Loss-of-Coolant Accident (SLOCA)	2.3 E-006	0.0 E+000		No
IE-TRANS	Initiating Event-General Transient	2.7 E-004	6.8 E-002		Yes
ACP-BAC-LP-D1	Division B ac Power 4160-V Bus D1 fails	9.0 E-005	1.0 E+000	TRUE	Yes
ACP-BAC-LP-D2	Division B ac Power 4160-V Bus D2 fails	9.0 E-005	1.0 E+000	TRUE	Yes
AFW-MDP-FC-SUFP	Startup Feedwater Pump Fails to Start and Run	3.8 E-003	3.8 E-003		No
AFW-TDP-CF-ALL	Common-Cause Failure of Auxiliary Feedwater (AFW) Turbine-Driven Trains	3.2 E-003	3.2 E-003		No
AFW-TDP-FC-P11	Turbine-driven AFW Pump Train P11 Failures	3.5 E-002	3.5 E-002		No
AFW-XHE-XE-SUFP	Operator Fails to Start and Align Startup Feedwater Pump	1.0 E-001	1.0 E-001	NEW	Yes
CVC-MDP-FC-MU11	Motor-Driven Charging Pump Train 1 Failures	3.8 E-003	3.8 E-003		No
CVC-AOV-OC-DIS	Charging Discharge Path Failures	3.1 E-003	3.1 E-003		No
CVC-MOV-FC-SUC11	Charging Train Suction Valve MU 6405 Fails	3.0 E-003	3.0 E-003		No
D2N-RECHARGE	Failure to Recover Division 2 Battery Charger within 2 h	2.0 E-001	2.0 E-001	NEW	Yes
DHR-MDP-FC-P11	Decay Heat Removal Pump Train P11 Failures	4.0 E-003	4.0 E-003		No
DHR-MOV-FC-DH64	Failure of Low-Pressure Injection Train 11 Discharge Motor-Operated Valve DH64	3.0 E-003	3.0 E-003		No

Table B.6.1. Definitions and Probabilities for Selected Basic Events for Scenario 1 for LER No. 346/98-011 (Continued)

Event name	Description	Base probability	Current probability	Type	Modified for this event
HPI-XHE-XM-HPIC	Operator Fails to Initiate High-Pressure Injection Cooling	1.0 E-002	1.0 E-002		No
MFW-SYS-UNAVAIL	Main Feedwater System Unavailable	2.0 E-001	1.0 E+000	TRUE	Yes
PPR-SRV-CO-TRAN	Pilot-Operated Relief Valve/Safety Relief Valves (PORV/SRVs) Open During Transient	8.0 E-002	8.0 E-002		No
PPR-SRV-CC-PORV	PORV Fails to Open on Demand	6.3 E-003	6.3 E-003		No
TRANS-20-NREC	Trans Sequence 20 Nonrecovery Probability—Failure to Recover AFW (2.6×10^{-1}) and Failure to Recover Feed-and-Bleed Cooling (8.4×10^{-1})	2.2 E-001	2.2 E-001		No

Table B.6.2. Sequence Conditional Probabilities for Scenario 1 for LER No. 346/98-011

Event tree name	Sequence number	Conditional core damage probability (CCDP)	Percent contribution
TRANS	20	1.4 E-005	100.0
Total (all sequences)		**1.4 E-005**	

Table B.6.3. Sequence Logic for Dominant Sequences for Scenario 1 for LER No. 346/98-011

Event tree name	Sequence number	Logic
TRANS	20	/RT, MFW-T, AFW, HPI-COOL

Table B.6.4. System Names for Scenario 1 for LER No. 346/98-011

System name	Logic
AFW	No or Insufficient AFW Flow
HPI-COOL	Failure to Provide HPI Cooling (feed-and-bleed cooling)
MFW-T	Failure of the Main Feedwater System During Transient
RT	Reactor Fails to Trip During Transient

Table B.6.5. Conditional Cut Sets for Higher Probability Sequences for Scenario 1 for LER No. 346/98-011

Cut set number	Percent contribution	Conditional probability[a]	Cut sets
TRANS Sequence 20		1.4 E-005	
1	74.9	1.0 E-005	MFW-SYS-UNAVAIL, AFW-TDP-FC-P11, AFW-XHE-XE-SUFP, D2N-RECHARGE, TRANS-20-NREC
2	6.9	9.5 E-007	MFW-SYS-UNAVAIL, AFW-TDP-CF-ALL, AFW-XHE-XE-SUFP, D2N-RECHARGE, TRANS-20-NREC
3	3.8	5.2 E-007	MFW-SYS-UNAVAIL, AFW-TDP-FC-P11, AFW-XHE-XE-SUFP, HPI-XHE-XM-HPIC, TRANS-20-NREC
4	2.9	3.9 E-007	MFW-SYS-UNAVAIL, AFW-TDP-FC-P11, AFW-MDP-FC-SUFP, D2N-RECHARGE, TRANS-20-NREC
5	2.4	3.3 E-007	MFW-SYS-UNAVAIL, AFW-TDP-FC-P11, AFW-XHE-XE-SUFP, PPR-SRV-CC-PORV, TRANS-20-NREC
6	1.5	2.1 E-007	MFW-SYS-UNAVAIL, AFW-TDP-FC-P11, AFW-XHE-XE-SUFP, DHR-MDP-FC-P11, TRANS-20-NREC
7	1.4	2.0 E-007	MFW-SYS-UNAVAIL, AFW-TDP-FC-P11, AFW-XHE-XE-SUFP, CVC-MDP-FC-MU11, TRANS-20-NREC
8	1.4	1.6 E-007	MFW-SYS-UNAVAIL, AFW-TDP-FC-P11, AFW-XHE-XE-SUFP, CVC-AOV-OC-DIS, TRANS-20-NREC
9	1.1	1.6 E-007	MFW-SYS-UNAVAIL, AFW-TDP-FC-P11, AFW-XHE-XE-SUFP, CVC-MOV-FC-SUC11, TRANS-20-NREC
10	1.1	1.6 E-007	MFW-SYS-UNAVAIL, AFW-TDP-FC-P11, AFW-XHE-XE-SUFP, DHR-MOV-CC-DH64, TRANS-20-NREC
Total (all sequences)		**1.4 E-005**	

[a]The conditional probability for each cut set is determined by multiplying the probability of the initiating event by the probabilities of the basic events in that minimal cut set. The probabilities for the initiating events and the basic events are given in Table B.6.1.

Table B.6.6. Conditional Probabilities for Scenarios 2 and 3 for LER No. 346/98-011

Event tree name	Scenario number	Conditional core damage probability (CCDP)	Percent contribution
CCW	2	2.6 E-007	16.7
CCW	3	1.3 E-006	83.3
Total (all sequences)		**1.5 E-006**	

Table B.6.7. Sequence Logic for Scenarios 2 and 3 for LER No. 346/98-011

Event tree name	Sequence number	Logic
CCW	2	ISOLATE, TRIPRCP
CCW	3	ISOLATE, /TRIPRCP, SEALS, HPI/MAKEUP

Table B.6.8. System Names for Scenarios 2 and 3 for LER No. 346/98-011

System name	Description	Failure probability
IE-CCW	Initiating Event–Loss of CCW	1.0 E+000
ISOLATE	Failure to Isolate Leak in RCS Letdown Cooler	2.6 E-004
TRIPRCP	Failure to Trip Reactor Coolant Pumps	1.0 E-003
SEALS	Failure to Recover CCW Cooling to RCP Seals Before Seal Failure	$f_{SL}(t)$
HPI/MAKEUP	Failure to Recover HPI or Makeup Pumps Before Core Uncovery	$P_{ccnwr}(t+2)$

B.7 LER No. 361/98-003

Event Description: Inoperable sump recirculation valve

Date of Event: February 5, 1998

Plant: San Onofre, Unit 2

B.7.1 Event Summary

San Onofre, Unit 2, was in a mid-cycle outage when personnel discovered that the linestarter for the containment emergency sump outlet valve was jammed because of grit in the sliding cam. The grit would have prevented the valve from opening on a recirculation actuation signal (RAS). This would result in one inoperable train while in the recirculation mode of the Emergency Core Cooling System (ECCS) and the Containment Spray (CS) system. This condition existed for ~18 d until the unit shut down for a mid-cycle outage. The core damage probability (CDP) at San Onofre 2 increased during these 18 d because of the increased susceptibility that would result from any loss-of-coolant accident (LOCA) that progressed to the recirculation phase. The estimated increase in the CDP (i.e., the importance) for this event is 7.2×10^{-6}.

B.7.2 Event Description

On February 5, 1998, utility electricians were replacing Square D linestarters as part of planned maintenance. The electricians discovered the mechanical interlock on the linestarter for the Train A containment emergency sump outlet valve (HV-9305) jammed. The sump outlet valve was in the closed position at the time the failure was discovered, fulfilling the containment isolation function of the valve (Fig. B.7.1). However, the as-found condition of the linestarter would have prevented valve HV-9305 from opening. Consequently, the recirculation function for Train A of High Pressure Safety Injection (HPSI) and CS could not be fulfilled without some recovery action. The Train A containment emergency sump outlet valve was last cycled open and closed on January 6, 1998. San Onofre, Unit 2, was shut down for the mid-cycle outage on January 24, 1998. Therefore, from the nature of the failure, the licensee considered the Train A containment emergency sump outlet valve inoperable for approximately 18 d before it was no longer required by Technical Specifications. Consequently, the ECCS Train A and CS Train A were inoperable for ~18 d.[1]

B.7.3 Additional Event-Related Information

The licensee had been programmatically replacing all of the Square D linestarters—60 of 86 linestarters in Unit 2, and 61 of 86 linestarters in Unit 3 had already been replaced. All remaining old linestarters (26 at Unit 2 and 25 at Unit 3) were replaced; no additional failures were discovered.[1]

The grit that caused the linestarter for the Train A containment emergency sump outlet valve to jam was identified as Portland cement particles.[2] No grit was discovered on or around other switchgear room components or in the ventilation ducts. However, some grit was found in other 480-V ac motor control center buckets, but it had not affected the operation of the associated linestarters. The grit was assumed to have been introduced before plant startup and was known not to migrate after being deposited.[1]

The HPSI system has three centrifugal pumps divided among two trains (Fig. B.7.1). Pump P-017 is in Train A and pump P-019 is in Train B. The third pump, P-018, is a swing pump and can be aligned to either train on the suction or discharge side. P-018 is normally aligned to Train A. Because the HPSI pumps do not automatically stop in response to an RAS signal, operators are directed to stop the pumps before the water level in the refueling water storage tank (RWST) decreases below 5%.[3]

While the recirculation phase of ECCS Train A was compromised between January 6, 1998, and January 24, 1998, the opposite train—ECCS Train B—was inoperable six times during this same period. These six occasions were for

1. 1 h, 43 min to perform an in-service test of an HPSI pump (January 12, 1998),
2. 27 h, 5 min to repair a Component Cooling Water (CCW) heat exchanger tube leak (January 13, 1998) (CCW is required to support ECCS.),
3. 6 h, 36 min to perform heat treatment of the main condenser (January 16, 1998). (This treatment process increases the heat load on the salt water cooling (SWC) system, which is required to support ECCS.),
4. 19 min to swap the in-service SWC pump to the opposite train (January 22, 1998),
5. 5 h, 45 min to perform maintenance work on the Train B RWST outlet valve's breaker-position indicating light replacement (January 23, 1998), and
6. 5 h, 31 min to perform an additional heat treatment of the main condenser (January 24, 1998).

B.7.4 Modeling Assumptions

This event was modeled as an 18-d (432-h) condition assessment with the Train A containment emergency sump outlet valve failed (valve HV-9305). The CCW heat exchanger maintenance (27 h, 5 min) was included in the modeling because of the time required to back out of the maintenance. The maintenance period with the unavailable RWST outlet valve (5 h, 45 min) was not included in the event model because the valve was deenergized in the open position, making Train B available during the injection phase of an accident. Time was considered available to manually close the RWST outlet valve before recirculation or to discontinue repairs and make the valve available remotely. Likewise, the two periods involving heat treatment of the main condenser (6 h, 36 min and 5 h, 31 min) were not included in the model of this event because any heat treatment would likely be terminated quickly by the operator. Even if this were not done, a turbine trip initiated by a LOCA would self-limit any added heat loads on the SWC system. The in-service test of the Train B HPSI pump (1 h, 43 min) was not modeled because of operator staffing for the test, the ability to restore the normal lineup quickly, and the limited time the pump was unavailable. The time required to swap pumps (19 min) was not modeled because of the limited time required to perform the task. Therefore, two distinct cases, totaling 432 h (18 d), were modeled as part of this event.

Case 1. 404 h, 55 min with only the Train A containment emergency sump outlet valve failed (valve HV-9305).
Case 2. 27 h, 5 min with the Train A containment emergency sump outlet valve failed (valve HV-9305) and CCW Train B unavailable.

The CS pumps are not represented in the Integrated Reliability and Risk Analysis System (IRRAS) model for San Onofre. However, because Train B of the CS system and all of the containment emergency fan coolers were available throughout the 18-d event, no attempt was made to incorporate the unavailability of one train of CS into the IRRAS model for San Onofre. This is estimated to have an insignificant impact on the calculated importance of this event because CS impacts containment pressure and not core cooling.

The failed Train A containment emergency sump outlet valve was modeled by setting basic event HPR-SMP-FC-UMPA (Containment Sump A Failure) failure probability from 6.1×10^{-3} to TRUE (i.e., probability = 1.0 that the valve would fail on demand). Because of multiple locations which were discovered with grit, previous operational success of the linestarters does not preclude the grit failure mechanism from simultaneously affecting more than one linestarter. In fact, multiple safety components are affected by this failure mechanism; however, most of the affected equipment is not identified. Therefore, only the sump isolation motor-operated valves were considered for adjustment of the common-cause treatment. No supporting evidence was available which would suggest that the failure of the Train A containment emergency sump outlet valve linestarter was unique to just this one linestarter. Therefore, the associated common-cause failure basic event (HPR-MOV-CF-SUMP) was adjusted from 1.1×10^{-3} to the β factor of the Multiple Greek Letter method used in the IRRAS models (8.8×10^{-2}) based on the failure of the Train A containment emergency sump outlet valve.
It was assumed that the operators would correctly follow procedures and secure the HPSI pumps before the RWST level decreases below 5%. Therefore, this was not modeled in the analysis.

An evaluation of this event,[4] prepared by the licensee, estimated that if a small-break LOCA (SLOCA) (⅜–2 in. pipe diameter) occurred, 250 min would be available to recover a recirculation flow path before the onset of core damage. Operators would initiate recirculation flow about 118 min after an SLOCA occurred. Although other CE plants consider depressurization an option, simulator exercises at San Onofre 2 showed that operating crews would not attempt to cool down and depressurize the plant for a leak size in this range. Conversely, it was not expected that small-small-break LOCAs (SSLOCAs) (<⅜ in. pipe diameter) would proceed to the recirculation phase because sufficient time was assumed to be available to cool down and depressurize the primary system. This differentiation required the IRRAS model for San Onofre 2 to be adjusted to reflect the different operator responses expected following an SSLOCA and an SLOCA. Because the importance of medium-break and large-break LOCAs calculated by the licensee using a methodology which parallels the IRRAS development was less than 1.0×10^{-6}, these larger LOCAs were not specifically modeled (i.e., the contribution to the overall importance of the event from these events is small).

Recovery from the CCW heat exchanger maintenance could begin at the time a LOCA event was recognized because the operating staff was aware of the maintenance being performed from pre-shift briefings. By similar reasoning, planning for recovery from the RWST Train B outlet valve maintenance could also begin at the time a LOCA event was recognized. The RWST Train B outlet valve was open for the injection mode and would not be required to change position for 118 min. It was assumed that this was ample time to plan and execute a desired course of action for this RWST valve.

The recovery from the train B CCW heat exchanger maintenance to repair a tube leak was expected to require 200 min.[4] This assumes 15 min for operators to recognize that an SLOCA occurred and to order the restoration of the CCW heat exchanger, 120 min for maintenance personnel to reassemble the CCW heat exchanger, 60 min for operators to realign the system valves correctly, and 5 min to restore power and start the appropriate CCW pump. These time estimates made by the licensee are conservative, yet still leave an additional 50 min before core damage would occur following an SLOCA. Performance shaping factors considered that the process would be governed by a maintenance procedure and performed under stress outside the control room by a skilled crew.[4] Based on this, the licensee estimated a 60% probability of success in restoring the CCW heat exchanger within 250 min. In addition, one HPSI pump and one residual heat removal (RHR) pump were affected by the maintenance on the CCW heat exchanger. Because the CCW system is not directly modeled by the San Onofre IRRAS model, a basic event was added to several fault trees to represent the CCW system failure probability during the ~27 h maintenance period. The new basic event (CCW-TRNB-FAIL) was added such that a failure to return the train B CCW heat exchanger to service would cause the affected pumps (HPI-MDP-FC-P019 and RHR-MDP-FC-P016) to be failed during the ~27 h CCW maintenance period. The probability of basic event CCW-TRNB-FAIL was adjusted to 0.4 for Case 2; for Case 1, the probability of this basic event occurring was zero.

Two viable options exist to recover from the Train A containment emergency sump outlet valve failing closed.[3] First, the failure of the valve could be traced to the breaker linestarter and replacement could be initiated. Secondly, it is possible to cross-connect the HPSI Train A suction to the Train B suction. In either case, 132 min (250 - 118 min) would be available before the onset of core damage following an SLOCA. Because operator training and emergency operating procedures focus attention on the correct entry into the recirculation mode, it is assumed that the operators would quickly notice the failure of the train A sump valve to open. Recognition and correction of the breaker failure were assumed to require 40 min.[4] This would allow an additional 92 min (132 - 40 min) to complete repairs before the onset of core damage. Performance shaping factors considered that the breaker repair process would not be governed by a maintenance procedure and would be performed under stress outside the control room by a skilled crew.[4] Based on this, the licensee estimated a 50% probability of success in restoring the linestarter and opening the train A sump valve within 132 min of RAS. A new basic event (HPR-SMPA-XHE-NRE) was added to the High-Pressure Recirculation (HPR) fault tree to represent the probability (0.5) that electricians would fail to repair the breaker linestarter. Recognition of the failure and cross-connecting the HPSI pump suctions were assumed to require 20 min. This action would allow an additional 112 min (132 - 20 min) to complete realignment before the onset of core damage. Performance shaping factors considered that the breaker repair process would be governed by an operating procedure and performed under stress outside the control room by a skilled crew.[4] Based on this, the licensee estimated an 80% probability of success in cross-connecting the HPSI pump suction if there were an SLOCA. A new basic event (HPR-XCONN-XHE-NR) was added to the HPR fault tree to represent the probability (0.2) that operators fail to cross-connect the HPSI pump suctions within 132 min of RAS. Because these two new events involve separate groups of plant personnel (electricians and operators), the basic events were considered to be independent. Independence was also assumed when these two new basic events were compared with the effort to restore the CCW heat exchanger, which would involve mechanics.

B.7.5 Analysis Results

Determining the overall increase in the CDP required determining the increase in the CDP for the two different cases, and then summing the results. The cases are

Case 1. 404 h, 55 min with only the Train A containment emergency sump outlet valve failed (valve HV-9305).
Case 2. 27 h, 5 min with the Train A containment emergency sump outlet valve failed (valve HV-9305) and CCW Train B unavailable.

The combined increase in the CDP from this 432-h event (i.e., the importance) is 7.2×10^{-6}. This increase is above a base-case probability for the 432-h period (the CDP) of 3.9×10^{-5} and credits the possible recovery actions discussed in Ref. 2. The resulting conditional core damage probability (CCDP) for the 432-h period in which the linestarter was failed is 4.6×10^{-5}. Most of the increase above the CDP (90%) is driven by Case 1. As expected, the common-cause failure of the containment sump valve shows up most often in the cut sets of the most significant sequences because it is driven by the initial sump valve failure. Potential recovery actions and the CCW train B failure are more conspicuous in Case 2. However, the dominant core damage sequence in both cases of this event (Sequence 2 on Fig. B.7.2) involves

- an SLOCA,
- a successful reactor trip,
- a successful initiation of emergency feedwater,
- a successful initiation of high pressure injection, and
- a failure of high pressure recirculation.

The SLOCA sequences account for ~80% of the overall increase in the CDP for this event. The next most dominant sequence among both cases involves an SSLOCA with a failure to cool down the plant before requiring HPR (SSLOCA Sequence 3). This sequence contributes 5% to the overall importance of this event.

Definitions and probabilities for selected basic events are shown in Table B.7.1. The conditional probabilities associated with the highest probability sequences are shown in Table B.7.2. Table B.7.3 lists the sequence logic associated with the sequences listed in Table B.7.2. Table B.7.4 describes the system names associated with the dominant sequences. Minimal cut sets associated with the dominant sequences are shown in Table B.7.5.

B.7.6 References

1. LER No. 361/98-003, Rev. 1, "Inoperable Valve Due to Grit in Linestarter Mechanism," March 17, 1998.

2. Letter from Dwight E. Nunn, Vice President, to U. S. Nuclear Regulatory Commission, "Response to NRC Inspection Report 98-05 Regarding Linestarters San Onofre Nuclear Generating Station, Units 2 and 3," June 22, 1998.

3. San Onofre, *Final Safety Analysis Report (Updated Version).*

4. Letter from Dwight E. Nunn, Vice President, San Onofre Nuclear Generating Station, to U. S. Nuclear Regulatory Commission, "Linestarter and AFW Supplemental Information," April 7, 1998.

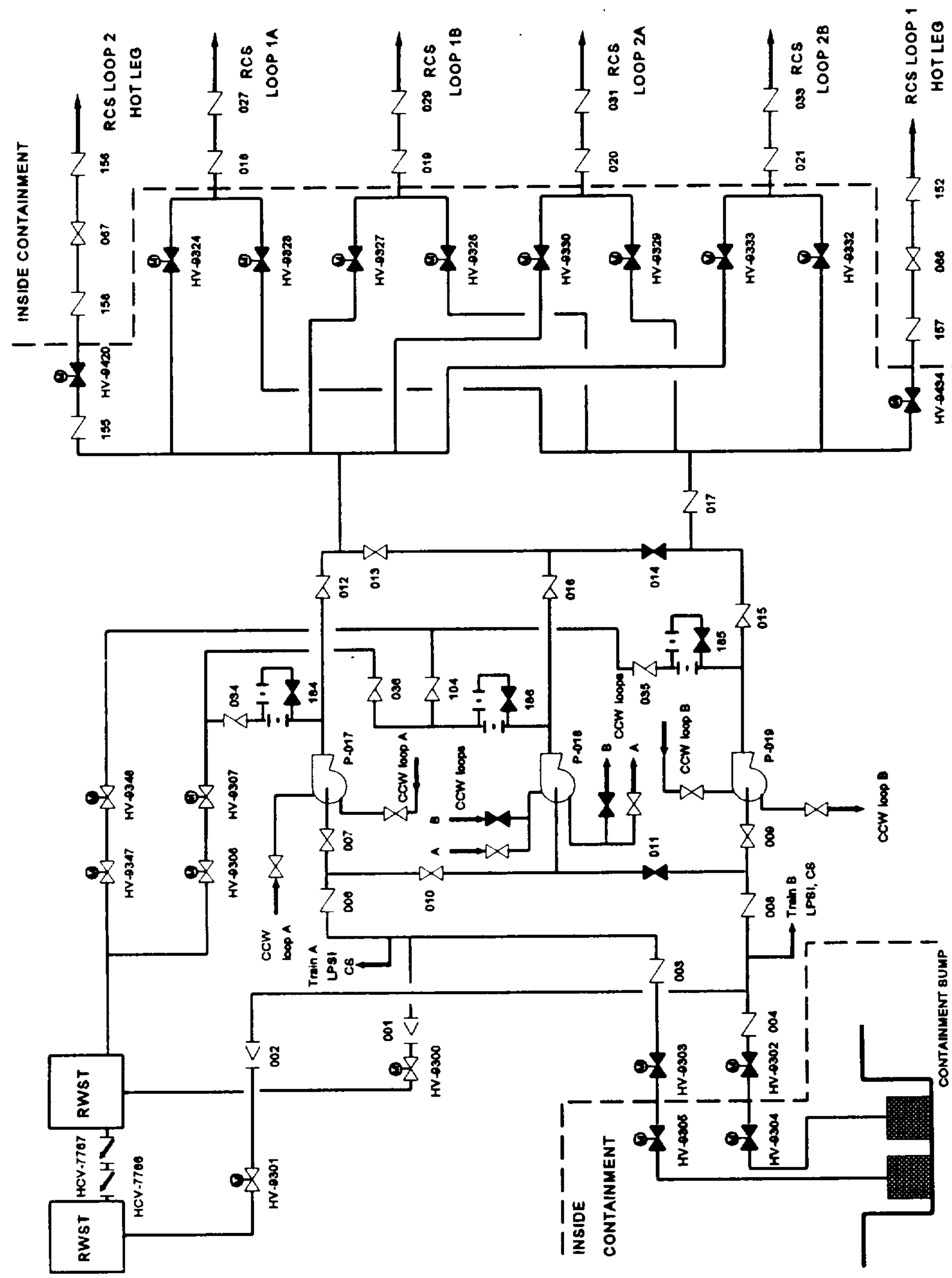

Fig. B.7.1 San Onofre High Pressure Injection System (*source: San Onofre Nuclear Generating Station, Units 2 and 3, Individual Plant Examination*). [CCW is component cooling water system, CS is containment spray, LPSI is low-pressure safety injection, RCS is reactor coolant system, and RWST is refueling water storage tank.]

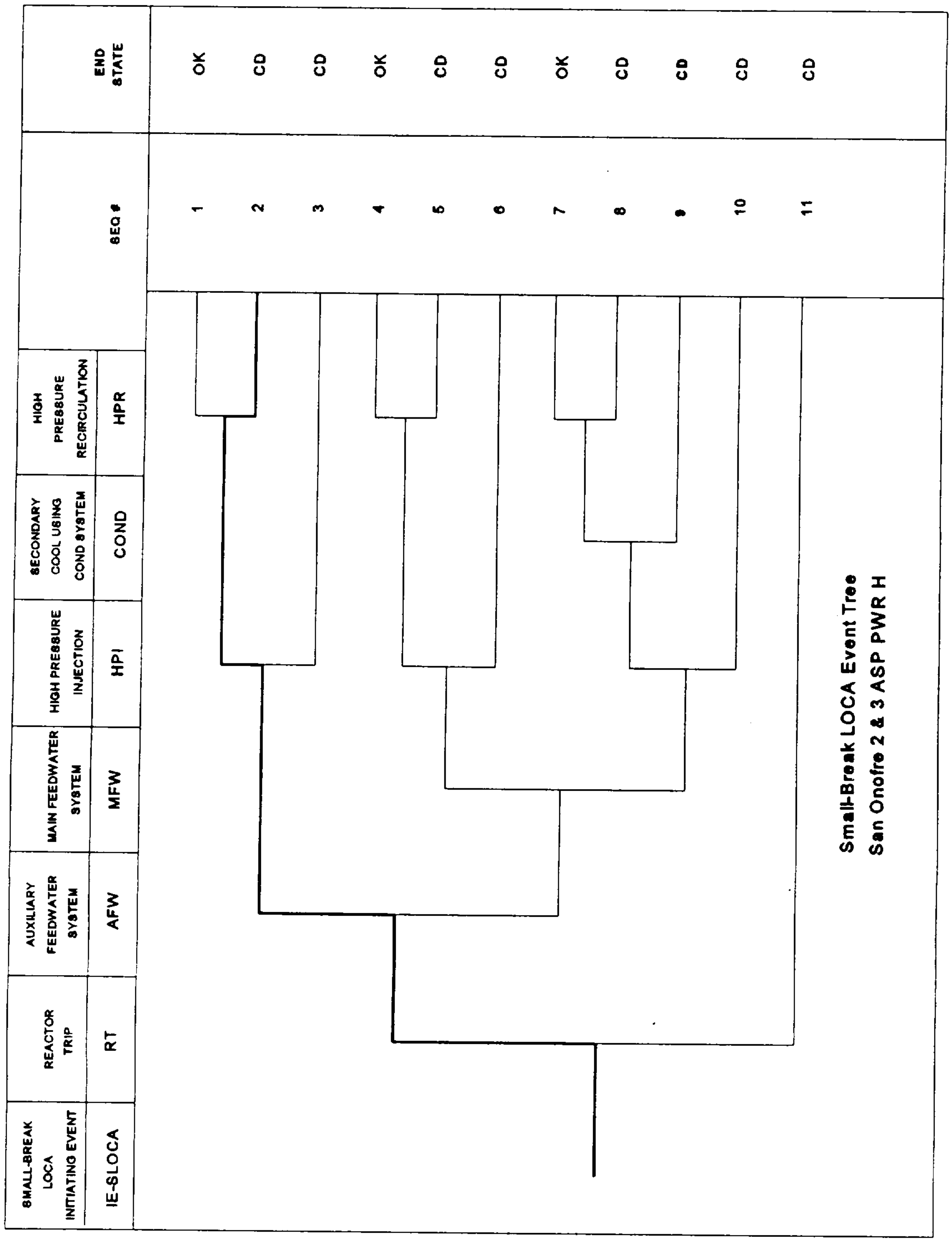

Fig. B.7.2 Dominant core damage sequence for LER No. 361/98-003.

Table B.7.1. Definitions and Probabilities for Selected Basic Events for LER No. 361/98-003

Event name	Description	Base probability	Current probability	Type	Modified for this event
IE-LOOP	Initiating Event–loss of offsite power (LOOP) (Includes the Probability of Recovering Offsite Power in the Short Term)	1.1 E-005	1.1 E-005		No
IE-SGTR	Initiating Event–Steam Generator Tube Rupture (SGTR)	2.1 E-006	2.1 E-006		No
IE-SLOCA	Initiating Event–SLOCA	1.6 E-007	1.6 E-007		Yes
IE-SSLOCA	Initiating Event–SSLOCA	2.1 E-006	2.1 E-006	NEW	Yes
IE-TRANS	Initiating Event–Transient (TRANS)	6.2 E-004	6.2 E-004		No
CCW-TRNB-FAIL	Train B CCW Heat Exchanger is not Returned to Service	0.0 E+000	4.0 E-001	NEW	Yes (Case 2)
HPR-MOV-CF-SUMP	Common-Cause Failure of Sump Isolation Motor-Operated Valves (MOVs)	1.1 E-003	8.8 E-002		Yes
HPR-SMP-FC-SUMPA	Containment Sump Train A Failure (Valve HV-9305 Stuck Closed)	6.1 E-003	1.0 E+000	TRUE	Yes
HPR-XCONN-XHE-NR	Operator Fails to Cross-Connect HPSI Suction from Train B to Train A	2.0 E-001	2.0 E-001	NEW	No
HPR-XHE-NOREC	Operator Fails to Recover the HPR System	1.0 E+000	1.0 E+000		No
HPR-XHE-XM-HLEG	Operator Fails to Initiate Hot-Leg Recirculation	1.0 E-003	1.0 E-003		No
PCS-VCF-HW	Failure of Equipment Required for Plant Cooldown	1.0 E-003	1.0 E-003		No
PCS-XHE-XM-CDOWN	Operator Fails to Initiate Cooldown	1.0 E-003	1.0 E-003		No
PPR-SRV-CO-TRAN	Safety/Relief Valves (SRVs) Open During a Transient	2.0 E-002	2.0 E-002		No
PPR-SRV-OO-1	SRV 1 Fails to Reseat	1.6 E-002	1.6 E-002		No
PPR-SRV-OO-2	SRV 2 Fails to Reseat	1.6 E-002	1.6 E-002		No

Table B.7.1. Definitions and Probabilities for Selected Basic Events for LER No. 361/98-003 (Continued)

Event name	Description	Base probability	Current probability	Type	Modified for this event
RHR-MDP-CF-AB	Common-Cause Failure of RHR Motor-Driven Pumps	5.6 E-004	5.6 E-004		No
RHR-MOV-CF-HX	Common-Cause Failure of RHR Heat Exchanger Isolation MOVs	1.1 E-003	1.1 E-003		No
RHR-MOV-CF-SUC	Common-Cause Failure of RHR Suction MOVs	1.3 E-003	1.3 E-003		No
RHR-PSF-VF-BYP	Flow Diverted From Heat Exchangers or Reactor Vessel	9.0 E-003	9.0 E-003		No
RHR-XHE-NOREC	Operator Fails to Recover the RHR System	3.4 E-001	3.4 E-001		No
RHR-XHE-XM	Operator Fails to Actuate the RHR System	1.0 E-003	1.0 E-003		No

Table B.7.2. Sequence Conditional Probabilities for LER No. 361/98-003

Event tree name	Sequence number	Conditional core damage probability (CCDP)	Core damage probability (CDP)	Importance (CCDP-CDP)	Percent contribution[c]
SLOCA	02	6.0 E-006	1.9 E-007	5.8 E-006	89.4
SSLOCA	03	4.0 E-007	1.3 E-008	3.9 E-007	6.0
SSLOCA	05	1.6 E-007	4.8 E-009	1.5 E-007	2.3
TRANS	05	7.6 E-008	2.4 E-009	7.3 E-008	1.1
Subtotal Case 1 (shown)[a]		4.3 E-005	3.7 E-005	6.5 E-006	
Subtotal Case 2[b]		3.2 E-006	2.4 E-006	7.0 E-007	
Total (all sequences)		**4.6 E-005**	**3.9 E-005**	**7.2 E-006**	

[a]Case 1 represents the increase in the CDP because of the long-term unavailability of the Train A containment emergency sump outlet valve HV-9305 (404.9 h).

[b]Case 2 represents the increase in the CDP because of maintenance being performed on the Train B CCW heat exchanger while the Train A containment emergency sump outlet valve HV-9305 was unavailable (27.1 h).

[c]Because case 1 presents the largest contribution to the total importance, the reported dominant sequences are ordered according to the importance of case 1.

Table B.7.3. Sequence Logic for Dominant Sequences for LER No. 361/98-003 (Case 1 Only)

Event tree name	Sequence number	Logic
SLOCA	02	/RT, /AFW, /HPI, HPR
SSLOCA	03	/RT,/AFW, /HPI, /COOLDOWN, RHR, HPR
SSLOCA	05	/RT,/AFW, /HPI, COOLDOWN, HPR
TRANS	05	/RT, /AFW, SRV, SRV-RES, /HPI, /COOLDOWN, RHR, HPR

Table B.7.4. System Names for LER No. 361/98-003 (Case 1 Only)

System name	Logic
AFW	No or Insufficient Auxiliary Feedwater System Flow
COOLDOWN	Reactor Coolant System Cooldown to RHR Decay Heat Removal Mode of Operation
HPI	No or Insufficient HPSI Flow
HPR	No or Insufficient HPR Flow
RHR	No or Insufficient RHR System Flow
RT	Reactor Fails to Trip
SRV	SRVs Open During a Transient
SRV-RES	SRVs Fail to Reseat

Table B.7.5. Conditional Cut Sets for Higher Probability Sequences for LER No. 361/98-003

Cut set number	Percent contribution	CCDP[a]	Cut sets[d]
SLOCA Sequence 02		6.0 E-006	
1	96.6	5.7 E-006	HPR-MOV-CF-SUMP, HPR-XHE-NOREC
2	1.1	6.5 E-008	HPR-SMP-FC-SUMPA, HPR-XHE-XM-HLEG
SSLOCA Sequence 03		4.0 E-07	
1	57.2	2.3 E-007	RHR-PSF-VF-BYP, RHR-XHE-NOREC, HPR-MOV-CF-SUMP, HPR-XHE-NOREC
2	18.7	7.4 E-008	RHR-XHE-XM, HPR-MOV-CF-SUMP, HPR-XHE-NOREC
3	8.4	3.3 E-008	RHR-MOV-CF-SUC, RHR-XHE-NOREC, HPR-MOV-CF-SUMP, HPR-XHE-NOREC
4	6.7	2.8 E-008	RHR-MOV-CF-HX, RHR-XHE-NOREC, HPR-MOV-CF-SUMP, HPR-XHE-NOREC
5	3.6	1.4 E-008	RHR-MDP-CF-AB, RHR-XHE-NOREC, HPR-MOV-CF-SUMP, HPR-XHE-NOREC
SSLOCA Sequence 05		1.6 E-007	
1	48.1	7.4 E-008	PCS-XHE-XM-CDOWN, HPR-MOV-CF-SUMP, HPR-XHE-NOREC
2	48.1	7.4 E-008	PCS-VCF-HW, HPR-MOV-CF-SUMP, HPR-XHE-NOREC
TRANS Sequence 05		7.6 E-008	
1	28.6	2.1 E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, RHR-PSF-VF-BYP, RHR-XHE-NOREC, HPR-MOV-CF-SUMP, HPR-XHE-NOREC
2	28.6	2.1 E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, RHR-PSF-VF-BYP, RHR-XHE-NOREC, HPR-MOV-CF-SUMP, HPR-XHE-NOREC
3	9.3	7.0 E-009	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, RHR-XHE-XM, HPR-MOV-CF-SUMP, HPR-XHE-NOREC
4	9.3	7.0 E-009	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, RHR-XHE-XM, HPR-MOV-CF-SUMP, HPR-XHE-NOREC
5	4.2	3.1 E-009	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, RHR-MOV-CF-SUC, RHR-XHE-NOREC, HPR-MOV-CF-SUMP, HPR-XHE-NOREC

Table B.7.5. Conditional Cut Sets for Higher Probability Sequences for LER No. 361/98-003 (continued)

Cut set number	Percent contribution	CCDP[a]	Cut sets[d]
6	4.2	3.1 E-009	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, RHR-MOV-CF-SUC, RHR-XHE-NOREC, HPR-MOV-CF-SUMP, HPR-XHE-NOREC
7	3.4	2.6 E-009	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, RHR-MOV-CF-HX, RHR-XHE-NOREC, HPR-MOV-CF-SUMP, HPR-XHE-NOREC
8	3.4	2.6 E-009	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, RHR-MOV-CF-HX, RHR-XHE-NOREC, HPR-MOV-CF-SUMP, HPR-XHE-NOREC
9	1.8	1.3 E-009	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, RHR-MDP-CF-AB, RHR-XHE-NOREC, HPR-MOV-CF-SUMP, HPR-XHE-NOREC
10	1.8	1.3 E-009	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, RHR-MDP-CF-AB, RHR-XHE-NOREC, HPR-MOV-CF-SUMP, HPR-XHE-NOREC
Subtotal Case 1[b] (shown above)		**4.2 E-005**	
Subtotal Case 2[c]		**3.2 E-006**	
Total (all sequences)		**4.6 E-005**	

[a]The change in conditional probability (importance) is determined by calculating the conditional probability for the period in which the condition existed, and subtracting the conditional probability for the same period but with plant equipment assumed to be operating nominally. The conditional probability for each cut set within a sequence is determined by multiplying the probability that the portion of the sequence that makes the precursor visible (e.g., the system with a failure is demanded) will occur during the duration of the event by the probabilities of the remaining basic events in the minimal cut set. This can be approximated by $1 - e^{-p}$, where p is determined by multiplying the expected number of initiators that occur during the duration of the event by the probabilities of the basic events in that minimal cut set. The expected number of initiators is given by λt, where λ is the frequency of the initiating event (given on a per-hour basis), and t is the duration time of the event. This approximation is conservative for precursors made visible by the initiating event. The frequencies of interest for this event are $\lambda_{TRANS} = 6.2 \times 10^{-4}$/h, $\lambda_{LOOP} = 1.1 \times 10^{-5}$/h, $\lambda_{SLOCA} = 1.6 \times 10^{-7}$/h, $\lambda_{SSLOCA} = 2.1 \times 10^{-6}$/h, and $\lambda_{SGTR} = 2.1 \times 10^{-6}$/h.

[b]Case 1 represents the increase in the CDP because of the long-term unavailability of the Train A containment emergency sump outlet valve (404.9 h).

[c]Case 2 represents the increase in the CDP because of Train B CCW heat exchanger maintenance while the Train A containment emergency sump outlet valve was unavailable (27.1 h).

[d]Basic event HPR-SMP-FC-SUMPA is a TRUE type event which is not normally included in the output of fault tree reduction programs but has been added to aid in understanding the sequences to potential core damage associated with the event.

B.8 LER No. 454/98-018

Event Description: Long-term unavailability (18 d) of an EDG

Date of Event: September 12, 1998

Plant: Byron Station, Unit 1

B.8.1 Event Summary

Byron Station, Unit 1 (Byron 1), had been in Mode 1 for 6 months following a refueling outage. During a monthly surveillance test on the 1A emergency diesel generator (EDG), the EDG tripped on a low lube oil pressure signal during the first minute of the test run. Personnel determined that the 1A EDG had been susceptible to tripping on a low lube oil pressure signal for at least 11 d until the EDG was repaired and tested satisfactorily. Because plant personnel could not precisely determine the actual failure point of the 1A EDG, for this analysis, the EDG was assumed to be unavailable for one-half of the 15-d interval between the last successful surveillance test and the point when the clogged strainers had the potential to be positively identified. Hence, this event was modeled as an 18-d (432 h) condition assessment with the 1A EDG failed. The core damage probability (CDP) at Byron 1 increased because of the increased susceptibility that would result from a loss of offsite power (LOOP) that progressed to a station blackout. The estimated increase in the CDP (i.e., the importance) for this event is 5.6×10^{-6}.

B.8.2 Event Description

On September 12, 1998, operators were starting the 1A EDG for the planned monthly surveillance test. The 1A EDG was started locally in the slow-start mode. The 1A EDG experienced a test-mode trip on an "engine lube oil pressure low" alarm during the first minute of the test run. Concurrent with this alarm were an "engine lube oil pressure low" alarm and a "turbo lube oil pressure low" alarm. An immediate inspection of the 1A EDG failed to reveal any leaks or obvious component failures; all piping components were in the correct configuration.[1]

Subsequent troubleshooting revealed that a fibrous material, consistent with that of the engine's main lube oil filter element medium, had clogged both lube oil strainers. The fibrous material was found to have covered the entire internal surface of the strainer element. An internal inspection of the lube oil filter housing unit showed that none of the filter elements had undergone a catastrophic failure. Regardless, the licensee decided to replace all 146 filter elements to perform a closer inspection of the removed elements. While replacing the filters, personnel noted that one filter element was missing its cartridge guide and many other filter elements were slightly crushed. A root-cause analysis determined that an inadequate maintenance practice was a factor in allowing a significant amount of unfiltered oil to bypass the filter elements and dislodge and transport the filter material to the lube oil strainers.[1]

B.8.3 Additional Event-Related Information

The lube oil circulating pump for each EDG runs continuously during standby conditions so that the internal engine parts remain lubricated. This facilitates a rapid start of the diesel engine. The EDGs at Byron are designed to trip on a low lube oil pressure condition when manually started or when the manual test mode switch is selected at the main control board. Although the 1A EDG should have successfully started in an emergency, the ability of the EDG to continue to perform its required function with a low lube oil pressure condition was questionable.[1]

No fibrous material was discovered in any other part of the 1A EDG lube oil system. Additionally, although no fibrous material was found in the lube oil filters on the turbocharger, the filters were replaced.[1]

The 1A EDG was returned to service on September 14, 1998. A review of the 1A EDG operating history revealed that the lube oil relief valve had lifted on September 3, 1998. The licensee subsequently determined that the relief valve had lifted because of the strainer blockage. Therefore, the 1A EDG was considered to be unavailable for at least 11 d—from September 3, 1998, until September 14, 1998, when the 1A EDG was returned to service. The licensee could not determine the actual point of failure before September 3, 1998. The last successful surveillance test on the 1A EDG was completed on August 19, 1998. Additionally, the 1A EDG operated without incident for ~12 h during a LOOP event on August 4, 1998.

The licensee verified that the 1B EDG was continually available between August 19, 1998, and September 14, 1998.[1]

B.8.4 Modeling Assumptions

After reviewing the 1A EDG records, the licensee considered the 1A EDG to be unavailable for the 11-day period between September 3, 1998, when the lube oil relief valve lifted, and September 14, 1998, when the EDG was returned to service. Because plant personnel could not precisely determine the actual failure point of the 1A EDG, for this analysis, the EDG was assumed to be unavailable for one-half of the 15-d interval between the last successful surveillance test (August 19, 1998) and the point when the clogged strainers had the potential to be positively identified (September 3, 1998). This 7.5-d window before the relief valve was noted to have lifted is in addition to the 11-d period that the 1A EDG was known to be failed. This results in a total unavailability of ~18.5 d. This event was modeled as an 18-d (432 h) condition assessment with the 1A EDG failed.

If the lube oil relief valve had not lifted and provided a reference failure point, the 1A EDG would have been presumed to be unavailable for half of the 26-d period since the last successful surveillance. A 13-d EDG unavailability was analyzed as a sensitivity study.

Because the ability to cross-tie the A and B emergency buses between Byron 1 and 2 exists, the EDGs from Unit 2 were added to the Integrated Reliability and Risk Analysis System (IRRAS) model for Unit 1. The probabilities that either of the opposite unit EDGs fails to start and run (basic events EPS-DGN-FC-2A and EPS-DGN-FC-2B) were set to the base probability of the Unit 1 EDGs (3.8×10^{-2}). The Byron/Braidwood Updated Final Safety Analysis Report indicates that a single EDG can provide sufficient ac power to safely shut down both units in the event of a station blackout.[2] However, because operators must manually cross-tie the emergency buses between units, a basic event was added to reflect the probability that the operator fails to start and load the alternate EDG (basic event EPS-XHE-XM-OU). The probability for basic event EPS-XHE-XM-OU was set to 8.0×10^{-2} based on a human error analysis provided in the Byron individual plant examination (IPE).[3]

The common-cause failure probability of the emergency power system for the base case was revised to reflect the availability of four EDGs (two from each unit) and was developed using the data distributions contained in NUREG/CR-5497, *Common-Cause Failure Parameter Estimations* (Ref. 4, Table 5-9: alpha factor distribution summary – fail to start, CCCG = 4, $\alpha_{4S} = 0.0116$; and Table 5-12: alpha factor distribution summary – fail to run, CCCG = 4, $\alpha_{4R} = 0.0146$). Because α_4 is equivalent to the $\beta\gamma\delta$ factor of the multiple Greek letter (MGL) method used in the IRRAS models, the base case common-cause failure probability for four EDGs (basic event EPS-DGN-CF-ALL) is 4.6×10^{-4}.

LER No. 454/98-018 (p. 3) states that "other factors that contributed to the event were determined to be an inadequate maintenance procedure and inadequate maintenance practice." Both causes would transcend a single maintenance crew and the maintenance done on the 1A EDG was not presented as unique to just that EDG. Furthermore, crushed filter media degrades at variable rates. Therefore, the fact that this maintenance is not done simultaneously on multiple EDGs does not preclude this failure mechanism from simultaneously affecting more than one EDG. The common-cause failure probability for the EDGs is composed of failure to start and failure to run. The portion of the base case EDG common-cause failure probability for an engine to start was not altered because the low lube oil pressure trip is not in effect following an emergency start of an EDG. However, the portion of the base case EDG common-cause failure probability for failure to run for the mission time was adjusted based on the failure mechanism described. Because data specific to common-cause failures of the lube oil system was not available, aggregate EDG common-cause failure data were used in this analysis. However, it is not expected that this use of data introduces a significant error in the resulting estimate. Based on the failure of the 1A EDG with common-cause failure potential, basic event EPS-DGN-CF-ALL was adjusted for this event from 4.6×10^{-4} to 1.5×10^{2} based on the MGL method (Ref. 4, Table 5-5 Summary of MGL Parameter Estimations – Fail to Run).

In the SBO sequences, the probabilities of a reactor coolant pump (RCP) seal loss-of-coolant accident (LOCA) and of failing to recover ac power at various points in time are calculated using a convolution approach that recognizes that all probabilities are a function of time. A Weibull distribution is used to predict the LOOP-related parameters applicable for Byron as defined in ORNL/NRC/LTR-89/11 (Ref. 5). Probabilities associated with the failure to recover ac power and the potential for an RCP seal LOCA are calculated given that ac power was not restored at specific points in time. Additionally, the probability for the operators' failure to restore emergency power is based on the assumption that the median repair time for an EDG is 4 h, as developed in NUREG-1032 (Ref. 6). The ac power non-recovery probabilities (typically valued at 0.8) in the Byron Integrated Reliability and Risk Analysis System (IRRAS) model are conditional probability values. These ac power non-recovery basic events represent the probability that an ac power source is not reestablished before core damage occurs *given* that power has not been restored at a particular reference point (i.e., battery failure or an RCP seal LOCA). Accounting for the conditional attributes of the ac power recovery basic events in the Byron IRRAS model, the 2-h and 8-h ac power non-recovery probability values can be approximated as 0.42 and 0.02, respectively, when taken over the entire time interval. These values are not significantly different from the historically generated values used in the Byron PSA (0.32 and 0.03, respectively).

B.8.5 Analysis Results

The increase in the CDP (i.e., the importance) as the result of an 18-d failure of the 1A EDG with common-cause failure-to-run implications for this event is estimated to be 5.6×10^{-6}. The base probability over the same 18-d period (the CDP) for all sequences is 8.0×10^{-7}, resulting in a conditional core damage probability (CCDP) of 6.4×10^{-6}. As expected, station blackout (SBO) sequences dominate. The dominant core damage sequence for this event (Sequence 18 on Fig. B.8.1 and Sequence 18-9 on Fig. B.8.2) involves the following events:

- a LOOP,
- a successful reactor trip,
- a failure of the emergency power system,
- a successful initiation of auxiliary feedwater (AFW),
- successful control of reactor coolant system pressure such that the power-operated relief valves (PORVs) remain closed,
- a failure of the RCP seals, and
- a failure of the operators to restore ac power before core damage.

This sequence accounts for 24% of the total contribution to the increase in the CDP. A second SBO sequence where the RCP seals do not fail, but the operators fail to restore ac power before the batteries are depleted (Sequence 18-2), accounts for an additional 21% of the increase in the CDP. A third SBO sequence where the PORVs fail open accounts for 20% of the increase in the CDP (Sequence 18-20).

A sensitivity study on the length of time that the 1A EDG was unavailable was performed assuming the 1A EDG to be unavailable for just half of the 26-d surveillance period. Such a 13-d unavailability results in a calculated importance of 4.0×10^{-6}. This is similar to the importance calculated for the assumed 18-d unavailability. Therefore, the length of the unavailability does not significantly affect the importance calculation.

Definitions and probabilities for selected basic events are shown in Table B.8.1. The conditional probabilities associated with the highest probability sequences are shown in Table B.8.2. Table B.8.3 lists the sequence logic associated with the sequences listed in Table B.8.2. Table B.8.4 describes the system names associated with the dominant sequences. Minimal cut sets associated with the dominant sequences are shown in Table B.8.5.

B.8.6 References

1. LER 454/98-018, Rev. 0, "Inoperable Unit 1 Diesel Generator Due to Low Lube Oil Pressure Condition," October 9, 1998.

2. *ComEd Byron and Braidwood Stations Updated Final safety Analysis Report.*

3. *ComEd Byron and Braidwood Stations Individual Plant Examinations*, March 1997.

4. Marshall, Rasmuson, and Mosleh, *Common-Cause Failure Parameter Estimations*, NUREG/CR-5497, October 1998.

5. *Revised LOOP Recovery and PWR Seal LOCA Models*, ORNL/NRC/LTR-89/11, August 1989.

6. P. W. Baranowsky, *Evaluation of Station Blackout Accidents at Nuclear Power Plants*, NUREG-1032, U.S. Nuclear Regulatory Commission, June 1988.

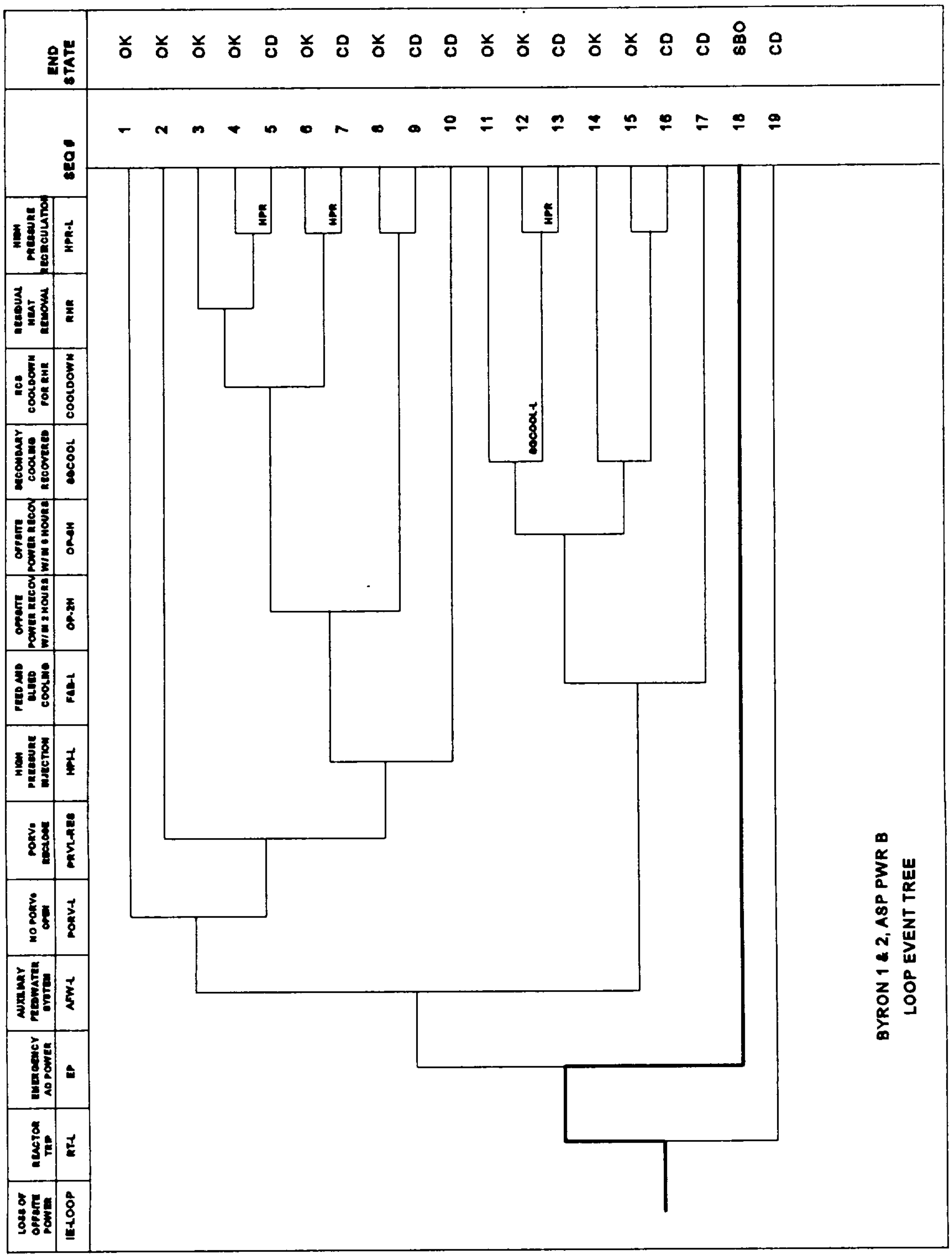

Fig. B.8.1. Dominant core damage sequence for LER No. 454/98-018.

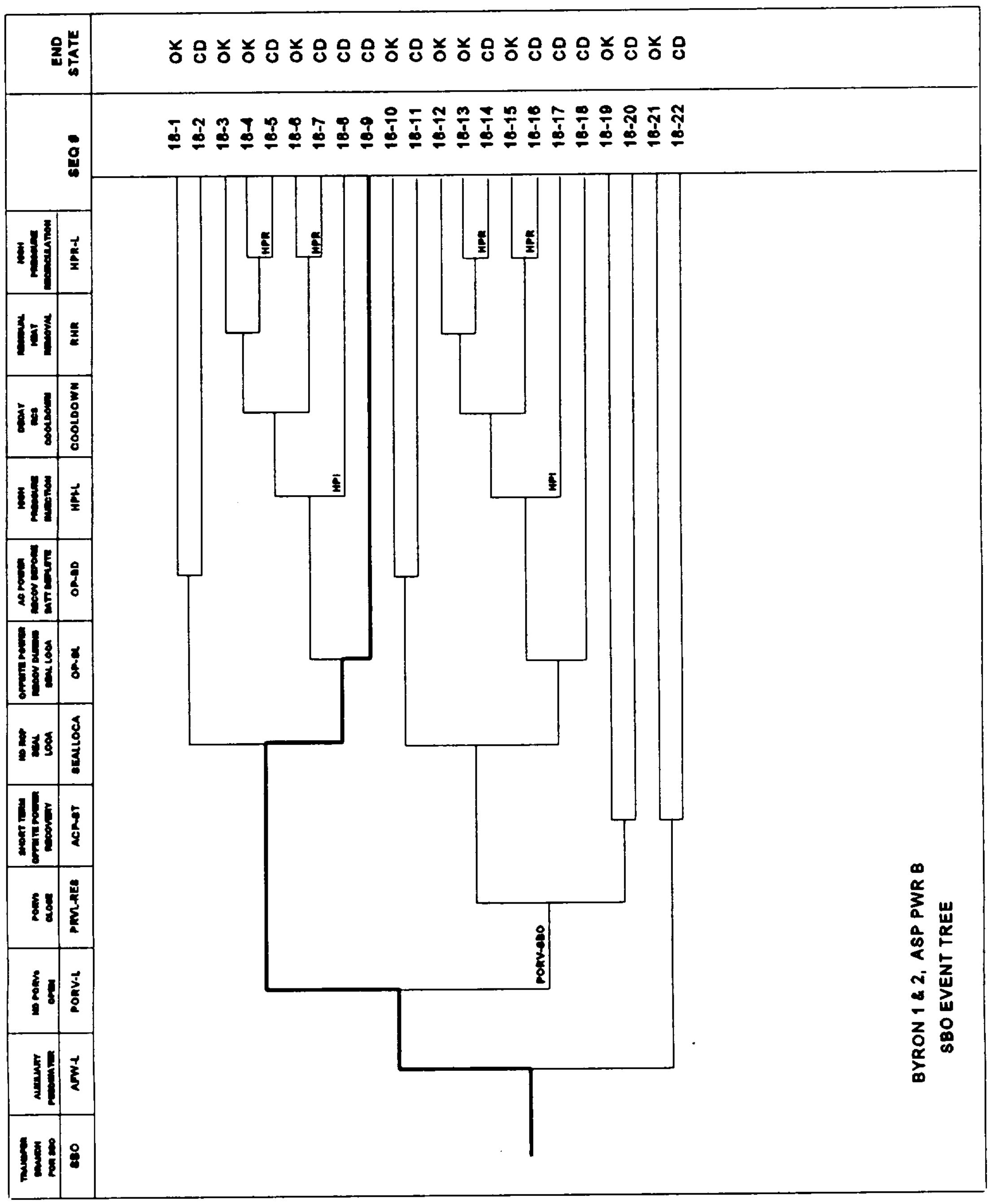

Fig. B.8.2. Dominant core damage sequence for LER No. 454/98-018.

Table B.8.1. Definitions and Probabilities for Selected Basic Events for LER No. 454/98-018

Event name	Description	Base probability	Current probability	Type	Modified for this event
IE-LOOP	Initiating Event–loss of offsite power (LOOP) (excludes the Probability of Recovering Offsite Power in the Short Term)	1.6 E-005	1.6 E-005		No
IE-SGTR	Initiating Event–Steam Generator Tube Rupture	1.6 E-006	1.6 E-006		No
IE-SLOCA	Initiating Event–Small-Break loss-of-coolant accident (LOCA)	2.3 E-006	2.3 E-006		No
IE-TRANS	Initiating Event–Transient	2.5 E-004	2.5 E-004		No
AFW-EDP-FC-1B	Auxiliary Feedwater (AFW) Diesel-Driven Pump Fails	2.0 E-002	2.0 E-002		No
AFW-MDP-FC-1A	AFW Motor-Driven Pump Fails	4.0 E-003	4.0 E-003		No
AFW-PMP-CF-ALL	Common-Cause Failure of AFW Pumps	2.1 E-004	2.1 E-004		No
EPS-DGN-CF-ALL	Common-Cause Failure of emergency diesel generators (EDGs)	4.6 E-004	1.5 E-002		Yes
EPS-DGN-FC-1A	EDG 1A Fails	3.8 E-002	1.0 E+000	TRUE	Yes
EPS-DGN-FC-1B	EDG 1B Fails	3.8 E-002	3.8 E-002		No
EPS-XHE-XM-OU	Operator Fails to Cross-Connect ESF Bus Without ac Power to Opposite Unit	8.0 E-002	8.0 E-002	NEW	No
HPI-MDP-CF-ALL	Common-Cause Failure of High-Pressure Injection (HPI) Pumps	7.8 E-004	7.8 E-004		No
HPI-MDP-FC-1B	HPI Motor-Driven Pump Fails	3.8 E-003	3.8 E-003		No
HPI-XHE-XM-FBL	Operator Fails to Initiate Feed-and-Bleed Cooling	1.0 E-002	1.0 E-002		No
LOOP-17-NREC	LOOP Sequence 17 Nonrecovery Probability – Failure to Recover AFW-L (0.26) and Feed-and-Bleed Cooling (0.8)	2.2 E-001	2.2 E-001		No

Table B.8.1. Definitions and Probabilities for Selected Basic Events for LER No. 454/98-018 (Continued)

Event name	Description	Base probability	Current probability	Type	Modified for this event
LOOP-18-02-NREC	LOOP Sequence 18-02 Nonrecovery Probability – Failure to Recover Electric Power (EP)	8.0 E-001	8.0 E-001		No
LOOP-18-11-NREC	LOOP Sequence 18-11 Nonrecovery Probability – Failure to Recover EP	8.0 E-001	8.0 E-001		No
LOOP-18-18-NREC	LOOP Sequence 18-18 Nonrecovery Probability – Failure to Recover EP	8.0 E-001	8.0 E-001		No
LOOP-18-20-NREC	LOOP Sequence 18-20 Nonrecovery Probability – Failure to Recover EP	8.0 E-001	8.0 E-001		No
LOOP-18-22-NREC	LOOP Sequence 18-22 Nonrecovery Probability – Failure to Recover EP (0.8) and AFW-L (0.34)	2.7 E-001	2.7 E-001		No
OEP-XHE-NOREC-BD	Operator Fails to Recover ac Power Before Battery Depletion	2.0 E-002	2.0 E-002		No
OEP-XHE-NOREC-SL	Operator Fails to Recover ac Power Before Core Damage Results From a Seal LOCA	6.3 E-001	6.3 E-001		No
OEP-XHE-NOREC-ST	Operator Fails to Recover ac Power in the Short Term	5.3 E-001	5.3 E-001		No
PPR-SRV-CC-PRV1	PORV 1 Fails to Open on Demand	6.3 E-003	6.3 E-003		No
PPR-SRV-CC-PRV2	PORV 2 Fails to Open on Demand	6.3 E-003	6.3 E-003		No
PPR-SRV-CO-SBO	Safety/Relief Valves Open During a Station Blackout (SBO)	3.7 E-001	3.7 E-001		No
PPR-SRV-OO-PRV1	PORV 1 Fails to Reseat	3.0 E-002	3.0 E-002		No
PPR-SRV-OO-PRV2	PORV 2 Fails to Reseat	3.0 E-002	3.0 E-002		No
RCS-MDP-LK-SEALS	Reactor Coolant Pump (RCP) Seals Fail without Cooling and Injection	3.5 E-002	3.5 E-002		No

Table B.8.2. Sequence Conditional Probabilities for LER No. 454/98-018

Event tree name	Sequence number	Conditional core damage probability (CCDP)	Core damage probability (CDP)	Importance (CCDP-CDP)	Percent contribution[a]
LOOP	18-09	1.4 E-006	4.4 E-008	1.3 E-006	24.1
LOOP	18-02	1.2 E-006	3.9 E-008	1.2 E-006	21.1
LOOP	18-20	1.2 E-006	3.8 E-008	1.1 E-006	20.4
LOOP	18-18	8.1 E-007	2.6 E-008	7.9 E-007	14.2
LOOP	18-11	7.1 E-007	2.3 E-008	6.9 E-007	12.4
LOOP	18-22	3.6 E-007	1.2 E-008	3.5 E-007	6.3
LOOP	17	7.8 E-008	1.4 E-008	6.4 E-008	1.1
Total (all sequences)		**6.4 E-006**	**8.0 E-007**	**5.6 E-006**	

[a]Percent contribution to the total importance.

Table B.8.3. Sequence Logic for Dominant Sequences for LER No. 454/98-018

Event tree name	Sequence number	Logic
LOOP	18-09	/RT-L, EP, /AFW-L, /PORV-SBO, SEALLOCA, OP-SL
LOOP	18-02	/RT-L, EP, /AFW-L, /PORV-SBO, /SEALLOCA, OP-BD
LOOP	18-20	/RT-L, EP, /AFW-L, PORV-SBO, PRVL-RES, ACP-ST
LOOP	18-18	/RT-L, EP, /AFW-L, PORV-SBO, /PRVL-RES, SEALLOCA, OP-SL
LOOP	18-11	/RT-L, EP, /AFW-L, PORV-SBO, /PRVL-RES, /SEALLOCA, OP-BD
LOOP	18-22	/RT-L, EP, AFW-L, ACP-ST
LOOP	17	/RT-L, /EP, AFW-L, F&B-L

Table B.8.4. System Names for LER No. 454/98-018

System name	Logic
ACP-ST	Offsite Power Recovered in Short Term
AFW-L	No or Insufficient AFW System Flow During LOOP
EP	Emergency Power System Fails
F&B-L	Failure to Provide Feed and Bleed Cooling
OP-BD	Operator Fails to Recover ac Power Before Battery Depletion
OP-SL	Operator Fails to Recover ac Power Before Core Damage Results Following an RCP Seal LOCA
PORV-SBO	PORVs Open During an SBO
PRVL-RES	PORVs and Block Valves Fail to Reclose
RT-L	Reactor Fails to Trip During a LOOP
SEALLOCA	RCP Seals Fail During a LOOP

Table B.8.5. Conditional Cut Sets for Higher Probability Sequences for LER No. 454/98-018

Cut set number	Percent contribution	CCDP[a]	Cut sets[b]
LOOP Sequence 18-09		1.4 E-006	
1	83.1	1.1 E-006	EPS-DGN-CF-ALL, /PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL, LOOP-18-09-NREC
2	16.8	2.3 E-007	EPS-DGN-FC-1A, EPS-DGN-FC-1B, EPS-XHE-XM-OU, /PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL, LOOP-18-09-NREC
LOOP Sequence 18-02		1.2 E-006	
1	83.1	1.0 E-006	EPS-DGN-CF-ALL, /PPR-SRV-CO-SBO, /RCS-MDP-LK-SEALS, OEP-XHE-NOREC-BD, LOOP-18-02-NREC
2	16.8	2.0 E-007	EPS-DGN-FC-1A, EPS-DGN-FC-1B, EPS-XHE-XM-OU, /PPR-SRV-CO-SBO, /RCS-MDP-LK-SEALS, OEP-XHE-NOREC-BD, LOOP-18-02-NREC
LOOP Sequence 18-20		1.2 E-006	
1	41.6	4.9 E-007	EPS-DGN-CF-ALL, PPR-SRV-CO-SBO, PPR-SRV-OO-PRV1, OEP-XHE-NOREC-ST, LOOP-18-20-NREC
2	41.6	4.9 E-007	EPS-DGN-CF-ALL, PPR-SRV-CO-SBO, PPR-SRV-OO-PRV2, OEP-XHE-NOREC-ST, LOOP-18-20-NREC
3	8.4	9.9 E-008	EPS-DGN-FC-1A, EPS-DGN-FC-1B, EPS-XHE-XM-OU, PPR-SRV-CO-SBO, PPR-SRV-OO-PRV2, OEP-XHE-NOREC-ST, LOOP-18-20-NREC
4	8.4	9.9 E-008	EPS-DGN-FC-1A, EPS-DGN-FC-1B, EPS-XHE-XM-OU, PPR-SRV-CO-SBO, PPR-SRV-OO-PRV2, OEP-XHE-NOREC-ST, LOOP-18-20-NREC
LOOP Sequence 18-18		8.1 E-007	
1	83.1	6.7 E-007	EPS-DGN-CF-ALL, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL, LOOP-18-18-NREC
2	16.8	1.4 E-007	EPS-DGN-FC-1A, EPS-DGN-FC-1B, EPS-XHE-XM-OU, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL, LOOP-18-18-NREC

Table B.8.5. Conditional Cut Sets for Higher Probability Sequences for LER No. 454/98-018 (continued)

Cut set number	Percent contribution	CCDP[a]	Cut sets[b]
LOOP Sequence 18-11		7.1 E-007	
1	83.1	5.9 E-007	EPS-DGN-CF-ALL, PPR-SRV-CO-SBO, /RCS-MDP-LK-SEALS, OEP-XHE-NOREC-BD, LOOP-18-11-NREC
2	16.8	1.2 E-007	EPS-DGN-FC-1A, EPS-DGN-FC-1B, EPS-XHE-XM-OU, PPR-SRV-CO-SBO, /RCS-MDP-LK-SEALS, OEP-XHE-NOREC-BD, LOOP-18-11-NREC
LOOP Sequence 18-22		3.6 E-007	
1	82.1	3.0 E-007	EPS-DGN-CF-ALL, AFW-EDP-FC-1B, OEP-XHE-NOREC-ST, LOOP-18-22-NREC
2	16.6	6.0 E-008	EPS-DGN-FC-1A, EPS-DGN-FC-1B, EPS-XHE-XM-OU, AFW-EDP-FC-1B, OEP-XHE-NOREC-ST, LOOP-18-22-NREC
LOOP Sequence 17		7.8 E-008	
1	31.1	2.4 E-008	EPS-DGN-FC-1A, EPS-XHE-XM-OU, AFW-EDP-FC-1B, HPI-XHE-XM-FBL, LOOP-17-NREC
2	19.6	1.5 E-008	EPS-DGN-FC-1A, EPS-XHE-XM-OU, AFW-EDP-FC-1B, PPR-SRV-CC-PRV1, LOOP-17-NREC
3	19.6	1.5 E-008	EPS-DGN-FC-1A, EPS-XHE-XM-OU, AFW-EDP-FC-1B, PPR-SRV-CC-PRV2, LOOP-17-NREC
4	11.8	9.2 E-009	EPS-DGN-FC-1A, EPS-XHE-XM-OU, AFW-EDP-FC-1B, HPI-MDP-FC-1B, LOOP-17-NREC
5	4.1	3.2 E-009	AFW-PMP-CF-ALL, HPI-XHE-XM-FBL, LOOP-17-NREC
6	2.6	2.0 E-009	AFW-PMP-CF-ALL, PPR-SRV-CC-PRV1, LOOP-17-NREC
7	2.6	2.0 E-009	AFW-PMP-CF-ALL, PPR-SRV-CC-PRV2, LOOP-17-NREC
8	2.4	1.9 E-009	EPS-DGN-FC-1A, EPS-XHE-XM-OU, AFW-EDP-FC-1B, HPI-MDP-CF-ALL, LOOP-17-NREC
9	1.6	1.2 E-009	AFW-EDP-FC-1B, AFW-MDP-FC-1A, HPI-XHE-XM-FBL, LOOP-17-NREC
Total (all sequences)		**6.4 E-006**	

[a]The change in conditional probability (importance) is determined by calculating the conditional probability for the period in which the condition existed and subtracting the conditional probability for the same period but with plant equipment assumed to be operating nominally. The conditional probability for each cut set within a sequence is determined by multiplying the probability that the portion of the sequence that makes the precursor visible (e.g., the system with a failure is demanded) will occur during the duration of the event by the probabilities of the remaining basic events in the minimal cut set. This can be approximated by $1 - e^{-p}$, where p is determined by multiplying the expected number of initiators that occur during the duration of the event by the probabilities of the basic events in that minimal cut set. The expected number of initiators is given by λt, where λ is the frequency of the initiating event (given on a per-hour basis) and t is the duration time of the event. This approximation is conservative for precursors made visible by the initiating event. The frequencies of interest for this event are $\lambda_{TRANS} = 2.5 \times 10^{-4}$/h, $\lambda_{LOOP} = 1.6 \times 10^{-5}$/h, $\lambda_{SLOCA} = 2.3 \times 10^{-6}$/h, and $\lambda_{SGTR} = 1.6 \times 10^{-6}$/h. The duration time for this event is 432 h.

[b]Basic event, EPS-DGN-FC-1A, is a TRUE type event that is not normally included in the output of fault tree reduction programs but has been added to aid in understanding the sequences to potential core damage associated with the event.

Appendix C:

Shutdown Precursors for 1998

C.1 Shutdown Precursors

C.1.1 Accident Sequence Precursor Program Event Analyses for 1998

This appendix documents 1998 operational events selected as precursors that are analyzed with the plant in a shutdown condition.

Licensee event reports (LERs) and other event documentation describing operational events at commercial nuclear power plants were reviewed for potential precursors if

1. the LER was identified as requiring review based on a computerized search of the Sequence Coding and Search System data base maintained at the Nuclear Operations Analysis Center (NOAC), or

2. the LER or other event documentation was identified as requiring review by the Nuclear Regulatory Commission (NRC) Office for Analysis and Evaluation of Operational Data.

Details of the precursor review, analysis, and documentation process are provided in Appendix A of this report.

C.1.2 Shutdown Precursors Identified

No shutdown precursor events were identified among the 1998 events reviewed at the NOAC. Events were identified as shutdown precursors if they met the following selection criteria:

1. the event involved a core damage initiator such as a loss of shutdown cooling, loss of reactor vessel inventory, loss of offsite power, or a loss-of-coolant accident, and

2. the initiator could only have occurred with the plant in a shutdown condition, and

3. the conditional core damage probability estimated for the event was at least 10^{-6}.

Appendix D:

Potentially Significant Events Considered Impractical to Analyze

D.1 Potentially Significant Events Considered Impractical to Analyze

None of the licensee event reports (LERs) for 1998 were identified as potentially significant but impractical to analyze. It is believed that events considered impractical are capable of impacting core damage sequences. However, the events usually involve component degradations in which the extent of the degradation could not be determined or the impact of the degradation on plant response could not be ascertained.

Appendix E:

Containment-Related Events

E.1 Containment-Related Events

One reactor plant operational event for 1998 was selected as a containment-related event. Such events involve unavailability of containment function, containment isolation, containment cooling, containment spray, or postaccident hydrogen control. Containment-related events are not currently considered precursor events under the Accident Sequence Precursor (ASP) Program; the ASP Program is currently developing containment-related event models. The potential for increased exposure to the public justifies their inclusion in the report. The events identified for 1998 are shown in Table E.1.

A summary, event description, and any additional event-related information are provided for these events.

Table E.1 Index of Containment-Related Events

Event number	Plant	Event description	Page
LER 336/98-001	Millstone 2	Feedwater valves may not be able to close fully on an isolation signal	E.2-1

E.2 LER No. 336/98-011

Event Description: Feedwater valves may not be able to close fully on an isolation signal

Date of Event: May 19, 1998

Plant: Millstone 2

E.2.1 Event Summary

During a forced outage in September 1993, personnel modified both the feedwater pump discharge and blocking valves by removing the motor brakes on the valve actuator motors. Following this change, maintenance personnel failed to verify adequate valve closure. On May 19, 1998, wear marks on the isolation valve disc seating surfaces indicated that the valves may not have closed fully when feedwater system flow existed. Under these conditions, if a main steam line break (MSLB) were to occur inside containment, the result would be higher containment pressures than analyzed for accident conditions.

E.2.2 Event Description

During the September 1993, forced outage, personnel modified two feedwater pump discharge valves (2-FW-38A and -38B) and two feedwater block valves (2-FW-42A and -42B) by removing the motor brakes. The motor-operated feedwater discharge valves are located between the turbine-driven main feedwater pumps and the high-pressure heaters. The feedwater block valves are located between the high-pressure heaters and the main feedwater regulating valves. These valves regulate feedwater flow into the steam generators.

The motor brakes were removed in response to NRC Information Notice 93-98, "Motor Brakes on Valve Actuator Motors." The purpose of a motor brakes is to minimize the inertial loads arising during valve closure after the torque switch has tripped. Because of the fast closure speed of the valves, the valve motors could not be deenergized by the torque switch. This is because the large inertia of these 18-in valves would drive the valve disc into the seat and result in valve damage. Therefore, modifying the design allowed the motor to be deenergized by the "close" limit switch and allowed the valve to close completely from inertia.

E.2.3 Basis for Selection as a Containment-Related Event

During an inspection of the internals of the feedwater pump discharge valves, 2-FW-38 A & B, and feedwater block valves, 2-FW-42 A & B, personnel determined that the valves had been closing completely under no-flow conditions. An inspection of wear marks on the disc's seating surfaces showed that the valves may have failed to achieve adequate closure to ensure flow shutoff [by ~0.5–1.3 cm (0.2–0.5 in)], with maximum differential pressure.

E.2.4 Factors of Interest

Following an MSLB, the main feedwater system is isolated by a main steam isolation signal (MSIS) to stop feedwater flow into the faulted steam generator. This reduces the mass flow out of the faulted steam generator into containment. The MSIS trips both feedwater pumps, closes both feedwater check valves, closes both feedwater regulating valves, closes both feedwater pump discharge bypass valves, closes both feedwater pump discharge valves (2-FW-38A and -38B), and closes both feedwater block valves (2-FW-42A and -42B). If the feedwater regulating valves fail to close, the feedwater pump discharge and feedwater blocking valves would be forced to close against the pressure resulting from substantial feedwater system flow. Because full valve closure could not be assured, the additional feedwater entering (and exiting) the faulted steam generator would result in a higher containment pressure than was analyzed for an MSLB accident.

E.2.5 References

1. LER 336/98-011, Rev. 0, "Feedwater Valves Not Able to Fully Close on Isolation Signal," June 18, 1998.

2. NRC Information Notice 93-98, "Motor Brakes on Valve Actuator Motors," December 20, 1993.

Appendix F:

"Interesting" Events

F.1 "Interesting" Events

The two reactor plant operational events for 1998 selected as "interesting" events are documented in this section. "Interesting" events are not normally precursors as defined by the Accident Sequence Precursor Program; however, they provide insight into unusual failure modes with the potential to compromise continued core cooling. The events identified for 1998 are shown in Table F.1.

A summary, event description, and any additional event-related information are provided for these events.

Table F.1 Index of "Interesting" Events

Event number	Plant	Event description	Page
LER 266/98-002	Point Beach 1	Loss of the station auxiliary transformer while at power	F.2-1
LER 397/98-011	WNP 2	ECCS pump room flooding because of a fire protection system pipe break	F.3-1

F.2 LER No. 266/98-002

Event Description: Loss of the station auxiliary transformer while at power

Date of Event: January 8, 1998

Plant: Point Beach 1

F.2.1 Event Summary

With Unit 1 at 98% power, the high voltage station auxiliary transformer, 1X03, automatically isolated when the breakers on the low voltage side and the high voltage side of the transformer opened. An automatic fast transfer to the Unit 2 high voltage station auxiliary transformer, 2X03, failed to occur. This resulted in a loss of normal power to the Unit 1 4160-V supply buses 1A03 and 1A04 and safeguards buses 1A05 and 1A06. The emergency diesel generators (EDGs) automatically started and supplied power to Unit 1 safeguards buses 1A05 and 1A06. The Unit 1 main generator continued supplying electric power to the non-vital loads via the unit auxiliary transformer, 1X02. The reactor remained at power. The operating crew did not initially identify that Technical Specifications required that Unit 1 be shut down under these conditions. However, the conditions requiring that the unit be shut down were corrected within the time allowed by the Technical Specifications.

F.2.2 Event Description

At 1904 on January 8, 1998, Point Beach 1 was operating at 98% power when a ground fault occurred on the low voltage side bus duct of the high voltage station auxiliary transformer, 1X03. Breakers on the low- and high-voltage sides of transformer 1X03 opened to isolate the fault. Condensation internal to the buses and the long-term degradation of the insulation in the low-voltage side bus duct caused the ground fault. Because the circuit breaker for the heater used to keep the bus duct dry would not remain closed, the breaker was left open. Personnel then submitted a maintenance request for the breaker—this was in August 1996. The associated work order was classified as "minor maintenance" (i.e., low significance and low priority) and work had not started before the January 1998 event.

A 13.8-kV automatic bus transfer should have closed breaker H52-31 to restore power to the Unit 1 13.8-kV bus from the Unit 2 high voltage station auxiliary transformer, 2X03. However, the control circuitry for H52-31 was improperly wired. This prevented any fast transfer from occurring. Breaker H52-21 should have also closed allowing the on-site gas turbine generator (G05) to provide electric power to the auxiliaries. Similar to breaker H52-31, breaker H52-21 was also improperly wired. The improper wiring occurred when personnel moved the control switches for these two breakers during the EDG addition project in 1994. The type of control switch was changed when the breakers were moved; a design review failed to identify any differences between the old switches and the new switches. Post-modification testing did not test the automatic bus transfer circuitry. In addition, periodic testing of the 13.8-kV automatic bus transfer had not been performed.

The Unit 1 4160-V supply buses 1A03 and 1A04 and the Unit 1 safeguard buses 1A05 and 1A06 lost power. The loss of power to 1A05 and 1A06 initiated an engineered safety features (ESF) actuation on degraded voltage, which started EDGs G01, G03, and G04. EDG G02 did not start because it was out of service for maintenance. EDGs G01 and G03 automatically aligned to safeguards buses 1A05 and 1A06, respectively. EDG G04 was aligned to automatically provide power to Unit 2 safeguards bus 2A06, but the EDG did not load because Unit 2 did not experience a loss of offsite power (i.e., bus 2A06 remained powered). The service water and component cooling water pumps restarted automatically. The Unit 1 auxiliaries, including the reactor coolant pumps, the main feedwater pumps, the circulating water pumps, and the condensate pumps remained powered from the Unit 1 generator via the unit auxiliary transformer, 1X02. As a result, Unit 1 remained at 98% power.

At 2158, personnel aligned the gas turbine generator (G05) to provide electric power to low voltage auxiliary transformer 1X04. This transformer provides power to the 4160-V supply buses 1A03 and 1A04. Operators also aligned the gas-turbine generator to operate in parallel with offsite power via the high voltage station auxiliary transformer 2X03. Technical specifications limiting condition for operation (LCO) action statements required that Unit 1 be in hot shutdown within 7 h and cold shutdown within 37 h under the following conditions: (1) Unit 1 operation after the loss of 1X03 using 2X03, without G05 operating, (2) loss of offsite power to both 1A05 and 1A06, or (3) loss of 1X04 transformer. The operating crew did not recognize that an LCO existed until 2158 when G05 and 2X03 were placed in service to transformer 1X04. This was within 3 h of the initial loss of offsite power to the Unit 1 safeguards buses, which is well within the Technical Specification LCO action statement guidelines. Safeguard buses 1A06 and 1A05 were aligned to offsite power on January 9, 1998, at 0046 and 0421, respectively.

On January 9, 1998, personnel noticed an ice buildup on the air intake line to gas turbine G05. Gas turbine G05 was taken off-line and the ice was removed. This caused an additional unrecognized entry into Technical Specification LCO action statements for about 1 h while the ice was removed.

F.2.3 Basis for Selection as an "Interesting" Event

Unit 1 suffered a loss of offsite power to the safety-related buses (1A05 and 1A06), but did not lose offsite power to the non-vital buses (1A03 and 1A04). This with two equipment failures left Unit 1 in an unusual electrical alignment. Auxiliary loads were not lost, EDGs were supplying the safety buses, and the unit remained at 98% power. The normal offsite power source, through transformer 1X03, was unavailable for approximately 69 h. Additionally, the licensed operating crew was not aware of all the Technical Specification LCO action statements that applied during this event because of the unusual alignment of the electrical system following the two independent component failures.

F.2.4 Factors of Interest

A decision in 1996 to classify the maintenance request for the bus duct heater as "minor" allowed this event to occur 18 months later. The 1994 design changes that received an inadequate design review then compounded the resulting bus fault. This prevented the fast bus transfer from occurring and would have affected both units despite which unit was supplying power to the auxiliaries. A ground detection alarm on January 5, 1998, potentially could have identified the bus duct heater problem. The plant-centered loss-of-offsite power to the safeguards buses revealed the fast bus transfer control circuitry deficiency.

F.2.5 References

1. Licensee Event Report 266/98-002, "Failure of the High Voltage Station Auxiliary Transformer," February 9, 1998.

F.3 LER No. 397/98-011

Event Description: ECCS pump room flooding because of a fire protection system pipe break

Date of Event: June 17, 1998

Plant: WNP 2

F.3.1 Event Summary

On June 17, 1998, while the plant was shut down in Mode 4 and residual heat removal pump A (RHR A) was operating in the shutdown cooling mode, a significant water hammer event in the plant's fire protection system piping resulted in the catastrophic failure of fire protection isolation valve FP-V-29D. This valve is located in the northeast stairwell of the reactor building. Water flowing out of the ruptured fire protection valve flooded the stairwell. Water also flowed into the RHR C room through an open water-tight door, and into the low-pressure core spray (LPCS) pump room via a failed-open valve in the floor located on elevation 129 m (422 ft). Because water covered the keep-full pumps, personnel in the control room started RHR B in the suppression pool cooling mode to maintain system operability. After verifying no fire or threat of fire existed, operations personnel shut off the operating fire protection pumps, thereby terminating the source of flooding. An Unusual Event was declared, and supplemental fire protection personnel and equipment were called to standby on-site until the operability of the fire protection system could be reestablished. The cause of the event was determined to be inadequate design of the fire protection system. Several contributing factors exacerbated the event. Just prior to the event the plant was shut down, and during the event two systems (one from each electrical division) were maintained available for shutdown cooling at all times.[1]

F.3.2 Event Description

At approximately 1343 on June 17, 1998, with the plant shut down in Mode 4 and RHR A in shutdown cooling mode, a significant water hammer event resulted in the failure of fire protection valve FP-V-29D. This valve is located in the northeast stairwell in the reactor building [floor level elevation 129 m (422 ft)]. Subsequent investigation determined that the water hammer was due to a pre-action system actuation from smoke that was generated as a result of cutting and grinding maintenance activities in a diesel generator room. Water from the ruptured fire protection valve flooded the stairwell to a level sufficient to cause deformation and failure of a fire door that lead to an adjacent vestibule. Once in the vestibule, flood water entered the RHR C room through a water-tight door which had not been properly dogged closed prior to the event. At ~1344, alarms associated with the actuation of the pre-action fire protection systems and the auto start of the fire pumps alerted control room personnel to a potential fire in the diesel generator corridor. At ~1345, high water level alarms for the RHR C room also alerted the operators in the control room to water leakage in the reactor building. Control room personnel entered into the Emergency Operating Procedures (EOPs) based upon this alarm. Because of the rising water level in the RHR C room, RHR-P-3 (the keep-full pump for RHR B and RHR C) tripped on an electrical fault. Control room personnel immediately started RHR B (located in a non-affected room) in the suppression pool cooling mode to maintain the system piping full of water and keep the system operational. RHR C pump room subsequently flooded to approximately elevation 134 m (439 ft) [about 5.2 m (17 ft) above the floor level], submerging the RHR C pump motor and other equipment in the room. As a result of the loud noise made by the water hammer, a Shift Support Supervisor in the area conducted a visual inspection and noted the flooding in the stairwell. The main control room was promptly notified, and at 1359, after verifying that there was no fire or threat of fire, control room personnel secured the fire pumps, terminating the source of flood water.

At ~1401, high water level alarms for the low-pressure core spray (LPCS) pump room annunciated in the main control room. Control room personnel also noted this as an entry into the EOPs. A floor drain isolation valve (FDR-V-609) had failed to automatically close, providing a flow path from the RHR C room sump to the floor drains in the LPCS room. Water flowed through this pathway from the sump up through the drains in the LPCS pump room. Attempts to close the valve from the control room was unsuccessful. With the water level rising in the LPCS room, LPCS-P-1 was started to maintain system piping full and keep the system operational, and LPCS-P-2 (the keep-full pump for LPCS and RHR A) was secured. At 1414, the Shift Manager declared an Unusual Event due to the non-functional fire protection system. At approximately 1427, the Hanford Fire Department was notified. They responded with fire protection personnel and equipment arriving on site at approximately 1443, and remaining on site until the fire protection system was restored to an operable status.

Subsequently, because of the rising water level in the room, LPCS-P-1 was secured. The rise of the water level in the LPCS room was stopped by the use of portable submersible pumps and manually closing FDR-V-609 by manipulation of the remote pneumatic actuator. The water level in the LPCS room peaked at about 15 cm (6 in) above the maximum safe operating level, or about 1.7 m (5 ½ ft) above the floor. Action was initiated to pump the water from the flooded areas to the storm drains and the radwaste system using portable submersible pumps. This effort resulted in a reduction of flood water to about 15 cm (6 in) above floor level by approximately 2205 that evening. The Unusual Event emergency classification was retained until the fire protection system was restored to service three days later.

F.3.3 Additional Event-Related Information

The licensee conducted an investigation into the cause of the failure of FP-V-29D and the subsequent flooding. A review of plant data revealed that, as designed, the fire protection jockey pump was running to keep the system pressurized prior to the event. Because of smoke generated from maintenance activities in a diesel generator room, pre-action sprinkler system 66 actuated and charged the associated spray header piping. The actuation of system 66 resulted in a system pressure drop, thereby causing the automatic starting of three main fire pumps. The resulting increase in system pressure caused the inadvertent actuation of pre-action system 81. About 30 s after the starting of the three main fire pumps, a fourth diesel-driven fire pump auto started as designed.

The licensee performed a detailed analysis to determine the hydrodynamic cause of the water hammer. The results of the analysis indicated that with only the jockey pump running, actuation of pre-action system 66 alone would have generated forces sufficient to cause the failure of FP-V-29D, and that the subsequent actuation of system 81 was incidental to this event.

F.3.4 Detailed Analysis

First, this event was analyzed with respect to the risk associated with the fire-induced flooding scenario occurring during the refueling outage (i.e., shutdown) and the resulting impact on safety-related equipment. The potential risk due to this scenario was determined to be negligible based on the following considerations:

- Since the event occurred while the plant was in cold shutdown, the decay heat level in the core was reasonably low. As a result, the plant operators had ample time to recover from any abnormal conditions.

- There were other redundant mitigating systems or system trains available:

  - RHR pumps A and B,
  - high-pressure core spray (HPCS) system,
  - condensate pumps,
  - reactor core isolation cooling (RCIC) system.

The conditional core damage probability (CCDP) because of the flooding event was estimated assuming that the event occurred while the plant was operating in Mode 1 (i.e., at power). This was done using the standardized plant analysis risk (SPAR) model for WNP-2. The results of this evaluation indicated that the impact of the flooding event on plant risk would also be insignificant if it occurred during power operation. This is mainly due to the availability of other redundant systems for accident mitigation.

Further, this event was analyzed with respect to plant risk associated with fire events because of the fact that this event actually disabled the fire suppression system. An attempt was made to quantify the increase in total core damage frequency (CDF) without taking credit for the fire suppression system. The licensee's individual plant examination (IPE)[2] and individual plant examination for external events (IPEEE)[3] were reviewed and the related findings are summarized below:

- The total fire CDF reported in the IPEEE is 1.8×10^{-5} per reactor year, of which 8.4×10^{-6} per reactor year is due to fire events in the control room. The licensee's fire risk study utilized the FIVE methodology for initial screening analysis.

- The IPEEE fire study considered approximately 90 fire zones. However, the licensee's analysis for only 10 of these fire zones took credit for the availability of the fire suppression system based on their locations and accessability of the fire suppression system. In the IPEEE, the fire suppression system unavailability was assumed to be 2.5×10^{-2} per demand and no other credit was taken for fire suppression.

  A closer review of the analysis of the 10 fire zones revealed that only 3 of them, namely RC-2A, RC-2B and RC-3, were dominant contributors to the fire risk. Fire zones RC-2A and RC-2B are in the cable spreading room and fire zone RC-3 is the cable chase. With no fire suppression system available, the preliminary CDF for each of these fire zones would be 2.8×10^{-5} per reactor year, 2.9×10^{-5} per reactor year, and 3.2×10^{-5} per reactor year, respectively. However, since the preliminary CDFs for these three fire zones calculated in the IPEEE were less than 1.0×10^{-6} per reactor year (with fire suppression system being available), as prescribed by the FIVE methodology, they were screened out and no further analyses were performed for them. For the other fire zones with preliminary CDFs of 1.0×10^{-6} or greater, more analyses (considering appropriate recovery measures) were performed to obtain more realistic CDFs. As a result, it could not be assumed that the above-identified CDFs were realistic without inclusion of applicable recovery measures. Because neither the IPE nor the IPEEE contained enough information about recoveries, the failure probabilities for recovery actions could not accurately be estimated and then applied in a consistent manner without obtaining additional information from the licensee to support the evaluation.

- For each of the three dominant fire zones identified above, the SPAR model for WNP-2 was revised appropriately, based on the impact table provided in the IPEEE fire study (Table 4.6-1). These revised models were then used to calculate preliminary CCDPs. The results were close to the values estimated in the licensee's IPEEE fire study.

To date, external events have not been considered in the ASP Program and, therefore, a consistent methodology for treatment of the external events has not yet been developed. Further, in light of the above discussion, any attempt to quantify the impact of the fire suppression system unavailability would only provide the potential increase in the calculated CDF due to fires, and not whether the WNP-2 event was an accident sequence precursor.

F.3.5 Basis for Selection as an "Interesting" Event

Interesting events are events that are not normally precursors as defined by the ASP Program; however, they provide insight into unusual failure modes with the potential to compromise continued core cooling following a design-basis accident. As identified by the licensee, the root cause of this event was the fire protection system design inadequacy, which could have generic implications. Other plants with similar fire protection system design features may have a similar susceptibility to water hammer events. Categorizing this event as an "interesting" event will better communicate its generic implications to the industry.

F.3.6 Factors of Interest

This event shows the difficulty in performing internal fire or flooding event analyses. Water from the ruptured fire protection valve flooded the stairwell to a level sufficient to cause deformation and failure of the fire door that led to an adjacent vestibule. From the vestibule, flood water entered the RHR C room through a water-tight door which had not been properly dogged closed prior to the event. RHR C pump room subsequently flooded to approximately elevation 134 m (439 ft) [about 5.2 m (17 ft) above the floor level], submerging the RHR C pump motor and other equipment in the room. A floor drain isolation valve (FDR-V-609) had failed to automatically close, providing a flow path from the RHR C room sump to the floor drains in the LPCS room. Water flowed through this pathway from the sump up through the drains in the LPCS pump room. The water level in the LPCS room peaked at about 15 cm (6 in) above the maximum safe operating level, or about 1.7 m (5 ½ ft) above the floor.

F.3.7 References

1. LER No. 397/00-011 "ECCS Pump Room Flooding Due to Fire Protection System Pipe Break," July 17, 1998.

2. WNP 2 Individual Plant Examination, July 1994.

3. WNP 2 Individual Plant Examination External Events, June 1995.

Appendix G:

Resolution of Comments on the

Preliminary 1998 Precursor Analyses

G.1 Comments

This appendix contains the comments received from the applicable licensees and the Nuclear Regulatory Commission (NRC) staff for the 1998 precursors. The comments for each precursor are listed and discussed in docket number order, where the docket number refers to the plant that reported the problem. Comments are further separated into licensee and NRC comments. Because of the length of the comments received, they are paraphrased, if necessary, in this appendix. Comments simply pointing out grammatical or spelling errors were addressed in the revision of the analyses but are not listed or addressed in this appendix. The reanalysis of precursors resulted in revisions to the preliminary precursor analyses contained in Appendix B of this report; these events are noted in Table G.1.

Table G.1 List of Comments on Preliminary Precursor Analyses

Event Number	Plant	Event descriptions	Page
LER 155/98-001	Big Rock Point	Standby liquid control system unavailable for 13 years	G.2-1
LER 269/98-004, -005	Oconee 1, 2, and 3	Calibration and calculational errors compromise emergency core cooling system transfer to emergency sump	G.3-1
LER 315/98-005	Cook 1	A postulated crack in a unit 2 main steam line may degrade the ability of the adjacent CCW pumps to perform their function	G.4-1
LER 346/98-006	Davis-Besse 1	A tornado touchdown causes a complete (weather-related) LOOP	G.5-1
LER 346/98-011	Davis-Besse 1	Manual reactor trip while recovering from a component cooling system leak and de-energizing safety-related bus D1 and nonsafety bus D2	G.6-1
LER 361/98-003	San Onofre 2	Inoperable sump recirculation valve	G.7-1
LER 454/98-018	Byron 1	Long-term unavailability (18 d) of an EDG	G.8-1

G.2 LER No. 155/98-001

Event Description: Long-term unavailability of the liquid poison control system

Date of Event: July 14, 1998

Plant: Big Rock Point Nuclear Plant

G.2.1 Licensee Comments

Reference: Licensee comments provided via e-mail message, "ASP Review/Comment Package," from Paul Harris, NRC Project Manager for Big Rock Point Nuclear Plant, Office of Nuclear Reactor Regulation, to Patrick O'Reilly, Office of Nuclear Regulatory Research, dated September 24, 1999.

Comment 1: On page 1 of the analysis report, under **Event Description**, first paragraph, last sentence, replace "five years" with "fifteen years."

Response 1: The identified change was incorporated.

G.2.2 NRC Comments

Reference: Note from Bruce Jorgensen, Region III, to Pat O'Reilly, Office of Nuclear Regulatory Research (RES), "PRELIMINARY BIG ROCK A. S. P.," dated August 17, 1999.

Comment 1: The potential failure of the liquid poison control system (LPS) pressure vessel itself, due to internal corrosion, is not addressed. For completeness, the analysis report might indicate whether the vessel itself was at risk (very unlikely) and whether any consequences might be associated with a postulated vessel failure.

Response 1: Failure of the LPS pressure vessel is one of the several mechanisms by which LPS failure could occur. However, the subject analysis assumed that the LPS was failed with a probability of 1.0, regardless of the mechanism. This assumption is considered bounding regarding any specific mechanism for LPS failure, such as pressure vessel failure.

Comment 2: The **Modeling Assumptions** provided the plant's "key features" for mitigating scram and poison injection failures listed in the licensee's 1994 IPE submittal. The LPS presumably failed as early as 1979. Were all the "key features" in place when the LPS "failed" in the 1979–1984 time frame? Some ATWS response procedures likely were developed after the Salem reactor trip breaker failure in 1983. No credit should be given for any features developed late in plant life in the conditional failure analysis.

Response 2: The analysis was performed on a per-year basis for the as-found condition of the LPS rather than by its year-by-year condition. It may indeed be true that the risk associated with ATWS scenarios was even higher prior to 1984; however, the answers to such questions are unknown. It appears that the inclusion of the plant's key features for mitigating scram and poison injection failures may have caused some confusion regarding the relevance of these features to the subject analysis. Since none of these key features were credited in the analysis, the **Additional Event-Related Information** has been revised to delete the discussion of these plant features.

Comment 3: There was a very specific failure mode in this case. As a result, no sodium pentaborate would have been injected into the reactor coolant system, but a large volume of nitrogen <u>might</u> have been. This raises a couple of issues which may need to be addressed:

- What would have been the effects of this nitrogen during the ATWS sequences, and are they taken into account?

- Would unintended LPS actuation (i.e., error or malfunction—not during an ATWS) have constituted an accident <u>initiating</u> event? Injecting a mass of nitrogen gas into the reactor coolant system might have been, in some operating modes, a very adverse event; this scenario isn't analyzed.

Response 3: The assumption regarding LPS failure is considered bounding on any additional scenario, such as the introduction of nitrogen into the reactor coolant system via the LPS.

G.2.3 NRC Comments

Reference: Note from Pete Wilson, Office of Nuclear Reactor Regulation (NRR), to Pat O'Reilly, RES, "Comments on the Preliminary ASP Analyses of Two Operational Events which Occurred at Surry 1 and Big Rock Point," dated September 10, 1999.

Comment 1: The loss of the LPS was assumed to be dominated by human error probabilities (HEPs). The HEPs for different sequences were identified from the time available for operators to actuate the LPS. In determining HEPs, factors other than time may significantly affect the outcome in some cases. How was it determined that these factors were not significant?

Response 1: In the analysis of this event, it was assumed that the failure probability for LPS was dominated by human error. This was believed to be a reasonable assumption considering the very short operator response times available following an ATWS. The LPS design at Big Rock Point consists of the liquid poison tank, piping, and electrically-operated valves. The combined failure probability for these components would be expected to be on the order of 1.0×10^{-2}, which is much smaller than the HEPs estimated by the licensee for the short-duration sequences (i.e., 3.0×10^{-1} for a 20 min operator response time).

Because information concerning the failure probability of the LPS hardware was unavailable (but was expected to be on the order of 1.0×10^{-2} based on a review of the system design), the assumption that the overall LPS failure probability was dominated by human error (HE) was used to extract the conditional frequency given LPS failure from the ATWS frequencies. For example, for Sequence 12:

$$freq_{12} \mid LPS = \frac{freq_{12}}{p(LPS)} = \frac{freq_{12}}{p(LPS,\ hardware) + p(LPS,\ HE)}$$

$$= \frac{1.7 \times 10^{-6}/year}{0.0 + 0.3} = 5.7 \times 10^{-6}/year$$

The fact that the IPE reported the ATWS HEPs as a function of time—which supported the assignment of an HEP to a sequence, because the IPE described the time available for response for each of the sequences—does not mean that only time was considered when estimating the HEPs. While the IPE does not elaborate, it is expected that the type of response (knowledge- or rule-based) and the amount of operator burden were considered in estimating the HEPs—a typical human reliability analysis (HRA) approach. The factors that contributed to the HEP estimates do not impact the analysis—the licensee's HEPs were accepted and used to extract an estimate of the conditional frequency for ATWS sequences, given LPS was failed.

G.3 LER No. 269/98-004, -005

Event Description: Calibration and calculational errors compromise emergency core cooling system transfer to emergency sump

Date of Event: February 12, 1998

Plant: Oconee 1, 2, and 3

G.3.1 Licensee Comments

Reference: Letter from W. R. McCollum, Site Vice President, Oconee Nuclear Site, to U. S. Nuclear Regulatory Commission, "Review of Preliminary Accident Sequence Precursor Analysis," July 15, 1999.

Comment: The ORNL precursor evaluation is thorough and well thought out. Overall, the values selected for the various parameters are reasonable. There is, however, one modeling assumption that Duke finds to be too pessimistic. Duke believes the nonrecovery probabilities assigned to LPR-REC (low-pressure recirculation recovered) are too high. It is recognized that insufficient information is available on the recovery being considered for quantification by any generally accepted technique. As a result, there is a natural tendency to assign conservative nonrecovery probabilities. The considerations that Duke believes provide a basis for less pessimistic assumptions regarding the potential for recovery are identified below. The timing estimates provided are based on RELAP and MAAP analyses of a large hot leg break with all engineered safeguards available.

Comment 1: The ORNL precursor evaluation assumed a nonrecovery probability of 1.0 for the large-break LOCA cases. Such an assumption implies complete certainty that the action will fail. A failure probability of 1.0 seems pessimistic for the following reasons.

1. Based on the RELAP and MAAP simulations, it is estimated that at least 30 min are available following the loss of coolant injection before core damage would begin. While there would certainly be some concern over the cause of failure of the previously operating low-pressure injection (LPI) pumps, it is also clear that inaction will lead to core damage [the inadequate core cooling section of the emergency procedure (EP) will be entered

following core uncovery]. Given that aligning the C LPI pump requires only a few minutes, at least 30 min are expected to be available for evaluation on the situation.

2. Significant core damage is not expected for more than 1 h following the initiation of the LOCA. The technical support center (TSC), or at least some of the TSC staff, should be available to assist in the evaluation.

3. These timing estimates assume a very large break of the horizontal portion of the hot leg. Breaks at locations higher than the horizontal run of the hot leg will provide significantly more liquid inventory in the reactor coolant system (RCS) at the time that coolant injection is lost and extend the time to significant core heatup. Breaks at the small end of the large-break LOCA range may also afford additional time.

For these reasons, we feel that a value of 1.0 for the nonrecovery probability reflects a degree of certainty that is not appropriate. A value of 0.5 for the nonrecovery probability would be indicative of complete uncertainty in the recovery potential, reflecting neither a pessimistic nor optimistic bias in the assumed recovery potential. A value of 0.5 is a more appropriate (but possibly conservative) selection for the nonrecovery probability.

Response 1: A nonrecovery probability of 1.0 was used for LPR-REC following a large-break LOCA because once the LPI pumps had failed, the short amount of time available would not support diagnosis and alignment of the third LPI pump. The models used for ASP analyses assume an undesirable end state when core uncovery occurs (see Appendix B to *Precursors to Potential Severe Core Damage, 1994, A Status Report*, NUREG/CR-4674, Vol. 21, December 1995). The LER reporting this event estimates core uncovery to occur about 7 min after the loss of low-pressure injection. The Oconee 3 Probabilistic Risk Assessment (PRA), Rev. 1, includes a 10-min time period to diagnose a loss of LPI and start and align LPI pump C (basic event LLP0P3CREC in the Oconee PRA) following the typical pump and valve failures addressed in the PRA.

In the modeling of this event, LPR-REC is applied only after the operators have failed to recognize the need to swap suction to the sump as the water level in the BWST continues to decrease, resulting in the failure of the LPI pump. As noted in **Modeling Assumptions**, operator burden (associated with the unusual nature of the instrumentation anomalies in addition to the existence of the large-break LOCA) plus annunciator noise would be expected to delay the operating crew's realization that the LPI pumps had failed and delay diagnosis of the failure and implementation of any recovery strategy until well beyond the time that core uncovery occurs, even if the large-break LOCA is somewhat smaller than double-ended or occurs at a more advantageous location in the hot leg. For this reason, a nonrecovery probability of 1.0 is considered appropriate for LPR-REC for a large-break LOCA and has been retained in the analysis. **Modeling Assumptions** has been expanded to provide additional detail concerning the assumption of 1.0 for the nonrecovery probability of LPR-REC.

Comment 2: The ORNL precursor evaluation assumed a nonrecovery probability of 0.5 for the medium LOCA cases. Such an assumption implies complete uncertainty in the success potential. A more optimistic view for the recovery potential is appropriate for the following reasons.

1. For the medium-break LOCAs, ~90 min is required to deplete the BWST inventory. The time to significant core heatup following the loss of injection should be longer than for the large LOCA case discussed previously. The time available for evaluation is sufficient to establish a reasonable understanding of the nature of the events.

2. The TSC is expected to be available prior to the loss of injection. Because the TSC will be in place during the important stages of the event, their evaluation is more likely to be rapid and correct. The availability of the TSC is expected to aid the control room in determining the appropriate action.

3. Considerations of break size and location that are not the most limiting would also contribute to a higher likelihood of success.

The availability of the TSC to monitor the accident and assist in the diagnosis and decision making is expected to provide reasonable reliability in arriving at an appropriate course of action. Success under these conditions is likely, and a nonrecovery probability of 0.1 is judged to be a more appropriate value. The medium-break LOCA situation is judged to be similar to the small-break LOCA situation because of the TSC availability.

Response 2: The availability of the TSC by the time that sump switchover is required following a medium-break LOCA is acknowledged, at least for day-time working hours. This availability would impact branch OPS-MIN as well as LPR-REC. Since LPR-REC is only demanded if the operators fail to effect transfer to the sump before the ECCS pumps fail, the TSC, if available, will have also failed to understand the event before pump failure. Considering the limited time available to recover recirculation (15 min based on the Oconee PRA description of LLP0P3CREC), the burden imposed by the unusual nature of the failure, and the expected difficulty in analyzing the nature of the failure,[a] a nonrecovery probability of 0.5 for LPR-REC (conditional on the failure of OPS-MIN) is considered appropriate and has been retained in the analysis. The intent was not to use 0.5 because there was complete uncertainty as to the recovery potential in a Bayesian sense, but to instead use the value because it was a reasonable

[a]See, for example, the analysis of LER No. 287/97-003 in the 1997 annual precursor report (*Precursors to Potential Severe Core Damage Accidents: 1997, A Status Report*, NUREG/CR-4674, Vol. 26, November 1998). In this event, two Oconee 3 HPI pumps were damaged during a reactor shutdown as a result of a low water level in the letdown storage tank. Over a 15-min time period following observation of low HPI pump discharge pressure, the operators started and stopped the two pumps and operated associated valves in an attempt to recover HPI pump discharge pressure before recognizing the potential cause of the problem and securing the pumps.

estimate of the conditional probability that LPR would not be recovered, given that OPS-MIN had already failed.

The medium-break LOCA CCDPs, accounting for the unavailability of the TSC, are 9.8×10^{-7} for Units 1 and 2 and 8.5×10^{-7} for Unit 3; the overall CCDP for the event is 1.7×10^{-6} at Units 1 and 2 and 1.4×10^{-6} for Unit 3. To address the impact of the potential availability of the TSC by the time that sump switchover is required, the conditional core damage probability (CCDP) for a medium-break LOCA was recalculated assuming the TSC would be available for all medium-break LOCAs at the time sump switchover was required. The resulting medium-break LOCA CCDPs are 6.5×10^{-7} for Units 1 and 2 and 8.2×10^{-7} for Unit 3; the overall CCDP for the event reduces to 1.3×10^{-6} at each unit. The **Analysis Results** has been revised to describe this result as a sensitivity analysis.

Comment 3: The discussion presented above provides suggested revisions to the nonrecovery probabilities assumed for LPR-REC. While even lower values than suggested might be appropriate, it is judged that the suggested values do not contain a significant bias in either a pessimistic or optimistic direction.

Response 3: See the above responses to comments.

References

1. LER 269/98-004, Rev. 1, "ECCS Outside Design Basis Due to Instrument Errors/Deficient Procedures," April 7, 1998.

G.3.2 NRC Comments

No comments were provided by NRC.

G.4 LER No. 316/98-005

Event Description: A postulated crack in a Unit 2 main steam line may degrade the ability of the adjacent CCW pumps to perform their function.

Date of Event: July 14, 1998

Plant: Donald C. Cook Nuclear Plant, Unit 2

G.4.1 Licensee Comments

Reference: Letter from M. W. Rencheck, Vice President, Cook Nuclear Plant, to the U. S. Nuclear Regulatory Commission, "Review of Preliminary Accident Sequence Precursor Analysis of Operational Condition,", November 8, 1999.

General Comments

Comment 1: The [NRC] staff's ASP analysis was not performed on an event that actually occurred. The analysis was based on a postulated event, as described in LER No. 316/98-005. The ASP analysis **Event Description** section accurately reflects the postulated event described in the LER abstract.

Response 1: No response is necessary.

Comment 2: The **Additional Event-Related Information** appears to accurately reflect the plant configuration and the potential steam escape paths. Additionally, the licensee confirmed the preliminary conclusion that there are no high stress segments in this area that are vulnerable to cracks or breaks and that these portions of piping are not susceptible to erosion/corrosion (E/C) effects.

Response 2: Based on our review of industry operating experience, we believe that we cannot exclude the possibility of erosion/corrosion-induced breaks (or water hammer-induced breaks, for that matter) in the feedwater line piping at the bends located in the immediate vicinity of the pipe chase. Therefore, our reanalysis of the reported condition considered this possibility.

Comment 3: Based on a review of the NRC staff's assessment and the technical issues surrounding the assessment, the licensee determined that the staff's calculated CDF for this postulated event was more than an order of magnitude too high. The discussion presented below details assessment areas that warrant reconsideration.

Response 3: Each of the licensee's specific comments was thoroughly considered. Due to the extensive, detailed nature of these comments, only the most important points of the comments have been summarized in the following discussion along with the appropriate response.

Specific Comments

Comment 4: The consideration of the two events at Millstone and their impact on the feedwater piping failure frequency should be removed from the ASP analysis. These events occurred in piping geometries that are not representative of the feedwater piping in question and were in locations that are not considered part of the feedwater system at the Cook plant. Removal of these two events from the analysis would cause the frequency for rupture of the subject main feedwater line to be identical to that of the two main steam lines in the vicinity of the CCW pump room doors.

Response 4: We agree with the licensee's comment. The two Millstone events were eliminated from consideration in the calculation of the estimated frequency of feedwater piping failure. In addition, in order to obtain a realistic estimate of the frequency using the largest data population possible, we expanded the time period considered from 1987–1995 to 1970–1997. Using this approach, there were two events that occurred in similarly sized (large bore) feedwater piping with similar thermal-hydraulic conditions which were considered in the calculation. These were the feedwater line break that occurred at Indian Point 2 in November 1973, and the feedwater line break that occurred at Surry 2 in December 1986. The revised estimate for feedwater piping failure was then used in our reanalysis of the reported condition.

Comment 5: The licensee stated that the staff's value of 5% assigned to the percentage of high energy line piping present in front of the doors that could impact the CCW pumps was overly conservative. Further, the licensee stated that a value of 1% for the percentage of high energy line piping situated near the CCW pump room doors was more appropriate.

Response 5: Based on our review of information provided by the licensee during discussions regarding their comments on our preliminary analysis of this condition, we revised the percentages of main feedwater and main steam piping used in our initiating event frequency estimate from 5% for both kinds of high energy piping to 2.5% for main steam and 1% for main feedwater piping. In order to maintain consistency between the numerator (piping failures) and the denominator (corresponding length of piping) in the frequency estimate, we considered only large bore piping [i.e., diameter greater than or equal to 25 cm (10 in)].

Comment 6: The licensee stated that they had confirmed their previous conclusion that there are no high stress piping segments in this area that are vulnerable to cracks or breaks and that these portions of piping are not susceptible to erosion/corrosion effects. They also stated that they had evaluated the feedwater line in question in accordance with their flow-accelerated corrosion program and had determined that the feedwater line in front of the CCW pump room doors is not susceptible to erosion/corrosion effects.

Response 6: Based on our review of industry operating experience, we believe that we cannot exclude the possibility of erosion/corrosion-induced breaks (or water hammer-induced breaks, for that matter) in the feedwater line piping at the bends located in the immediate vicinity of the pipe chase. Therefore, our reanalysis of the reported condition considered this possibility.

Comment 7: The licensee stated that the staff's assumed feedwater line break probability was a factor of ten higher than the break probability assumed in the Cook IPE performed in response to Generic Letter 88-20.

Response 7: We reviewed the IPE assumption and discussed this value with the licensee. We were unable to confirm the basis for the feedwater line break frequency used in the IPE. For this reason, we used an estimated feedwater line break frequency in our reanalysis that was based on recent operational experience data.

Comment 8: The licensee stated that feedwater is a chemically treated fluid, which is purposely maintained at low oxygen content, thus creating an unlikely environment for general corrosion. Corrosion is much more likely to be a concern in areas of flow stagnation, such as vent or drain connections. No such connections exist in the feedwater piping in the vicinity of the CCW pump room doors.

Response 8: Based on our examination of relevant pipe failure data (studies by SKI[1] and EPRI[2]), we believe that there is insufficient evidence to support the licensee's conclusion. The actual failure causes and mechanisms are too numerous to support a claim that a particular segment of piping has a higher or lower failure rate based on its specific attributes. In our reanalysis of this condition, we used an estimated feedwater line pipe rupture frequency (we did not consider cracks) for similarly sized feedwater piping that was based on recent operational experience data.

Comment 9: The licensee stated that a reanalysis of the reported condition using the changes to the modeling assumptions suggested in their comments would result in a change in core damage frequency of 9.0×10^{-7} (per year).

Response 9: Using the revised estimate of feedwater line rupture frequency obtained as briefly explained above and discussed in detail in the report of our final analysis, we reanalyzed the condition, obtaining an estimated increase in core damage probability (i.e., importance) of 3.0×10^{-6} for Unit 2, which means that this condition is a precursor for 1998. The importance for this event at Unit 1 was $< 10^{-6}$.

G.4.2 NRC Comments

No comments were provided by NRC.

G.4.3 References

1. Ralph Nyman et. al., *Reliability of Piping System Component, Framework for Estimating Failure Parameters from Service Data, SKI (Swedish Nuclear Power Inspectorate (SKI) Report 97: 26)*, December 1997.

2. Personal communications with cognizant EPRI staff and S. Weerakkody, U.S. NRC.

G.5 LER No. 346/98-006

Event Description: A tornado touchdown causes a complete (weather-related) loss of offsite power

Date of Event: June 24, 1998

Plant: Davis-Besse 1

G.5.1 Licensee Comments

Reference: Letter from G. G. Campbell, Vice President—Nuclear, to U. S. Nuclear Regulatory Commission, "Comments on Preliminary Accident Sequence Precursor Analysis of June 24, 1998, Operational Event at Davis-Besse Nuclear Power Station, Unit Number 1," March 27, 1999.

Comment 1: Page 2 of the preliminary ASP analysis, **Event Description**, states that the emergency diesel generators (EDGs) are qualified to 48.9°C (120°F). This is not correct because the only design characteristic that relates to this temperature value is the EDG room ventilation system that is sized to maintain each "operating" EDG room at 48.9°C (120°F), assuming 35.0°C (95°F) outside air.[1] The elevated temperatures will only affect the 40-year life of the EDG in terms of days (based on continuous operation during this period). Therefore, although the EDG was declared inoperable per plant procedures, it was in fact available and continued to provide essential electric power during the event.

Response 1: The discussion about the problems regarding temperature control in the EDG rooms contained in the first full paragraph on page B.5-2 of the analysis report has been revised to state that the EDG room ventilation system is sized to maintain each operating EDG room at 48.9°C (120°F), as pointed out by the comment.

As noted in the discussions on pages B.5-6 and B.5-7 (as well as in the preliminary analysis), the analysis of this event assumed that the impact of the EDG room temperature on the core damage probability (CDP) was negligible. Thus, no changes in the analysis assumptions were necessary to address this comment.

Comment 2: Page 6 of the preliminary ASP analysis (third bullet of <u>Failure of EDG 1 room ventilation recirculation damper</u>) states the maximum room temperature reached was 50.0°C (122°F). The maximum temperature recorded for the EDG 1 room, as cited in Potential Condition Adverse to Quality Report (PCAQR) 98-1294 (Ref. 2), was 51.7°C (125°F) at 1135 on June 25, 1998.

Response 2: The second bullet under Failure of the EDG 1 room ventilation recirculation damper in the analysis report (top of page B.5-7) has been revised to provide the correct maximum temperature.

Comment 3: Page 6 of the preliminary ASP analysis (third bullet of Failure of EDG 1 room ventilation recirculation damper) also reflects that a 48.9°C (120°F) room temperature is an "operability limit," which is incorrect as it relates to qualification of the EDGs. Per Comment 1 above, this is a procedural operability limit and a design parameter for the ventilation system.

Response 3: The second bullet under Failure of the EDG 1 room ventilation recirculation damper in the analysis report has been revised in the analysis report (top of page B.5-7) to provide the correction and associated clarification identified in the comment.

Comment 4: Page 6 of the preliminary ASP analysis (third bullet of Failure of EDG 1 room ventilation recirculation damper) states that the most limiting temperature of components in the room was 55.6°C (132°F). Evaluation of control cabinet components for PCAQR 98-1294 (Ref. 2) indicated that the EDG differential relays were the most limiting components, being certified for continuous operation at 55.0°C (131°F).

Response 4: The second bullet under Failure of the EDG 1 room ventilation recirculation damper in the analysis report (top of page B.5-7) has been revised to provide the correction and associated clarification identified in the comment.

Comment 5: The **Analysis Results** on page 7 of the ASP analysis assumed that a reactor coolant pump (RCP) seal loss-of-coolant accident (LOCA) could occur despite the loss of the RCPs due to failure of offsite power. This is not consistent with the seal failure model used in the DBNPS Probabilistic Safety Assessment (PSA). The seal failure model used by the Davis-Besse nuclear power station (DBNPS) is described in detail in the DBNPS individual plant examination.[3] It was concluded, based on testing and the design of the Byron Jackson RCP seal, that the seals will not experience gross leakage because of the loss of support systems as long as operators take appropriate actions to trip the RCP.[4] The DBNPS PSA model incorporates this conclusion by assuming an RCP seal LOCA only if plant operators fail to trip the affected RCP. This approach is consistent with other plants using Byron Jackson pumps and the same model/design seals. For the June 24, 1998, event, the RCPs tripped upon loss of offsite power (LOOP); therefore, an RCP seal LOCA should not be assumed anytime offsite power is not available.

Response 5: The RCP seal model used in the preliminary analysis was based on an earlier understanding of RCP seal failure mechanisms at Davis-Besse. The model has been revised to reflect our current understanding of the potential for seal failure given a station blackout for Byron Jackson RCP seals, based on seal performance during historically observed losses of seal cooling of greater than 1 h (including the 8-h loss of seal cooling test involving a Byron-Jackson N-9000 seal referred to in the Davis-Besse PSA). The revised model results in a somewhat reduced probability of seal failure compared to the preliminary analysis. As a result, RCP seal LOCA-related sequences also have lower probabilities compared to the preliminary analysis. However, this decrease is offset by an additional change that was made to the model used in the preliminary analysis (see the discussion that follows). The final conditional core damage probability (CCDP) estimated for the event is 5.6×10^{-4}. RCP seal LOCA sequences are minor contributors (~11%) to this value.

When modifications were being made to the Integrated Reliability and Risk Analysis System (IRRAS)-based model for Davis-Besse (standardized plant analysis risk model, a.k.a. SPAR model) used in the ASP analysis to address the comment regarding the RCP seal failure model, an error was discovered in the model logic. The specific model for Davis-Besse did not correctly model the probability that the pressurizer power-operated relief valve (PORV) would be challenged in the event of a station blackout. Instead, the model used in the preliminary analysis had used the PORV challenge probability for sequences involving a LOOP with successful emergency power system operation, which is 1.6×10^{-1}. To correct this, the modeling logic was modified to use the appropriate challenge probability, which is 3.7×10^{-1}. This value was obtained from a review of relevant operational experience data reported in LERs. When this change was combined with the RCP seal failure model changes discussed above, the net effect was a slight increase (~36%) in the estimated CCDP compared with the preliminary analysis.

References

1. *Davis-Besse Unit 1, Updated Final Safety Analysis Report*, Sect. 9.4.2.1.2.3.
2. Potential Condition Adverse to Quality Report (PCAQR) 98-1294.
3. Davis-Besse Unit 1, *Individual Plant Examination*, Part 3, Section 4.4.3, submitted by Serial No. 2119, February 26, 1993.
4. Operating Procedure DB-OP-02523, *Component Cooling Water System Malfunctions*.

G.5.2 NRC Comments

No comments were provided by NRC.

G.6 LER No. 346/98-011

Event Description: Manual reactor trip while recovering from a component cooling system leak and de-energizing safety-related bus D1 and nonsafety-related bus D2

Date of Event: October 14, 1998

Plant: Davis-Besse 1

G.6.1 Licensee Comments

Reference: Letter from Guy G. Campbell, Vice President - Nuclear, FirstEnergy Nuclear Operating Company, to United States Nuclear Regulatory Commission, "Comments on Preliminary Accident Sequence Precursor Analysis for the October 14, 1998 Operational Event at the Davis-Besse Nuclear Power Station, Unit Number 1," November 9, 1999.

Comment 1: The licensee commented in the referenced letter that the treatment of reactor coolant pump (RCP) seal loss-of-coolant accident (LOCA) in Scenario 3 of the precursor analysis was inconsistent with the approach taken in the Davis-Besse Probabilistic Safety Assessment (PSA). The PSA assumed, based on the design of the Byron-Jackson RCP seals, that the seals would not suffer catastrophic leakage due to loss of support systems provided the operators tripped the pumps. The Davis-Besse PSA incorporated this conclusion by assuming an RCP seal LOCA would occur only if an affected RCP were not tripped. Because the pumps were tripped upon loss of component cooling water during the October 14, 1998, event, the licensee stated that the analysis should assume that no potential for RCP seal LOCA existed.

Response 1: The RCP seal model used in the precursor analysis reflects our current understanding of the potential for seal failure given a station blackout for Byron Jackson RCP seals, based on seal performance during historically observed losses of seal cooling with durations greater than 1 h (including the 8 h N9000 loss of seal cooling test referred to in the PSA). The Standardized Plant Analysis Risk (SPAR) model for Davis-Besse used in the ASP Program's analysis recognizes, based on historic data, that there is a potential for an RCP seal failure if seal cooling is not recovered within one hour. As described in **Modeling Assumptions** (Sect. B.6.4, p. B.6-8), the seals are assumed to fail with probability 8.3×10^{-2} if seal cooling is unavailable for 1.5 h. The impact of the RCP seal failure model on the significance of the October 14, 1998, event is minor; Scenario 3 contributes less than 10% to the overall CCDP.

G.6.2 NRC Comments

No comments were provided by NRC.

G.7 LER No. 361/98-003

Event Description: Inoperable sump recirculation valve

Date of Event: February 5, 1998

Plant: San Onofre 2

G.7.1 Licensee Comments

Reference: Letter from A. E. Scherer, Manager of Nuclear Regulatory Affairs, Southern California Edison, to U. S. Nuclear Regulatory Commission, "Comments on Preliminary Accident Sequence Precursor Analysis of Linestarter Failure, San Onofre Nuclear Generating Station, Units 2 and 3," April 27, 1999.

Comment 1: **Modeling Assumptions and Analysis Results**: For Case 1 of the Accident Sequence Precursor (ASP) analysis [404 h, 55 min with only the Train A containment emergency sump outlet valve failed (valve HV-9305)], the common-cause failure probability of "Sump Isolation Motor-Operated Valves" failing to open was increased from 1.1×10^{-3} to 8.8×10^{-2}, based on the potential of the other sump isolation valves to fail also due to grit. In response to *NRC Special Inspection Report 50-361/98-05; 50-362/98-05* (Ref. 1), Southern California Edison (SCE) provided additional information relative to the estimated number of valve actuations (17,000) in the presence of the grit with only the one failure.[2] Based on this plant-specific data, there was no evidence that the potential for common-cause failure was impacted by the grit. Therefore, SCE concludes that the increase in common-cause probability is not appropriate.

Response 1: LER No. 361/98-003 indicates that grit was found in numerous Motor-Control Center (MCC) cubicles. Previous operational success of the Square D linestarters shows the durability of this equipment. However, because of grit being discovered in multiple locations, operational success did not preclude the grit failure mechanism from simultaneously affecting more than one linestarter. In fact, multiple safety components were affected by this failure mechanism; however, a list of affected equipment was not available. Therefore, only the sump isolation motor-operated valves were considered in this analysis. No supporting evidence was presented to suggest that the failure of the Train A containment emergency sump outlet valve linestarter was unique to just this one linestarter. No change to the analysis methodology was made based on this comment; however, additional justification for increasing the common-cause failure probability from the base case has been provided in the **Modeling Assumptions**.

Comment 2: **Modeling Assumptions** and **Analysis Results**: Case 3 of the ASP analysis [5 h, 45 min with the Train A containment emergency sump outlet valve failed (valve HV-9305) and the Refueling Water Storage Tank (RWST) Train B outlet valve unavailable because of maintenance (valve HV-9301)] models the unavailability of the RWST Train B outlet valve as a failure of that valve in the closed position thus preventing Train B injection. The RWST Train B outlet valve unavailability included in the LER was for replacement of the breaker-position indicating light. During this maintenance, the valve was open and available to allow injection. Therefore, from a probabilistic risk assessment (PRA) perspective, the 5 h and 45 min stated in the LER is not risk significant. This conclusion was included in Inspection Report 98-05 (Ref. 2).

Response 2: Because the RWST Train B outlet valve was in the open position and available during the injection phase of an accident, Case 3 was removed from the analysis. In addition, Item 5 in **Additional Event-Related Information** now indicates that the outlet valve was unavailable because of replacement of the breaker-position indicating light. This did not result in any change in the estimated overall importance of this event because the importance estimated for Case 1 increased slightly (1.0×10^{-7}), since its conditional time period was adjusted from 399 h, 10 min to 404 h, 55 min [i.e., the period with only the Train A containment emergency sump outlet valve failed (HV-9305)].

Comment 3: **Additional Event-Related Information:** The first paragraph infers that the linestarter replacement had just begun in February 1998. The linestarter replacement began in 1995 after the linestarter failure due to excessive wear of the sliding cams. The linestarter replacement was completed in 1998. It is suggested that "just started" in the first sentence be replaced with "been" to reflect the correct timing.

Response 3: This editorial change was made to reflect more accurately the timing of the linestarter replacement effort. The first sentence now reads "The licensee had been programmatically replacing all of the Square D linestarters—60 of 86 linestarters in Unit 2 and 61 of 86 linestarters in Unit 3 had already been replaced."

Comment 4: **Additional Event-Related Information:** The second paragraph includes information from LER No. 361/98-003, which indicated that the source of the grit was most likely gunite similar to what was used for hillside stabilization. In the response to NRC Inspection Report 98-05, additional information indicated that the grit substance had the same elemental visual and size characteristics as unmixed Portland cement. The response to NRC Inspection Report 98-05 further indicates that the deposition of the grit took place during construction activities and that potential sources included batch plant operation and grouting and guniting activities. It is suggested that the reference to gunite used to stabilize the hillside in the first sentence of the second paragraph be deleted and replaced with "... identified as Portland cement particles ...." In addition, it is suggested that the response to NRC Inspection Report 98-05 be referenced at the end of the second paragraph and added to the reference section.

Response 4: This editorial change was made to reflect more accurately the nature of the grit source. The first sentence of the second paragraph in this section now reads, "The grit that caused the linestarter for the Train A containment emergency sump outlet valve to jam was identified as Portland cement particles.[2]" The licensee's response to NRC Inspection Report 98-05 has been added to the list of references as Reference 2 in the analysis.

References

1. *NRC Special Inspection Report 50-361/98-05; 50-362/98-05*, May 21, 1998.

2. Letter from Dwight E. Nunn, Vice President, Southern California Edison, to U. S. Nuclear Regulatory Commission, "Response to NRC Inspection Report 98-05 Regarding Linestarters San Onofre Nuclear Generating Station, Units 2 and 3," June 22, 1998.

G.7.2 NRC Comments

No comments were provided by NRC.

G.8 LER No. 454/98-018

Event Description: Long-term unavailability (18 d) of an EDG

Date of Event: September 12, 1998

Plant: Byron Station, Unit 1

G.8.1 Licensee Comments

Reference: Letter from R. M. Krich, Vice President – Regulatory Services, to U. S. Nuclear Regulatory Commission, "Review Comments Regarding the Preliminary Accident Sequence Precursor Analysis for Byron Station, Unit 1," April 22, 1999.

Comment 1: **Event Description:** The ASP documentation appropriately characterized the sequence of events and the failure mechanism provided in LER 50-454/98-018.

Response 1: No response is necessary.

Comment 2: **Additional Event-Related Information:** The ASP analysis document is accurate with respect to the configuration of the plant, the design of the emergency diesel generators (EDGs) at Byron Station, and the continued availability of the 1B EDG.

Response 2: No response is necessary.

Comment 3: **Modeling Assumptions:** The assumption that the 1A EDG was unavailable for 18 d is overly conservative. There is reasonable assurance that the 1A EDG became unavailable on September 3, 1998, and was therefore, unavailable for 11 d instead of 18 d. LER 50-454/98-018 did indicate that although the actual failure point could not be determined, the EDG was considered unavailable for 11 d – from September 3, 1998, until September 14, 1998. The basis for this consideration is that plant operators identified a lifting relief valve on the 1A EDG on September 3, 1998. Prior to September 3, 1998, there was no indication of this relief valve lifting. Although the initial operability determination that was performed after identification of the lifting relief valve did not consider the potential for a plugged lube oil strainer, there is a reasonable belief that the condition did not exist prior to September 3, 1998, since the lifting relief valve would have been noted by plant operators on daily rounds or other plant personnel during routine course of activities.

Response 3: There is evidence that the 1A EDG was failed on September 3, 1998. However, there is no concrete support for a fixed point in time prior to September 3, 1998, when the 1A EDG may have no longer been able to run continuously for its required 4-h mission time. Prior to the relief valve lifting, there would have been fibrous material building up on the internal surface of the strainer element until sufficient back pressure was established to lift the relief valve. This buildup could have been accelerated by an EDG autostart prior to the point in time when the relief valve eventually lifted. Therefore, assuming the 1A EDG was failed only after that point in time when the operators noted that the relief valve lifted does not seem appropriate. A reasonable estimate is to assume that the EDG would be unavailable for one-half of the period between the last successful surveillance test (August 19, 1998) and when the clogged strainers were positively identified (September 3, 1998)–a 15-d period. This 7.5-d window before the relief valve was noted to have lifted is in addition to the 11-d period that the 1A EDG was known to be failed. This results in a total unavailability of ~18.5 d. An 18-d window was analyzed.

If the relief valve lifting was not considered proof that the 1A EDG was failed, then a typical failure window of one-half of the 26-d period since the last successful surveillance test would be assumed. Such a 13-d window was analyzed as a sensitivity study. No significant change in the calculated importance for this event was observed after adjusting the EDG unavailability period from 18 d to 13 d. The sensitivity study has been documented as part of the analysis.

Comment 4: **Modeling Assumptions:** In the ASP analysis document, it appears that the assumptions overly compensate for the potential for a common-mode failure of the remaining EDGs. There is no indication that the remaining three EDGs were ever impacted by the particular event documented in LER 50-454/98-018. The Byron Station Technical Specifications required plant operators to immediately perform an assessment of the common-mode failure potential for the 1B EDG. In addition, temporary modifications were installed on all four of the EDGs following this event to allow plant operators to monitor the EDG lube oil strainer differential pressures to ensure that the condition was not common to more than the one diesel generator. No evidence to date has been identified which supports the common-mode failure assumptions contained in the ASP analysis document. This conclusion is supported by the fact that maintenance is not performed on multiple EDGs at one time and there is no single dedicated crew that is responsible for performing maintenance on all the EDGs. Lack of attention to detail by maintenance personnel is one of the significant contributors identified in the root cause analysis for this event. Therefore, given the objective evidence, including inspection activity during the condition, there is little reason to believe that the calculations indicate that a re-characterization of the failed condition of the 1A EDG as a non-common-cause potential failure results in a net increase in core damage probability of less than 1.0×10^{-6}.

Response 4: LER 454/98-018 (p. 3) states that "other factors that contributed to the event were determined to be an inadequate maintenance procedure and inadequate maintenance practice." Both causes would transcend a single maintenance crew. Furthermore, crushed filter media degrades at variable rates. Therefore, the fact that this maintenance is not performed simultaneously does not preclude this failure mechanism from simultaneously affecting more than one EDG. Finally, action taken after the discovery of this event does not remove the increased potential for common-cause failure based on the identified event factors. No change to the analysis methodology was made based on this comment. However, additional justification for increasing the common-cause failure probability from the base case has been provided in the **Modeling Assumptions**.

Comment 5: **Modeling Assumptions:** The design basis for the Byron Station is such that any single EDG is capable of providing sufficient ac power to provide the capability to safely shutdown both units in the event of a Station Blackout (SBO). This design basis is documented in Byron/Braidwood Updated Final Safety Analysis Report (UFSAR) section 8.3.11.2.2, "Emergency Onsite Power Sources (Diesel Generators)". Credit does not appear to be given to this design basis in the **Modeling Assumptions.** We would suggest that such credit is appropriately taken by multiplying each "MULTI-UNIT-LOOP" cut set associated with a SBO sequence, none of which contain a common-cause EDG failure term by the value represented by basic event "EPS-XHE-XM-OU."

Response 5: Because a single EDG is capable of providing sufficient ac power to safely shutdown both units if there is an SBO, basic event MULTI-UNIT-LOOP was removed from the NRC's standardized plant analysis risk (SPAR) model for Byron Station, Unit 1. The calculated importance of this event was revised from 6.9×10^{-6} to 5.6×10^{-6}. This change represents a 20% reduction from the original calculation.

Comment 6: **Modeling Assumptions:** It appears that a value of 0.8 was used as the failure probability for offsite power recovery for all sequences. This value, in most cases, is overly conservative. Furthermore, this value appears to be used in all sequences, regardless of the expected accident progression time to core damage.

For the Byron Station Updated Probabilistic Safety Assessment (PSA), there were essentially three different post-SBO scenarios postulated. The first post-SBO scenario, which best correlates to Sequence 18-2, has a successful diesel-driven Auxiliary Feedwater (AFW) pump combined with a reactor coolant pump (RCP) seal loss-of-coolant accident (SEALLOCA) probability that results in the core being uncovered at 8 h. The 8-h period is based on a reasonable assumption that battery depletion occurs 4 h into the event and results in AFW failure. However, there is sufficient secondary inventory in the steam generators and primary inventory in the RCS to provide an additional 4 h prior to core damage when considering the reduction in decay heat that has occurred in the first 4 h following the initiating event. Thermal-hydraulic analysis performed for the Byron Station Individual Plant Examination (IPE) has demonstrated the core will remain covered for at least 2 h with this primary and secondary inventory available immediately following such an initiating event. In the preliminary ASP analysis, decay heat was initially assumed to be at its maximum value and was reduced exponentially as a function of time. Therefore, use of an ac power non-recovery probability corresponding to an 8-h period would be more appropriate for this sequence.

The second post-SBO scenario in the Byron Station Updated PSA, which best correlates to Sequence 18-9, includes the same plant conditions discussed in the first scenario (Sequence 18-2), except that the core does uncover (i.e. the SEALLOCA probability is sufficiently large) in less than 8 h, such that recovery of ac power at 8 h is of no value for avoiding core damage Sequence 18-9 does credit such recovery. But with 0.8 ac power non-recovery probability, there appears to be a presumption that very little time is available prior to core damage following the RCP seal failure. Given Byron's offsite ac power non-recovery probability vs. the time after a loss of offsite power (LOOP)/dual-unit loss of offsite power (DLOOP) events curve, the ac power non-recovery probability of 0.8 appears to be reasonable for this sequence.

The third post-SBO scenario in the Byron Station Updated PSA, which best correlates to Sequence 18-22, postulates the failure of the diesel-driven AFW pump. As demonstrated in the thermal hydraulic analysis performed for the Byron Station IPE, ac power recovery must occur within 2 h in order to avoid core damage. Although there is a potential for a large enough SEALLOCA to uncover the core in less than 2 h, rendering the recovery of ac power meaningless, accounting for this will have a second or third order effect on overall core damage frequency, as this is already in a low probability sequence. Therefore, use of an ac power non-recovery probability corresponding to a 2-h period would be more appropriate for this sequence.

In addition, the preliminary ASP analysis document event tree included Sequence 18-20. This sequence postulates the cycling of a pressurizer power-operated relief valve (PORV), presumably due to an expected reactor coolant system pressure transient following the initial turbine trip and loss of the condenser and the steam dump valves. The scenario continues with the PORV failing to re-close, resulting in an effective small break loss-of-coolant accident (LOCA). Again a 0.8 ac power non-recovery probability was assigned. Thermal hydraulic analyses from the Byron Station IPE indicate that such a scenario (i.e., the largest small-break LOCA) would progress for slightly more than 2 h prior to core damage occurring. Therefore, use of an ac power non-recovery probability corresponding to a 2-h period would be more appropriate for this sequence.

Given the previous discussion of Sequences 18-2, 18-9, 18-20, and 18-22, use of ac power non-recovery probability values that correlate to time durations of 2 h or 6 h, respectively, after the LOOP/DLOOP event would be more appropriate for the sequences where the time to core damage is 2 h or 8 h, respectively. The ac power non-recovery probability values in the Byron Station Updated PSA database for these time durations are 0.316 and 0.032, respectively.

These ac power non-recovery probability values were derived from Electric Power Institute Research (EPRI) Report TR-106306, "Losses of Off-Site Power at U.S. Nuclear Power Plants—Through 1995," dated April 1996. This study covered approximately the same time period as NUREG/CR-5496, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980–1996," dated November 1998, which is referenced in the preliminary ASP analysis document. In addition, EPRI Report TR-106306 covered more industry events than NUREG/CR-5496 and was in a final published form, whereas NUREG/CR-5496 was only in draft form at the time we performed our ac power non-recovery probability calculations.

The determination of the ac power non-recovery probability values was accomplished via a thorough review of EPRI Report TR-106306 and of the LOOP/DLOOP events in its database. Certain events that clearly did not apply were excluded. Primary examples of excluded events pertain to those caused by hurricanes and salt spray. Hurricanes were only partially excluded to give some representation of the recent Davis-Besse tornado event. In addition, any single-unit LOOP at a multi-unit site which was terminated by simply cross connecting to another unit's power supply was also excluded, in order to obtain a more accurate picture of offsite ac power recovery. The remaining events were plotted on a chart and curve fit. The 2-h duration value was determined from the curve fit. For the 8-h duration value, a value from the curve fit was interpolated to avoid non-conservative predictions by the curve fit equation in the region of the curve corresponding to 8 h. The resulting ac power non-recovery probability values are considered reasonable and reflective of actual industry experience, as applied to Byron Station.

Response 6: **Modeling Assumptions:** In the SBO sequences, the probabilities of a reactor coolant pump (RCP) seal loss-of-coolant accident (LOCA) and of failing to recover ac power at various points in time are calculated using a convolution approach that recognizes that all probabilities are a function of time. A Weibull distribution is used to predict the LOOP-related parameters applicable for Byron as defined in ORNL/NRC/LTR-89/11 (Ref. 1). Probabilities associated with the failure to recover ac power and the potential for an RCP seal LOCA are calculated given that ac power was not restored at specific points in time. Additionally, the probability for the operators' failure to restore emergency power is based on the assumption that the median repair time for an EDG is 4 h, as developed in NUREG-1032 (Ref. 2). The ac power non-recovery probabilities (typically valued at 0.8) in the Byron SPAR model are conditional probability values. These ac power non-recovery basic events represent the probability that an ac power source is not reestablished before core damage occurs *given* that power has not been restored at a particular reference point (i.e., battery failure or an RCP seal LOCA). The Byron PSA ac power non-recovery probability values appear to be based on an historical evaluation of the total elapsed time since the initiation of an SBO event. The conditional probabilities for basic events LOOP-18-02-NREC, LOOP-18-09-NREC, LOOP-18-11-NREC, LOOP-18-18-NREC, LOOP-18-20-NREC, and LOOP-18-22-NREC in the Byron IRRAS model do not represent the same probabilities that Byron PSA ac power non-recovery probability values (0.316 and 0.032) represent. Therefore, the free substitution of non-recovery values from the Byron PSA into the Byron SPAR model is inappropriate without making further adjustments to the other LOOP-related parameters in the Byron SPAR model.

Accounting for the conditional attributes of the ac power recovery basic events in the Byron SPAR model, the 2-h and 8-h ac power non-recovery probability values can be approximated as 0.42 and 0.02, respectively, when taken over the entire time interval. These values are not significantly different from the historically generated values used in the Byron PSA (0.32 and 0.03, respectively). No change to the analysis methodology was made as a result of this comment.

References:

1. *Revised LOOP Recovery and PWR Seal LOCA Models*, ORNL/NRC/LTR-89/11, August 1989.

2. P. W. Baranowsky, *Evaluation of Station Blackout Accidents at Nuclear Power Plants*, NUREG-1032, U.S. Nuclear Regulatory Commission, June 1988.

G.8.2 NRC Comments

No comments were provided by NRC.

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10. SUPPLEMENTARY NOTES

11. ABSTRACT *(200 words or less)*

This report describes the nine operational events in 1998 that affected nine commercial light-water reactors (LWRs) and that are considered to be precursors to potential severe core damage accidents. All these events had conditional probabilities of subsequent severe core damage greater than or equal to 1.0 × E-6. These events were identified by first computer-screening the 1998 licensee event reports from commercial LWRs to identify those events that could be precursors. Candidate precursors were selected and evaluated in a process similar to that used in previous assessments. Selected events underwent an engineering evaluation to identify, analyze, and document the precursors. Other events designated by the Nuclear Regulatory Commission (NRC) also underwent a similar evaluation. Finally, documented precursors were submitted for review by licensees and NRC headquarters to ensure that the plant design and its response to the precursor were correctly characterized. This study is a continuation of earlier work that evaluated 1969-1997 events. The report discusses the general rationale for this study, the selection and documentation of events as precursors, and the estimation of conditional probabilities of subsequent severe core damage for the events.

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